

Oil & Natural Gas Technology

DOE Award No.: DE-FC26-04NT15456

Technical Progress Report Final

State Support of Domestic Production

Submitted by:
Interstate Oil and Gas Compact Commission
900 North East 23rd Street
Oklahoma City, OK 73152

Prepared for:
United States Department of Energy
National Energy Technology Laboratory

March 31, 2008
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Office of Fossil Energy



Technical Progress Report

Final

Reporting Period Start Date: July 01, 2004

Reporting Period End Date: December 31, 2007

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Federal Projects Manager

Date Report submitted: March 31, 2008
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ABSTRACT

This project was developed in response to a cooperative agreement offering by the U.S. Department of Energy (DOE) and the National Energy Technology Laboratory (NETL) under the State Support of Domestic Production DE-FC26-04NT15456. The Interstate Oil and Gas Compact Commission (IOGCC) performed efforts in support of State programs related to the security, reliability and growth of our nation's domestic production of oil and natural gas.

The project objectives were to improve the States' ability to monitor the security of oil and gas operations; to maximize the production of domestic oil and natural gas thereby minimizing the threat to national security posed by interruptions in energy imports; to assist States in developing and maintaining high standards of environmental protection; to assist in addressing issues that limit the capacity of the industry; to promote the deployment of the appropriate application of technology for regulatory efficiency; and to inform the public about emerging energy issues.

The areas of interest the IOGCC focused on over the duration of the contractual agreement are, but not limited to:

Regulatory Streamlining and Improvement
Technology
Training
Resource Assessment and Development

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INTRODUCTION

This is the Final Technical Progress Report for the Department of Energy (DOE) Project titled *State Support of Domestic Production* submitted by the Interstate Oil and Gas Compact Commission (IOGCC) under DOE Grant number DE-FC26-04NT15456. This report documents and summarizes all work performed for the contractual project period of July 1, 2004 thru December 30, 2007. This report will present the findings produced as a consequence of the work done by the IOGCC as well as conclusions drawn from the research as a whole.

Regulatory Streamlining and Improvement efforts support the IOGCC's regulatory efforts that include the identification and elimination of unnecessary duplications of efforts between and among state and federal programs. Technology efforts were implemented to improve efficiency in states through the identification of technologies that reduce costs. Training and Education programs were vital to upgrading the skills of regulators and industry personnel. Acting through the governors' offices, states have been effective conduits for the dissemination of energy education and training information and events. Resource Assessment and Development related directly to helping maximize production of domestic oil and natural gas resources that included but were not limited to areas that are under explored or have not been adequately defined.

EXECUTIVE SUMMARY

The goal of this project was to provide assistance to the state governments in the effective regulation of the exploration and production of domestic natural gas and oil. Taken as a whole, the projects under this award serve State governments by streamlining regulatory processes, creating the ability to share best practices; identify performance measures that verify compliance with State exploration, production and environmental regulations; provide information on new technology to increase regulatory compliance, environmental protection and efficiency; and conduct regional or national projects that States acting alone cannot achieve.

Industry was served by more effective and efficient regulatory processes and by providing a forum for discussing issues of common concern.

The public was served by the excellent environmental protection programs operated by the states, while industry is able to provide critical energy resources for the country. The public benefits daily from the production of domestic natural gas and crude oil.

Project areas of interest were regulatory streamlining and improvement; technology; training and education; and resource assessment and development. The identified areas of interest were designed and implemented to better prepare the oil and gas industry, state and federal regulators, and the environmental community in this 21st Century and the energy problems associated with the changing needs of the world.

WORK STATUS AND PROGRESS

Regulatory Streamlining and Improvement

Regulatory Streamlining and Improvement of work involves identifying and eliminating unnecessary duplication of efforts between and among state and federal programs dealing with exploration and production. The Interstate Oil and Gas Compact Commission (IOGCC) accomplished the following strategic Regulatory Streamlining and Improvement during the project period:

Review Applications to Drill Process - The IOGCC formed an Information Technology work group composed of key state information technology experts in March of 2004. The group studied the IT initiatives in the states with the most advanced application of technology. This technology transfer was valuable to states with less sophisticated technology processes, and aided in designing new systems and implementing processes that streamlined permit reviews.

IOGCC-EPA MOU Task Force - The U.S. Environmental Protection Agency (EPA) and the Interstate Oil and Gas Compact Commission have a Memorandum of Understanding (MOU) to provide for long-term improvement in communication and to create a permanent means of consultation as new natural gas and oil exploration and production issues emerge. Created to implement the objectives of the MOU, a Task Force of senior EPA officials, state directors, and IOGCC staff, meets and works to identify mutually beneficial joint activities including training, field visits, and technical symposiums. Between meetings, informational briefings on technical studies, proposed and final rule making, policies, and guidance are conducted by conference call. Task Force discussions have included storm water controls for oil and gas facilities, hydraulic fracturing as a possible pollutant to ground water, regulations for the prevention and control of oil spills, national air quality standards, the definition of navigable waters under the Clean Water Act, and carbon capture and sequestration. The agendas and attendance records for IOGCC-EPA MOU Task Force are included herein as *Appendix A*.

IOGCC Committees - The IOGCC utilized committees and subcommittees that were made up of volunteers provided by the states and industry. The IOGCC operates through standing committees and its subcommittees/work groups, each consisting of members appointed by IOGCC governors or their official representatives. Standing committees involved in providing invaluable assistance in various areas of this grant were: Energy Resources, Research and Technology Committee (ERRT), Environment and Safety Committee, State Geologist Forum, Council of State Regulatory Officials (CSRO), Legal and Regulatory Committee, Public Lands Committee and the Public Outreach Committee. The Split Estate Subcommittee of the Legal and Regulatory Committee became active and discussed such issues as water rights, regulatory takings, and drafting model statutes. The proposed model statutes were submitted to the committee in March 2007 and discussed at the IOGCC Midyear Meeting in Point Clear, Alabama, in May

2007. Other topics included proposals for protecting a surface owner's interest in ground and surface waters and proposals for limiting or defining the scope of municipal regulation of oil and gas development.

The IOGCC publishes a document annually entitled "Investments in Energy Security: State Incentives to Maximize Oil and Gas Recovery" that provides information on what incentives various member states are providing to industry to spur development of new oil and natural gas resources for both conventional and unconventional exploration techniques. Attached Incentives as *Appendix B*.

The IOGCC publishes an annual "Summary of State Statutes" for all member states and conducts a yearly survey of state statutes and regulations pertaining to oil and natural gas production. In assembling this summary of statutes, rules, and regulations, each member and associate member state of the IOGCC was supplied a questionnaire for submission of the desired information, which was edited by headquarters office personnel. Survey results were published in IOGCC's "Summary of State Statutes and Regulations for Oil and Gas Production," which is available in hardcopy (a binder) and on CD-ROM. The IOGCC distributes the publication to its subscribers. It is also available for purchase on the IOGCC Website. Attached as *Appendix C*.

The IOGCC also printed a new edition of its 2004 Model Statute for Conservation. Throughout its existence, the IOGCC has sought to help states conserve oil and gas. One of the many ways in which this has been accomplished is through the drafting of model statutes. The statute was distributed to IOGCC member state governors and representatives and is available on the IOGCC Website. Attached as *Appendix D*.

Technology

Identifying technologies that reduce costs to the states and oil and gas operators improved efficiency in states. The IOGCC accomplished the following technology transfer improvements during the project period:

The IOGCC's IT work group reviewed the existing applications and helped states avoid "reinventing the wheel" in relationship to web-based permitting and streamlining business processes. The IOGCC's IT work group met in October 2005 to share experiences in the on-line permitting activities and efforts to justify the cost of technology to management. Thirteen states participated in the work group to discuss the complex and costly issues of project management. One of the documents shared among participants was the Texas Railroad Commission's Information Technology Services Division report titled "Post Implementation Evaluation Review (PIER) for Electronic Compliance and Approval Process (ECAP)".

IT Conference - The IOGCC planned an IT conference that was held August 29, 2007, in Casper, Wyoming. The IOGCC and the Wyoming Oil and Gas Conservation Commission (WOGCC) invited IT departments of oil and gas producing states to a day-long educational demonstration and roundtable discussion of the Wyoming web-based reporting system. Wyoming has one of the most advanced and interactive systems in the country and the IOGCC wanted to take the opportunity to share this information.

The meeting was the first of its kind. The IT staff that supports the web interface for many of the IOGCC states convened in Casper. Rick Marvel of the WOGCC led and facilitated the meeting and demonstrated the progress made on the site and the collaborative efforts that have been accomplished in partnering with IHS. All IOGCC state offices are interested in interactive website services and electronic permitting initiatives to support more efficient and timely processing of data. Opportunities exist at all offices to facilitate their technology implementation efforts and improve workflows for sharing data and meeting their Web audience needs. Attached Attendance and Agenda as *Appendix E*.

Training and Education

Training and Education were vital to upgrading the skills of regulators and industry alike. IOGCC staff surveyed the member states for a more complete understanding of programs they deemed most appropriate for management, field, and office personnel. The IOGCC implemented the following training and education programs during the project period:

Performance Measurement – The goal was to provide technical assistance to states to develop and implement performance measurement into their management practices that will provide quality results and outcomes that can be easily quantified. These results and outcomes can be provided easily in a report format that indicates they are achieving their stated missions.

A second goal of this project was to work with states in aligning their performance measurements as closely as possible with those of federal program requirements established through the President's Management Agenda and the Government Performance and Results Act (GPRA). Achievement of this goal could complement and assist federal government agencies and programs in meeting their specified performance goals and missions.

Performance Measurement was an important aspect of training and education. Michigan was the first state to receive assistance for its oil and gas regulatory program. The assistance involved the managers of each program spending 3-5 days assessing the overall mission and vision of the Michigan Office of Geological Survey (OGS) and each of the OGS programs' regulatory responsibilities. This exercise enabled the managers to develop environmental, public health, and safety measures to track efficiency, effectiveness, and improvement. Deliverables, attendance sheets, and evaluation forms filled out by participants are attached as *Appendix F*.

The second state to receive performance measurement assistance was Oklahoma. Weidner Consulting of Austin, Texas, provided workshop assistance to the managerial staff of the Oklahoma Oil and Gas Conservation Division (OGCD) from December 12-16, 2005. The OGCD regulates oil and gas exploration and production activities in Oklahoma. Twenty-three state regulatory officials from the OGCD were involved in the process. By going through this exercise with the managers they were able to develop environmental and public health and safety measures to track efficiency, effectiveness, and improvement over time.

The Utah Division of Oil, Gas and Mining (OGM) managerial staff received the performance measurement assistance in July 2006, from Weidner Consulting. Twenty individuals with the Utah program participated in the week-long workshop and a Strategic Business Plan was prepared as a deliverable to OGM.

Identifying key educational gaps was important to the IOGCC. These gaps included the lack of understanding about the relationship between research and development and oil and gas exploration and production; the importance of domestic resources to national security, and the regulatory structure governing industry. The IOGCC prepared six articles addressing these issues and used them to educate the public through mass media.

To aid member states in providing information about hydraulic fracturing to the public, the IOGCC created a brochure to distribute to state oil and gas directors. The brochure focused on the results of a four-year U.S. Environmental Protection Agency study. The brochure, which summarized the study, the outcome, and the multi-step definition of the process, was an excellent tool for the states to educate the public about how effective state regulatory programs made it possible for the United States to maximize and conserve the nation's resources in a safe and environmentally sound way. The brochure is attached as *Appendix G*.

The IOGCC surveyed member states in January 2006 to determine the need for personnel training. Ten states responded to the survey and identified areas for which they would be interested in receiving training workshops. The areas that held the most interest are Global Positioning Satellite (GPS), Blow-Out Preventers, Naturally Occurring Radioactive Materials (NORM), and Waste Minimization and Spill Prevention Control and Countermeasures. Due to funding limits, the IOGCC was able to provide only the NORM training to a total of 140 field inspectors.

The Blue Ribbon Task Force (BRTF) was formed by Gov. John Hoeven of North Dakota to implement the Petroleum Career Educational Program. The IOGCC published the "Petroleum Pros," an award winning publication released in the fall of 2004. Petroleum Pros presented the findings of the BRTF to interest students in careers in the petroleum industry. This publication received widespread recognition and was distributed to key public officials, industry leaders, and industry press, as well as the popular press. The Petroleum Pros publication is attached as *Appendix H*.

The National Inspector Certification Program worked with IOGCC member states to evaluate their oil and gas field inspectors. Prior to 2000 no official national program had been established to standardize inspections of oil and gas operations. The IOGCC formed a committee in October 2004 to review and update the certification exam to ensure that all topics were current and relevant. The revised exam was approved in July 2005 and an offshore module of the exam was put into development. To enhance the program's effectiveness the IOGCC communications staff created a brochure to outline the program's benefits both to state oil and gas directors and their inspectors. Since the development of this program, twelve IOGCC member states have utilized the exam and approximately 120 inspectors have been tested. The National Inspector Certification Exam and brochure are attached as *Appendix I*.

Updating Public Access to IOGCC Information through innovation and its Website was a critical objective during the project period. A brochure, "A Dependent Nation: Recommendations for Energy Security," was widely distributed to educate key constituents about the problem of energy dependence and the much-needed energy policy. The IOGCC Public Outreach Committee worked on several projects to better educate the public about the importance of oil and natural gas resources. The IOGCC passed resolution 05.094 in October 2005 expressing the need for a national energy education program. Recognizing the growing vigor to formulate oil and gas energy education efforts, the committee developed a Communication Resource Guide to bring a better understanding to the dynamics of formulating a national oil and gas energy education effort. The Guide categorizes oil and gas energy education and public outreach efforts by activity. The arrangement allows interested parties the ability to "review-at-a-glance" specific oil and gas energy education and public outreach activities conducted by various groups nationwide. More than 30 organizations are represented in the Guide, which is a vital step toward developing a national oil and gas energy education program. The Guide was distributed to members of the IOGCC Public Outreach Committee and has been made available for downloading on the IOGCC Website.

The IOGCC revamped its Website for easier navigation and readability and re-branded the organization for a more high level and professional image.

Resource Assessment and Development

Resource assessment and development are related directly to helping maximize production of domestic oil and natural gas, including areas that are under explored or have not been adequately defined. The IOGCC has made huge strides in this area, including, but are not limited to, publications that highlight potential resources.

Appalachian Illinois Basin Directors was formed to access the potential and reserves in that area. Bradley J. Field, director of the Division of Minerals Resources of the New York Department of Environmental Conservation, was appointed chairman of the group. The IOGCC, the U.S. Department of Energy (DOE), and Akoya delivered a final draft of the report at the IOGCC Midyear Meeting in Anchorage, Alaska. The comments and changes from the last review were incorporated for the final report entitled "Mature

Region, Youthful Potential: Oil and Natural Gas Resources in the Appalachian and Illinois Basins”. The initial printing of 12,000 copies was distributed through a comprehensive communications plan developed by the IOGCC. The IOGCC publicized the report by submitting a press release to national and local media and IOGCC constituents. The report was distributed to state oil and gas directors; state geologic surveys; state, regional and legislative energy committees; the DOE, and national and local media. It is available on the IOGCC Website. The report was so well received that in January 2006 a reprinting of 6,000 copies was ordered.

The Appalachian Illinois Basin Directors group was involved in all IOGCC midyear and annual meetings and continues to pursue new projects to implement Basin-wide strategies as laid out in “Mature Region, Youthful Potential,” which is attached as *Appendix J*.

North American Costal Alliance (NACA) efforts were focused on the completion of a report that provides a comprehensive inventory of the potential North American offshore oil and natural gas resources that currently are off limits to drilling. The first draft was submitted at the IOGCC Annual Meeting in Jackson Hole, Wyoming, in September 2005. Offshore potential resources described in the report are the mean values of undiscovered technically recoverable resources, defined as “the portion of the hydrocarbon estimated on the basis of geological knowledge and the theory to exist outside known accumulations.” The moratoria study was completed in February 2006 and titled “Untapped Potential.” The published report includes potential resources located offshore Mexico, U.S.A., and Canada. The study included a comparison of areas which are accessible to oil and gas exploration and development with an overlay of areas that presently are off –limits. The IOGCC printed 10,000 copies that were distributed through a comprehensive plan developed by the IOGCC communications department. The IOGCC publicized the report by submitting a press release to national and local media and IOGCC constituents. The report was distributed to state oil and gas directors; state geologic surveys; state, regional, and national oil and gas associations; state governors and their energy advisors; federal and state legislative energy committees; the U.S. Department of Energy; national and local media, and the IOGCC Website. “Untapped Potential” attached as *Appendix K*.

The NACA met at all IOGCC midyear and annual meetings to discuss future projects and lay out a strategic plan for implementation.

Marginal Well Publication -- The IOGCC does an annual survey of the Council of State Regulatory Officials to compile data regarding sales and production, marginal wells, orphaned wells, and training needs. This information helps IOGCC to better evaluate issues in individual states and determine areas in which the IOGCC can use its expertise to assist the states. The IOGCC has been compiling information on marginal or “stripper” oil and natural gas production annually since 1941. The report highlights how vital these wells are to our country’s energy, economic, and national security. The 2006 report was broken into two sections. The first surveyed the number of marginal wells and their production, and the number of marginal wells abandoned. The second section outlined the economic impact of marginal wells. The report was released in October of

2006. Marginal well report results are distributed nationwide to members of federal and state governments, industry, the media, and associations. The report garners media attention each year, and in the fall of 2006 was featured in publications such as the Oil and Gas Journal, American Oil and Gas Reporter, and several state newspapers. Attached as *Appendix L*.

Rocky Mountain Crude Oil Dynamics-In May 2006, former IOGCC Chairman Dave Freudenthal, governor of Wyoming, created a Task Force composed of representatives from Rocky Mountain states to explore crude oil market dynamics in the region that were resulting in domestic crude oil producers receiving lower prices for their production than similar quality oil sold in other parts of the country.

The task force was comprised of individuals from Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming, the province of Alberta. Its' members were representatives of state oil and gas agencies, industry partners, the Federal Energy Regulatory Commission (FERC), the US Department of Energy (DOE), industry associations and other interested parties. The task force evaluated the factors contributing to market dynamics including the impact of asphalt use, increased production in the Rockies, increased production in western Canada, refining capacity and crude oil quality valuation.

The task force's 2007 report, entitled *Rocky Mountain Region Crude Oil Market Dynamics*, included several recommendations for addressing the causes of market volatility that have led to the devaluing or loss of natural resources.

The report identified that the primary contributing factors to the issue were bottlenecks in the Rocky Mountain region crude oil supply chain infrastructure in the pipeline, refinery capacity, and transportation sectors combined with increasing crude oil production are causing market volatility that leads to a devaluing or loss of natural resources.

Barriers to infrastructure expansion include, high investment costs, potential sunk costs, public perception regarding installment, government regulations, and a perception of insecure future demand conditions regarding long-term production capacity and industry growth.

As part of the next steps for achieving the task force's recommendations, The Honorable John Hoeven, Governor of North Dakota, IOGCC Chairman set the date for an industry-wide summit that was held September 4th – 5th in Denver, Colorado. This summit brought together a wide cross-section of the region's crude oil infrastructure involved in crude oil production and refining in this region, from the extraction of the crude oil to its transportation for the purposes of education, dialogue and future planning.

The primary objective of the summit was to foster the wise stewardship of domestic crude oil resources to benefit present and future generations in the Rocky Mountain Region, form a basis for continued future planning and communications and to develop a

baseline model for solving similar problems in other production regions of the United States.

This was accomplished through the development and implementation of the IOGCC Governors' Task Force Crude Oil Market Dynamics Summit, targeted toward components of the regional supply chain and take-away capacity, potential investors, regulatory agencies and governmental entities for the purposes of sharing information, dialogue, and problem-solving. This summit was the first step in answering the Task Force's question, "Who is going to commit to and pay for new infrastructure?" *Rocky Mountain Crude Oil Market Dynamics, Executive Summary Recommendations Appendix M.*

CONCLUSIONS

Numerous projects were completed that are extremely valuable to state oil and gas agencies as a result of work performed utilizing resources provided by the grant during the project period. Information gathered and researched and meetings attended by committees during this cooperative agreement contribute directly to better information sharing among the IOGCC member states. IOGCC will continue to strive for improvements in Regulatory Streamlining and Improvement; Technology, Training and Education; and Resource Assessment and Development that we can share with all oil and gas producing states. Major achievements under this multi-project grant have been the development of a model process for helping states develop benchmarks for the performance of state oil and gas regulatory programs, the establishment of forums for information-sharing among state oil and gas agencies; and establishing a forum for limiting duplication of regulations between states and the U.S. Environmental Protection Agency (EPA).

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APPENDIX

A

Appendix A

EPA - IOGCC MOU Task Force Meeting Agenda

Date: July 27, 2004 **Time:** 11:00 a.m. – 4:00 p.m.

EPA Region 8 Headquarters, Denver, Colorado

- | | |
|---------------|--|
| 11:00 – 11:10 | IOGCC – Introductions and Opening Remarks. |
| 11:10 – 12:30 | IOGCC – Finalize MOU Report on task force accomplishments to be submitted to the IOGCC Chairman and EPA Administrator and recommend MOU continuation. The report needs to be ready to present at the upcoming IOGCC Annual Meeting in Oklahoma City. Review MOU goals and objectives for the renewal of the MOU Task Force.
<i>(Note: Current MOU expires 12/16/04.)</i> |
| 12:30 – 1:00 | Break for Lunch |
| 1:00 – 1:25 | IOGCC – <i>IOGCC CO2 Sequestration Task Force Presentation</i> – Lawrence Bengal, Task Force Chairman |
| 1:25 – 1:50 | EPA – Discussion of “Treatment as States” status for Native American tribal lands and impacts to oil and gas producing states. |
| 1:50 – 2:00 | EPA – Update on Office of Water NPDES Stormwater Phase II exclusion for oil and gas exploration and production activities. What are the Office of Water’s milestones between now and March, 2005. |
| 2:00 – 2:15 | IOGCC/EPA – Status of OPA ’90 responsible party definition and abandoned well sites. Report on EPA-Coast Guard Task Force looking at Responsible Party definition. EPA report on states/IOGCC’s role in working with EPA on the report |
| 2:15 – 2:30 | EPA – Results of inquiry into the success of protocol for implementation of SPCC plans in EPA Region 7. Status of state inspectors being able to receiving EPA SPCC training. |
| 2:30 – 2:45 | EPA – Status of increase in funding provided to states for implementation of UIC programs. Follow up on Rob Lawrence’s comment regarding a Champion within the EPA Office of Water. Up-date on status of GWPC UIC Cost Analysis Report for Class I, II and V Injection Wells. |
| 2:45 – 2:50 | IOGCC – Status of state interest in Resource Conservation Challenge |

2:50 – 3:00	IOGCC/EPA – Status of notification distribution list for upcoming meetings by state and federal agencies other than state oil and gas programs related to oil and gas issues
3:00 – 3:15	EPA – Discussion of EPA Clean Air Act Initiative for natural gas and oil facilities in Region 8 by EPA’s Enforcement group.
3:15 – 3:25	IOGCC – Status of IOGCC/EPA regional meetings
3:25 – 3:40	EPA – Brief on Hydraulic Fracturing Report.
3:40 – 3:50	Wrap-Up of Discussions/future issues
3:50 – 4:00	Summary and closing comments and future 2004 meeting dates.
4:00 p.m.	Adjourn

EPA - IOGCC MOU Task Force Meeting Agenda

Date: October 17, 2004 **Time:** 9:00 am – 1:00 pm
The Renaissance Hotel, Egbert Room, Oklahoma City, Oklahoma

9:00 a.m. **Opening Remarks and Agenda Review**
Christine Hansen

Dona

DeLeon

9:30 a.m. **Review & Approval of Revised Draft** **Robert**
Harms

Annual Report **Michelle**
Hiller Purvis

- Organization and Content
- Specifics: “Key Areas of Concern” and “Consult and Coordinate”
- “Next steps”
- Approval of Annual Report and “Next Steps”
- Audience, release date and venue, circulation

10:30 a.m. **Break**

10:45 a.m. **Renewal of the MOU and Task Force, mechanics and timetable**

11:00 a.m. **Work plan Development**

- **Review and discussion of “Next Steps” in annual report (See attached chart column I)**
- **Subjects of concern (agenda topics) and recommended actions and solutions (See attached chart column II)**
- **Joint EPA-IOGCC activities/training opportunities**
- **Other subjects or activities to include in work plan**
- **Prioritization for future activities**

12:30 p.m. **Wrap-Up Discussion**

- **Steering Committee and Workgroup Assignments**
- **Date and Location for Facilitated Discussion of Work plan**

1:00 p.m. **Adjourn**

EPA-IOGCC MOU TASK FORCE MEETING

THE RENAISSANCE HOTEL, OKLAHOMA CITY, OKLAHOMA

ATTENDANCE SHEET

Sunday, October 17, 2004

<input checked="" type="checkbox"/>	Name (Please Print)	Affiliation	Work Phone	E-Mail Address
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EPA - IOGCC MOU Task Force Meeting Agenda

Date: February 18, 2005 **Time:** 8:00 am – 5:00 pm
EPA Region 6 Headquarters, Dallas, Texas

9:00 a.m.	Opening Remarks and Agenda Review Hansen	Christine
	DeLeon	Dona
9:20 a.m.	MOU Task Force Annual Report Update Harms And Renewal of MOU Michelle Hiller-Purvis	Robert

WHITEPAPER TOPIC DISCUSSIONS

9:30 a.m.	Outreach Strategy/Mechanisms Michelle Hiller-Purvis
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Kevin Bliss

10:00 a.m.	10-Minute Break
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10:10 a.m.	SPCC Inspections Robert Harms
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Michelle Hiller-Purvis

10:35 a.m.	Reg. 8 Air Enforc. Initiative/State Survey Results Hogle	David
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11:00 a.m.	UIC Funding: Partnership with GWPC & ECOS Helms	Lynn
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11:30 a.m.	Hydraulic Fracturing: Plan for Monitoring Issue Anthony Moore
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Kevin

Bliss

12:00 p.m.	Lunch
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1:00 p.m.	City of Denton, Texas EPA Stormwater Grant Lawrence	Rob
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1:15 p.m.	SPCC: Data/Info. To Characterize Small Operators Michelle Hiller-Purvis
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1:45 p.m.	CO2 Sequestration Lawrence Bengal
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Anthony Moore

2:15 p.m. **Tribes: Treatment as States**
 Michael Decker

David

Hogle

2:45 p.m. **10-Minute Break**

2:55 p.m. **Regulatory Status Report**
 Michelle Hiller-Purvis

3:25 p.m. **Joint Training Opportunities**
Harms

Robert

3:55 p.m. **Wrap-Up Discussion**
 Richard Greene

Robert

Harms

- **Steering Committee & Workgroup Assignments**
- **Date and Location Next Meeting**

4:30 p.m. **Adjourn**
 Richard Greene

EPA-IOGCC MOU TASK FORCE MEETING

EPA REGION 6 HEADQUARTERS OFFICES - Dallas, Texas

ATTENDANCE SHEET

Friday, February 18, 2005

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1	Robert Harms	North Dakota	701-225-2841	harmsrbtr@aol.com
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IOGCC MidYear Issues Summit
Anchorage, Alaska

EPA/IOGCC Task Force Meeting
Sunday, May 15, 2005

Draft Final Agenda [Update: 5/2/05]

<i>EPA</i>	9:00am	Welcome and Opening Remarks	<i>Richard E. Greene,</i>
<i>IOGCC</i>		Report from Dallas Working Session	<i>Robert Harms,</i>
<i>Purvis, EPA</i>		Discussion of Proposed Work Plan	<i>Michelle Hiller</i>
		Approach	
	9:30am	Carbon Sequestration IOGCC's Carbon Sequestration Task Force Report	<i>Larry Bengal, IOGCC</i>
		EPA's Geologic Sequestration Workgroup: Report from the First Meeting	<i>David Hogle, EPA</i> <i>Ted Rockwell, EPA</i>
		Opportunities for Collaboration Discussion	<i>All</i>
<i>Purvis, EPA</i>	10:00am	Hydraulic Fracturing EPA's Agreement w/Service Companies	<i>Michelle Hiller</i>
		Discussion: Proposed follow-up activities	<i>All</i>
	10:30am	Characterizing Small Operators For the SPCC Rule	<i>Mark Carl, IOGCC</i>
		Stormwater Rule: Construction	
<i>EPA</i>	11:00am	SPCC Program Congressional Inquiries	<i>Richard E. Greene,</i>

Status Report & Timeline for the National Checklist and Guidance Documents *Art Spratlin, EPA*

The Upstream Sector: Opportunity for Collaboration?
Presentation and Discussion

11:30am **News in Brief:** Brief Remarks and Q & A

☐ The Energy Bill *Michelle Hiller Purvis, EPA*

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☐ Stormwater *Michelle Hiller Purvis, EPA*

☐ EPA Regulatory Agenda *Michelle Hiller Purvis, EPA*

☐ UIC Funding Partnership *Christine Hansen, EPA*

☐ Region 8 Air Enforcement Initiative *David Hogle, EPA*

☐ OPA Reauthorization *Christine Hansen, IOGCC
Allison Herring, IOGCC*

☐ Treatment of Tribes as States *Rob Lawrence, EPA
Mike Decker, IOGCC*

☐ “Navigable Waters” *Ted Rockwell, EPA
Keith Thomas, IOGCC*

12:00pm **Wrap-up and Next Steps**

Adjourn

May 15, 2005 EPA-IOGCC MOU Task Force Meeting In Anchorage, Alaska			
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NOTE: Names in Blue and Red Denote IOGCC and EPA Task Force Members, Respectively

EPA/IOGCC Task Force Meeting
Sunday, September 19, 2005
Jackson Hole, Wyoming
Tentative Agenda as of **August 24, 2005**

- 8:30am **Welcome, Introductions, and Agenda Review**
Bob Harms, IOGCC
Richard Greene, EPA Region 6
- Legislative Highlights: Anthony Moore, EPA
 Christine Hansen, IOGCC
- 8:45am **Treatment As States of Tribes:**
Presentation and Q's and A's
Attorney/Advisor, EPA's Office of General Counsel
- Remarks to address contents of IOGCC Resolution 05.051*
Concerning Treatment as States (TAS) of Tribes.
- 9:15am **EPA's Regulatory Development Process and Consultation**
Requirements: Presentation and Q's & A's
Michelle Hiller Purvis, EPA (OCIR)
- Proposed State Communications Project**
Kevin Bliss, IOGCC
- 9:40am **Updates:**
Diesel Fuel: IOGCC Energy & Environment
 Committee
Carbon Sequestration Risk Assessment Workshop:
 Anthony Moore, OW; Larry Bengal, IOGCC
Region 8 Air Initiative: David Hogle, R8 (Invite: Colorado Air
 Director?)
- 10:00am **SPCC Training Discussion:** Course Content and Who Should
Participate
 Mark Howard, EPA SPCC Program; Art Spratlin, EPA
 Region 7
- SPCC Achieving Compliance:** Discussion and Creation of
Workgroup
- 10:20am **Wrap-up and Next Steps**

10:30am

Adjourn Task Force Session

Special Task Force Sponsored Session Open to all Meeting Participants

Note: Need Separate Meeting Room to Accommodate Larger Audience

10:30am- 12:30pm

Spill Prevention Control and Counter Measures: National Guidance and Checklist

Note: Documents will be available and distributed prior to the meeting.

Presentation and Dialogue:

Mark W. Howard, Chief, SPCC Branch

Office of Solid Waste and Emergency Response

*** EPA/IOGCC Task Force Reserved Topics:**

UIC Funding

Oil Pollution Act: Responsible Parties

EPA-IOGCC MOU Task Force Meeting In Jackson Hole, Wyoming			
Sunday, September 18, 2005			
Participant	Phone No.	Affiliation	Feb. 18, 2005
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NOTE: Names in Blue and Red Denote IOGCC and EPA Task Force Members, Respectively

EPA/IOGCC MOU Task Force Meeting

Agenda

April 6, 2006

EPA Region 8 Office – 999 18th Street, Denver, CO

- 10:00 Welcome, Introductions, and Agenda Review**
Host: Robbie Roberts, Regional Administrator, EPA Region 8
Task Force Co-chair: Bob Harms, IOGCC
Task Force Co-chair: Richard Greene, Regional Administrator, EPA Region 6
- 10:15 Moving the EPA/IOGCC MOU Task Force Forward**
Goal: Identify how to meet the purpose and objectives of the MOU
Richard Greene, EPA Region 6
- 11:00 Proposed Work Plan for 2006**
Goal: Establish clear objectives for the year
Bob Harms (IOGCC)
- 11:45 Issues on the Horizon: General Discussion**
-Agenda for fall meeting to include report out on IOGCC Standing Committees; Task Force session to be after Standing Committee meetings
- Draft Well Information Data Standard
- 12:15 LUNCH**
- 1:15 Legislative Highlights**
Goal: Identify areas requiring follow-up or action
Anthony Moore (EPA OW) and Kevin Bliss (IOGCC)
- 1:30 EPA's Regulatory Development Process and Consultation**
Goal: Improve effectiveness of consultation for EPA and the States
Denise Ney, (EPA OCIR) and Robert Harms (IOGCC)
- 2:00 Proposed State Communications Project**
Goal: Identify mechanisms to improve effectiveness of communications between state agencies
Robert Harms and Kevin Bliss (IOGCC)
- 2:15 Oil and Gas Air Action Plan**
Goal: Obtain state input and counsel for implementation
Carol Rushin, Assistant Regional Administrator, EPA Region 8

Rob Lawrence, Energy Advisor, EPA Region 6

2:30 **Carbon Capture and Storage**

Goal: Provide coordination between EPA and IOGCC to avoid conflict

Risk Assessment Workshop: Next Steps

Anthony Moore (EPA OW) and Larry Bengal (IOGCC)

Status Update on EPA Activities

Anthony Moore (EPA OW)

Overview of DOE Carbon Sequestration Project and IOGCC Grant

William O'Dowd (National Energy Technology Laboratory/DOE)

Update on IOGCC Grant Application to DOE

Christine Hansen (IOGCC)

3:00 **Spill Prevention, Control, and Countermeasures**

Goal: Enhanced understanding of program, roles, and goals

Craig Matthiessen (EPA OSWER)

- Joint Training Discussion: Course Content, Topics and Participants
 - Status of guidance; comments made by state regulatory programs
 - Achieving Compliance
- Goal: Determining proactive strategy, brainstorming how we can work together*

3:30 **Wrap-up and Next Steps**

Next Meeting Date: October 16, 2006; Austin, Texas

3:45 **Adjourn**

*** EPA/IOGCC Task Force Reserved Topics:**

UIC Program Funding

Oil Pollution Act: Definition of Responsible Parties

Treatment as States

AGENDA
ENVIRONMENT AND SAFETY COMMITTEE SESSION
IN CONJUNCTION WITH THE IOGCC/EPA MOU TASK FORCE
IOGCC ANNUAL MEETING
Omni Austin Hotel Downtown
Austin, Texas
Capital Ballroom
Monday, Oct. 16, 2006
3:45 p.m. – 5:30 p.m.

- 3:45 **Welcome, Introductions, and Agenda Review**
Task Force Co-chair Richard Greene, Regional
Administrator, EPA Region 6
Task Force Co-chair: Bob Harms, IOGCC
- 3:55 **Review Work Plan for 2006**
Goal: Establish clear objectives for the year
Denise Ney (EPA OCIR)
- 4:10 **Issues on the Horizon: General Discussion**
-IOGCC report on IOGCC Standing Committees;
-EPA report issues
- 4:20 **Overview of EPA's Regulatory Development Process and Consultation**
Goal: Improve effectiveness of consultation for EPA and the States
Denise Ney, (EPA OCIR) and Robert Harms (IOGCC)
- 4:25 **Carbon Capture and Sequestration**
IOGCC: status of IOGCC Task Force work effort
(Larry Bengal)
EPA: status of EPA work effort—(Anthony Moore)
- 4:45 **Maximizing Results of the Task Force**
- 5:10 **Wrap-up and Next Steps**
Meeting Date: Dallas, Texas January/February 2007(tentative)
- 5:15 **Storm water Presentation**
"Reasonable and Prudent Practices for Stabilization (RAPPS)"
Marilyn Fish, Director of Environmental Health and Safety, EOG Resources
- 5:30 **Adjourn**

Agenda items in other venues: 10/16/06:

MOU Renewal and report; (4:00 Oct.15, 2006 venue tbd)

Air Emissions Reduction Initiative at Oil and Gas Facilities

- Council of State Regulatory Officials: Report on Region Air Action Plan and context of Eco-region Initiative.
- IOGCC Energy Research, Resources and Technology Committee: presentation on infrared camera technology used in air initiatives

*** EPA/IOGCC Task Force Reserved Topics:**

UIC Program Funding
Oil Pollution Act: Definition of Responsible Parties
SPCC Achieving Compliance
SPCC Joint Training Sessions
Treatment as States
State Communications Project

Storm Water presentation: practices, and recommendations following EPA Act
2005 *(Tentative)*
IOGCC Environment and Safety Committee

AGENDA

IOGCC/EPA MOU Task Force Meeting

Sunday, May 6, 2007

8:30 a.m. – 12:30 p.m.

Marriott Grand Hotel

Point Clear, Alabama

Magnolia 1 Room

ALL

8:00	Welcome, Introductions and Agenda Review	Bob Harms, IOGCC and Robbie Roberts, EPA
8:10	Status Report on Renewal of the MOU	Bob Harms, IOGCC and Randy Kelly, EPA
8:20	Air Office Guidance: Definition of Aggregation of Oil & Natural Gas Development	Bill Harnett, EPA
8:45	State Communications Project: Update on IOGCC and ECOS Collaboration	Kevin Bliss, IOGCC
9:00	Carbon Capture and Storage: Update	
	A. Status of EPA Activities	Anthony Moore, EPA
	B. Overview of DOE Carbon Sequestration Project	Larry Bengal, IOGCC
9:30	Biannual Progress Report from the Task Force	Bob Harms, IOGCC
9:45	Discussion of a Work Plan for 2007-2008	Randy Kelly, EPA [and Christine Hansen]
10:45	Issues on the Horizon	
11:00	A. SPCC Regulations: Status of Development	Rob Lawrence, EPA
11:45	B. EPA v. Massachusetts	Position Papers Distributed
12:00	New Business (including Regulatory Consultation)	Robbie Roberts, EPA and Bob Harms, IOGCC
12:30.	Adjourn	

AGENDA
IOGCC/EPA MOU TASK FORCE
IOGCC ANNUAL MEETING
Omni Royal Orleans Hotel
New Orleans, Louisiana
Toulouse Room
Tuesday, Sept. 25, 2007
7:30 a.m. – 9:30 a.m.
7:30 – Continental Breakfast

1. **Call to Order** Robert Harms
2. **Welcome and Introductions** Richard Greene/Robert Harms
3. **Historical overview of MOU Task Force** Greene/Harms
4. **Office of Air and Radiation Presentation:** Bill Harnett, EPA
Status of NSR Minor Permitting Program on Tribal Lands
5. **Office of Air and Radiation Presentation:** Bill Harnett, EPA
Status of NSR Minor Permitting Program on Tribal Lands
6. **Office of Water Presentation:** Anthony Moore, EPA
Effluent Limitation Guideline for Coalbed Methane: Outreach and Survey
7. **Office of Solid Waste and Emergency Response Presentation:** Craig Matthiessen, EPA
SPCC Rule Status and Potential Changes
Follow up discussion regarding IOGCC/EPA Cooperation on SPCC issue after Environment and Safety Committee Presentation by Craig Mattheissen , U.S. EPA, Monday, Sept. 24
8. **Office of Air and Radiation Presentation:**
Offer to Work on Air Emission Factors for Oil and Natural Gas Production
Follow up discussion regarding IOGCC/EPA Cooperation on Air Emission issue after Environment and Safety Committee Presentation by Bill Harnett , U.S. EPA, Monday, Sept. 24
9. **Louisiana Department of Environmental Quality and** Rob Lawrence, EPA,
Louisiana Department of Natural Resources Presentation: Introducing Presenter TBD
Environmental Results Program Applied to Oil and Gas Production Facilities
10. **IOGCC Update on the ECOS/IOGCC Forum in Idaho** Kevin Bliss, IOGCC
11. **Geologic Sequestration:**
Update on IOGCC/DOE activities Larry Bengal, IOGCC
Update on EPA CO₂ Work Group Anthony Moore, EPA
12. **Work plan review/ finalization** Richard Greene/Robert Harms
13. **Upcoming Report** EPA Task Force Member
14. **Other Issues on the Horizon:**
EPA v. Massachusetts Robert Harms
SPCC Regulations/Compliance
Methane Measurements; Plans for Future
15. **Scheduling of next task force meeting** Task Force


16. Adjournment

Harms

APPENDIX

B

2007



Investments in Energy Security

state incentives to maximize oil and gas recovery

an official publication of the Interstate Oil and Gas Compact Commission
in partnership with The Energy Council

ABOUT THE COMMISSION

The Interstate Oil and Gas Compact Commission is a multi-state government agency that promotes conservation and efficient recovery of our nation's oil and natural gas resources while protecting health, safety and the environment.

Representing the governors of 38 states, the IOGCC serves as a forum where state, federal and industry officials can meet to develop sensible solutions to common problems. The Commission's ability to find common ground is unmatched by any other entity dealing with petroleum issues.

The IOGCC also effectively develops regulatory guidance documents and model legislation; conducts studies related to resources, production, research, development and emerging environmental concerns; and provides training and education for industry, the regulatory community, key leaders and the general public.

For more information visit www.iogcc.state.ok.us or call 405.525.3556.

Introduction

The Interstate Oil and Gas Compact Commission, with funding from the U.S. Department of Energy, compiles this annual catalogue of oil and gas incentive programs to assist government entities in developing and enhancing new and existing oil and natural gas incentives. This report is also intended to assist legislators and regulators craft new incentives and to also communicate states' actions with members of Congress, federal agency officials and the oil and gas industry.

Throughout the report, the term “incentive” is used more broadly than in traditional context. The scope of the report is not limited to tax incentives, but includes any program that assists oil and natural gas producers in the efficient recovery of petroleum resources while maintaining health and environmental protection.

State incentive programs are varied, including tax relief for low-volume, economically marginal wells or idle wells brought back into production; petroleum information services provided to the oil and gas industry; and incentives to develop and use new technologies that increase the efficiency of extraction. These programs vary in quantifiable effectiveness. While many have proven successful, over the years some incentives have been disappointments.

It is important to note that even when a particular incentive program is not extensively used by industry or judged successful based on economic rewards to the state, its adoption can strengthen the interests of oil and natural gas producers considering expanding in that state.

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ALABAMA

Eastern Gulf Salt Tectonics Project, Geological Survey of Alabama

Investigators are conducting a research program called "Geometry and Evolution of Mesozoic-Cenozoic Salt Structures in the DeSoto Canyon and Eastern Mississippi Interior Salt Basins." This program is 50% supported by federal funds (Minerals Management Service) and 50% supported by the Geological Survey of Alabama.

Effective date: October 2001

Goal: To assess the structural geometry and hydrocarbon trapping mechanisms in onshore areas of the Mississippi interior salt basin in southwest Alabama and offshore areas of the DeSoto Canyon salt basin in state and federal waters adjacent to Alabama and Florida.

Impact: Results indicate that structural geometry in the study area is highly varied and includes peripheral faults, salt rollers, large salt pillows and salt diapirs. In onshore areas, hydrocarbons are produced mainly from Jurassic carbonate rocks in footwall uplifts with large salt pillows and salt diapirs. In offshore areas, by contrast, proven production comes from Jurassic eolian sandstone above salt rollers and above large salt pillows. The peripheral faults and salt diapirs of the DeSoto Canyon salt basin are largely unexplored, indicating that significant reservoir potential remains in the eastern Gulf of Mexico.

New Wells

Oil and gas wells permitted on or after July 1, 1996, and before July 1, 2002, except a replacement well for a well for which the initial permit was issued before July 1, 1996, are eligible for a privilege tax reduction. The rate reduction of 4% is applicable for a period of five years commencing with commercial production, after which the 6% rate applies.

Citation: Act 96-277, House Bill No. 54; amends Ala. Code §§ 40-20-2(a) and 9-17-25 (1975)

Effective date: July 1, 1996

New Wells

Privilege tax is reduced from 8% to 6% for:

- Discovery wells;
- Development wells when drilling commenced within four years of the completion date of the discovery well and oil or gas is produced from a depth of 6,000 feet or greater;
- Development wells when drilling commenced within two years of the completion date of the discovery well, and oil or gas is produced from a depth of less than 6,000 feet.

This privilege tax reduction for new wells applies only to wells permitted after July 1, 1984, and is to be applied for five years from the date production begins from these wells.

Citation: Ala. Code § 40-20-2(a)(4) (1975)

Effective date: July 1, 1984

Unit Operations

A reduction of the percentage required for ratification of a unit agreement was enacted by the legislation. This legislation reduces the percentage from three-fourths to two-thirds for ratification of a unit agreement under the terms of the allocation formula established by the State Oil and Gas Board and for ratification of an addition to the unit area. There has been no effectiveness study conducted.

Citation: 2000 Acts of Alabama 1714
Effective date: Sept. 1, 2000
Goal: To encourage enhanced recovery.
Active supporters: State Oil and Gas Board

Royalty Payment

Increases the minimum royalty payment threshold to \$100.

Citation: S.B. 92; Act 99-396
Effective Date: June 1999

Marginal/Stripper Wells

Privilege tax is reduced from 8% to 4% of value on wells producing 25 barrels of oil or less per day, or 200 Mcf per day of natural gas.

Citation: Ala. Code §§ 40-20-1 and 2(a) (1975)
Effective date: 1985

Enhanced Recovery

Severance tax is reduced to 6% of value on any oil well produced or developed from a qualified enhanced recovery project. The State Oil and Gas Board of Alabama approves the projects and calculates “incremental production” by determining a base production rate.

Incremental production for the project is production over that base rate. Incremental natural gas from a qualified enhanced recovery project is taxed at a reduced rate of 4%.

Citation: Ala. Code § 40-20-1 § 40-20-2(a)(2) (1975)
Effective date: May 1, 1985

Offshore Deep Wells

A privilege tax reduction to 4% for offshore wells permitted after July 1, 1998, and a borehole depth greater than 18,000 feet. A privilege tax reduction to 6% for offshore wells permitted before July 1, 1988, with a borehole depth greater than 18,000 feet. The wells must be drilled offshore in state waters. All new wells drilled after July 1, 1988, qualify for a privilege tax reduction to 6%.

Citation: Ala. Code § 40-20-2(a)(5)(1975)
Effective date: July 1, 1988; no sunset

Discovery Wells

Privilege tax reduction for discovery wells found after July 1, 1984. A tax reduction of 6% for qualifying discovery wells for up to five years from production date. Replacement wells for discovery wells also qualify for remainder of the five-year period. All new wells drilled after July 1, 1984, qualify for a privilege tax reduction to 6%.

Citation: Ala. Code § 40-20-2 (1975)
Effective dates: July 1, 1984; five years from production date

Core and Sample Library, Geological Survey and State Oil and Gas Board

The Geological Survey of Alabama maintains a core and well sample library that includes cuttings from 4,000 oil and gas wells, core from 1,700 oil and gas wells, cuttings from 2,800 water and stratigraphic test wells and core from 350 industrial mineral core holes.

Rules and regulations of the State Oil and Gas Board require that exploration companies submit cores and drill cuttings following the completion of wells. Rule 400-1-3-.10 of the Code of Alabama 1975 states in part that “a complete set of cuttings, correctly labeled and identified as to depth, shall be filed with the Board within 30 days from the time of completion of any well unless otherwise approved by the supervisor. If cores are taken, a complete set of cores, either whole or at least quarter slabs, correctly labeled and identified as to depth, shall be filed with the Board within six months from the time of completion of any well unless otherwise approved by the supervisor.” The facility has four viewing rooms for use by operators and researchers.

Goals: To encourage oil and gas production by making useful data available to producers. Counteract the loss of infrastructure in the independent industry.

Effective Dates: Not Applicable

ALASKA

Acreage Limitation Increase

Aggregate state land acreage holding increased from 500,000 to 750,000 acres on all land other than tide and submerged land, of which not more than 500,000 acres may be located north of the Umiat baseline.

Citation: Alaska Stat. 38.05.140(c) as amended

Effective date: June 13, 2003; End date: Open end

Goal: To increase the opportunity of exploration companies to assemble acreage blocks outside of the primary North Slope producing area.

Active supporters: Former Gov. Frank Murkowski, Division of Oil & Gas, AOGCC and Legislators

Statewide Royalty Reduction

Gives Commissioner of Natural Resources right to determine royalty rates for uneconomical oil and natural gas resources - including never produced, shut in or about to be shut in.

Citation: Alaska Stat. 38.05.180 as amended

Effective date: June 12, 2003; End date: Open end

Goal: Bring known marginal resources into production and temporarily extend the life of production that is about to be abandoned.

Active supporters: Cook Inlet producers, Former Gov. Frank Murkowski and Legislators

Gas Exploration and Development Tax Credit

Establishes a 10% exploration and development incentive tax credit for operators and working interest owners directly engaged in the exploration and production of natural gas south of the 68 degree north latitude.

Citation: Alaska Stat. 43.20 as amended

Effective date: May 20, 2003; End date: Ongoing

Goal: Promote exploration and development of natural gas resources for the in-state market

Active supporters: Legislators

Oil and Gas Exploration Tax Credit

Creates a 20% tax credit for certain exploration drilling and geophysical costs for activities conducted more than three miles from an existing well or 25 miles beyond the boundary of an existing unit with an approval plan of development. Maximum tax credit is 40%.

Citation: Alaska Stat. 43.55.025

Effective date: Sept. 9, 2003; End date: July 1, 2007

Goal: Stimulate exploration activity in areas near infrastructure.

Active supporters: Former Gov. Frank Murkowski and Legislators

Areawide Lease Sales

Provide an established time each year that acreage within a geographical region will be available for lease. This will increase the number of lease sales conducted by the state to four per year.

Effective date: Jan. 1, 1997 End date: Ongoing

Impact: The first North Slope areawide lease sale brought \$52 million in bonus bids, making it the fourth-largest sale in state history. Two North Slope Foothills areawide sales have resulted in the largest amount of acreage ever leased in state sales - nearly 2 million acres. The state has held areawide lease sales every year since 1998. North Slope and Beaufort Sea areawide sales occur annually in October. Cook Inlet and North Slope Foothills areawide sales occur annually in May.

Goal: Allows companies to develop their exploration strategies and budgets.

Active Supporters: Industry, Former Gov. Tony Knowles, Legislature

Shallow Gas Leasing

Over-the-counter leases are available specifically for the development of natural gas from coal seams and shallow gas sands from a field if a part of the field is within 3,000 ft. of the surface. There is an application fee of \$5,000 and annual rental payments are kept at \$1 per acre. A reduced royalty of 6.25%, rather than 12.5%, applies if the shallow gas is sold to a local utility. The royalty reduction applies only if the shallow gas is not in direct competition with higher royalty, deeper gas.

Citation: Alaska Stat. 38.05.177

Effective date: Adopted July 1996; no sunset

Goal: To locate local sources of gas that can be delivered to consumers in remote areas at less cost than alternative energy sources.

Impact: The state held its first noncompetitive Shallow Gas Lease Offering on February 29, 2000. The state has issued 107 Shallow Gas leases covering approximately 504,374 acres and has two applications for multiple leases pending.

Active Supporters: Industry, native corporations and rural utilities

Exploration License Program

The Exploration License Program (ELP) offers large unexplored areas of Alaska for exploration. The license confers the exclusive right to explore, for up to 10 years, areas between 10,000 and 500,000 acres in size. Applicants bid on the license, and the applicant willing to spend the most on exploration wins the license fee. No licensee may hold more than 2 million acres under license at any given time.

Citation: Alaska Stat. 38.05.131-134

Effective date: 1996; no sunset

Goal: To encourage exploration in Alaska's interior and unexplored areas (not applicable to the Alaskan North Slope or Cook Inlet, which are known oil and gas provinces).

Impact: The state has issued two Exploration Licenses. One in the Copper River Basin and one in the Nenana Basin and currently has two licenses pending. Total land under license is 903,638 acres.

Economic Limit Factor

The severance tax rates for oil and gas are reduced by a field's Economic Limit Factor (ELF). During the life of a field, production income diminishes while some operating costs remain fixed. At some point, total operating costs, royalties and production taxes, will exceed gross revenue and the field may be shut in. This is called the economic limit. As production diminishes, the tax rate on the field also decreases. The ELF provides for lower tax rates based on daily per well production and the productivity of the field.

Citation: Alaska Stat. 43.55.012

Effective date: 1989; no sunset

Goals: To keep fields in production as they decline and encourage operators to drill development wells.

Impact: Severance tax rate is effectively zero for the smaller oil fields in Alaska.

Exploration Incentive Credits

Operators drilling on state lands may earn Exploration Incentive Credit (EIC) based on footage drilled and the region in which drilling takes place. Credits may be as high as 50% of eligible costs. Geophysical work qualifies for the EIC if that work is performed within two years prior to a lease sale. The geophysical data must be made public after the sale.

Citation: Alaska Stat. 38.05.180(i)

Effective date: Nov. 9, 1979

Goal: To encourage exploration on state land.

Impact: Twenty exploratory wells qualifying for credit have been drilled on state leases; credits totaling \$54.7 million have been issued. The state has received no requests for the geophysical EIC.

The Commissioner of Natural Resources may grant an EIC for exploratory drilling, stratigraphic test well drilling, and for geophysical work on other lands within the state (this includes federal as well as private land owned by Native Alaskan regional corporations formed under the Alaska Native Claims Settlement Act). Wells must be drilled three or more miles from another well or within three miles of an oil or gas well when the commissioner finds that they are drilled in separate exploration targets. Credits may be as high as 50% for wells drilled on federal land and 25% for wells on private land. The amount of drilling credits is based on feet drilled. Exploration data remains confidential for two years. The amount of credit may not exceed \$5 million per project, and the total of credits may not exceed \$30 million.

Citation: Alaska Stat. 41.09.010

Effective dates: July 7, 1994, through July 7, 2007

Goals: To encourage exploration in remote parts of the state and to provide a means for the state to obtain exploration data from state, federal and certain private lands.

Active Supporters: Industry

Cook Inlet Discovery Royalty

Permits the granting of discovery royalty for wells in the Cook Inlet Sedimentary Basin that have discovered oil or natural gas in a previously undiscovered oil or natural gas pool, provided the wells are capable of producing in payable quantities. The discovery royalty is set at 5% for 10 years following the date of discovery.

Citation: Alaska Stat. 38.05.180(f)

Effective date: July 1996; End date: Ongoing

Goal: To encourage exploration for oil and natural gas in the Cook Inlet.

Active Supporters: Alaska Legislature, small Cook Inlet exploration and production firms

Stranded Gas Pipeline Carriers

Former Gov. Knowles signed CSHB 290 into law, effective August 9, 2000. This law restricts common carrier status of a North Slope natural gas pipeline to intrastate transportation.

Citation: CSHB 290

Effective date: Aug. 9, 2000

Goals: To free export shippers of North Slope natural gas from the common carrier requirement to accept all tendered volumes of natural gas.

Impact: The guarantee of pipeline capacity for an LNG export project is an incentive for developers of natural gas that is now stranded on the North Slope.

Production Tax Based on Net Value of Oil and Gas

Net value is the value at the wellhead, less all qualified lease expenditures, including capital and operating costs. The capital expenditures receive a 20% credit.

Citation: SCS CSHB 2001

Effective date: Waiting for transmittal to the Governor for her signature, Nov. 26, 2007

ARIZONA

Property Tax Reduction

The Property Tax Reform and Reduction Act, passed by the 42nd Legislature in July 1996, reduced the property tax assessment ratio for all real and personal property used by producing oil, gas and geothermal interests to 28% of full cash value from 100%. The tax rate will decrease an additional 1% per year until holding at 25% in 1999 and thereafter.

Citation: A.R.S. 42-15001

Effective date: 1996 tax year; no sunset

Goals: To provide tax equity for oil, gas and geothermal interests, and to encourage leasing and exploration activity.

Impact: The tax assessment ratio reduction is effective in achieving tax equity.

Active supporters: Paul Slayton, Mountain States Petroleum; John Somers, High Plains Petroleum; Arizona Oil and Gas Conservation Commission; Arizona Geological Survey

ARKANSAS

Marginal Wells

Severance tax is reduced from 5% to 4% for marginal wells, which are defined by the state as wells, which produce an average of less than 10 barrels of oil per day (BOPD) during any calendar month.

Effective date: Feb. 25, 1983; no sunset

Act 1093 of 1995 provides severance tax relief to certain projects designed to increase oil production in Arkansas:

1. Idle Wells

Inactive oil wells (no production for 12 consecutive months) that are restored and re-established as producing wells are exempted from severance taxes for 10 years from the date of renewed production.

Citation: Ark. Stat. 15-72-1002

2. Idle Fields

An inactive oil field that is later returned to production shall be exempted from severance taxes for oil produced from all zones, horizons and formations that were once productive but have ceased to produce.

Citation: Ark. Stat. 15-72-1002

3. Enhanced Oil Recovery

Enhanced recovery projects approved by the Oil and Gas Commission are entitled to a 50% reduction in severance taxes for the incremental volume of oil attributable to the project.

Citation: Ark. Stat. 15-72-1001

4. New Technologies

Incremental production due to application of new research technologies approved by the Oil and Gas Commission is exempt from severance tax.

Citation: Ark. Stat. 15-72-1003

Effective date of Act 1093: April 10, 1995; no sunset

Goals: To provide an incentive to continue production from wells that have reached their economic limit, to encourage reestablishment of production from idle wells and to encourage initiation of enhanced recovery activities to maximize recovery of oil.

Impact: Because few operators have taken advantage of this program, it has been only moderately effective.

Discovery Gas Wells

The volume for discovery gas wells was increased from 50% to 75% of Absolute Open Flow. This change affects only newly discovered fields or zones discovered in existing fields that are deeper than any previous production in the field.

Citation: Arkansas Amendment to Rule D-16, Order Reference No. 74-94

Effective date: Oct. 25, 1994; no sunset

Goal: To encourage exploration for and discovery of new gas sources in the Arkoma Basin.

Impact: No new discoveries have been made since the adoption of this rule change.

Active supporters: SEECO, Inc. (filed the petition for the amendment), Thomas C. Mueller, and Samson Resources Company

Financial Responsibility

Amendment to an oil and gas rule replaced the operator financial assurance requirement for existing operators of oil wells only, with an annual well fee, which provides funding for the newly adopted Abandoned and Orphan Well Fund. New operators of oil wells must still maintain a bond for two years and operators of gas wells must still maintain bonds for the life of the well.

Citation: Amendment to Rule B-2.

Effective date: January 2006, no sunset

Goal: To increase oil exploration and drilling activity in Arkansas and provide a funding mechanism for the Abandoned and Orphan Well Fund.

Impact: Increased oil exploration and funding for state plugging program

Active supporters: Oil and gas operators, Arkansas Oil and Gas Commission

Services

Severance tax credit for saltwater disposal costs is available for production from wells that produce both oil or gas and saltwater. Costs include depreciation of cash investment, maintaining and improving the system, costs of services, labor, supplies, utilities and other operating expenses.

Citation: Ark. Code Subchapter 2, 26-58-200 through 211

Effective date: June 11, 1969; no sunset

CALIFORNIA

Transfer of Pipeline Right of Way

This law allows a utility to transfer easements and right of ways associated with a section of gathering pipeline to an individual producer or a cooperative of producers.

Citation: AB 1234

Effective date: Signed into law, September 2002

Goals: To facilitate the transfer of gas gathering systems.

Active supporters: Assemblyman Anthony Peschetti, California Independent Petroleum Association, California Natural Gas Producers Association and Industry

Active, Idle and Orphan Wells

In response to the growing number of idle and orphan wells, bonding levels for active and long-term idle wells and idle well fees were increased to provide more financial assurance and more funding to plug existing orphan wells. Such resources are needed to cover costs the Department of Conservation, Division of Oil, Gas and Geothermal Resources incurs for orphan well plugging and abandonment, and remediation of hazardous conditions. In addition, operators can provide idle well management options in lieu of the above bonding and fee requirements. The division's orphan well plugging fund doubled to \$1 million a year beginning July 1, 1999, before dropping back to \$500,000 per year commencing July 1, 2010. The additional funds will help eliminate the state's current orphan well inventory.

Citation: §§ 3008, 3202, 3204, 3205, 3205.5, 3206 and 3258 Public Resources Code

Effective date: Jan. 1, 1999

Goals: To provide funding for the state to plug and abandon orphan wells, encourage idleness management and eliminate environmental and safety hazards.

Idle and Orphan Wells

California provides a 10-year abeyance of the assessment on oil and gas produced from orphan wells and wells that have been idle for five or more years when they are returned to productive status. Furthermore, the State Oil and Gas Supervisor may permit an operator to evaluate the economic viability of

an orphan well for 90 days without having to provide bond coverage or assume plugging responsibility for the “adopted” orphan well.

Citation: § 3238, Public Resources Code

Effective date: Jan. 1, 1997; no sunset

Goals: To resume production from idle and orphan wells, reduce the state’s orphan well-plugging costs, increase the energy supply, eliminate environmental and safety hazards, create tax revenue and jobs.

Impact: Positive response; nearly 3.2 million barrels of oil and 20.2 million Mcf were exempted from the oil and gas assessment for 2005.

Services

Natural gas used on-site for pressure-maintenance or other producing operations is exempt from assessment.

Used for repressuring or reinjection: 29,133,590 Mcf

Natural Gas vented and flared: 2,120,131 Mcf

Natural Gas used as fuel on lease: 65,706,556 Mcf

Citation: § 3403, Public Resources Code

Effective Date: Stats. 1976

COLORADO

Marginal/Stripper Wells

Oil and gas income from “stripper wells,” i.e., wells that produce an average of 15 barrels or less of oil per producing day or 90,000 cubic feet of gas per producing day, is exempt from severance tax (stripper well threshold levels increased effective Jan. 1, 2000). A tax credit is available for 87.5% of ad valorem tax.

Citation: Colo. Rev. Stat. § 39-29-105

Effective date: Jan. 1, 1985; no sunset

Active supporters: The Rocky Mountain Oil and Gas Association (RMOGA) drafted and supported this legislation. In addition, the Colorado Oil and Gas Association (COGA) supported the legislation to increase the stripper well threshold levels for purposes of severance tax exemption.

Levy Reduction and Fee Eliminations

In an effort to encourage more effective land and soil reclamation, rules were promulgated to address concerns related to permitting, surface owner notification, site preparation and interim and final reclamation. Elimination of 0.2 mills of environmental response fund levy, all drilling permit fees, re-

completion permit fees, pit and other environmental permit fees, change of operator fees, hearing fees and reduction in conservation fund levy.

Citation: Reclamation Rules (300-Series, 800-Series, 1000-Series, 1100-Series)

Tax Offset

Severance taxes in Colorado are imposed on up to 5% of the gross income at the wellhead, with a credit granted for a portion of ad valorem taxes paid. The net result is approximately a 1% tax rate on gross production. When the local property taxes (ad valorem taxes which are assessed based on 87.5% of the value of production) are above 5.7% they completely offset state severance tax obligation. Only five of the 30+ oil and gas producing counties in Colorado have property taxes below 5.7%, and consequently state severance tax is only effectively required to be paid in those five counties. There is effectively no state severance tax obligation in the other 25+ oil and gas producing counties.

Effective date: January 1, 1978; no sunset

Secondary/Tertiary Recovery

Oil and gas leasehold and lands employing secondary/tertiary recovery or recycling projects are assessed at 75% of the annual gross production value.

Citation: Colo. Rev. Stat. § 39-7-102(2)(a) and (b)

Effective date: Jan. 1, 1978; no sunset

Goal: To conserve and avoid waste of oil and gas.

Impact: RMOGA believes this incentive has increased the efficiency of oil recovery through the application of secondary and tertiary recovery and recycling techniques.

Active supporters: RMOGA drafted and supported this program

Prohibition Against Additional Taxes

Municipalities and counties may not consider oil and gas wells and their related facilities as a business or occupation for the purpose of imposing an occupational privilege tax.

FLORIDA

Exemptions for New Fields, Old Wells and Shut-in Wells

This incentive encourages producers to drill wells in new fields, rework old wells and open shut-in wells by granting exemptions from tax on production from these type wells for a period of four to five years.

Citation: Fla. Stat. Title XIV, § 211.027

Effective dates: July 1, 1997; ends 48 - 60 months after start date; repealed after June 30, 2007

Goal: To encourage and increase oil production.

Active supporters: Florida Independent Petroleum Producers Association

Deep Wells

Oil or gas produced after July 1, 1997, from wells at least 15,000 feet deep is exempt from production taxes for 60 months after completion date. No new exemptions will be granted after June 30, 2002.

Citation: Fla. Stat. Title XIV, § 211.02, and Chapter 86-178, Laws of 1986
Effective dates: July 1, 1996, repealed after June 30, 2007
Goal: To encourage and increase oil production.
Active supporters: Florida Independent Petroleum Producers Association

New Wells

Production from new oil or gas wells in an existing field established before July 1, 1997, is exempt from severance taxes for 48 months after completion. No new exemptions granted after June 30, 2002.

Citation: Fla. Stat. Title XIV, § 211.02, and Chapter 86-178 (1986)
Effective dates: July 1, 1996; repealed after June 30, 2007
Goal: To encourage and increase oil production.
Active supporters: Florida Independent Petroleum Producers Association

New Fields

Production from oil or gas wells drilled in a new field after July 1, 1997, is exempt from production taxes for 60 months after completion.

Citation: Fla. Stat. Title XIV, § 211.02, and Chapter 86-178 (1986)
Effective dates: July 1, 1996; repealed after June 30, 2007
Goal: To encourage and increase oil production.
Active supporters: Florida Independent Petroleum Producers Association

Marginal/Stripper Wells

Severance tax is reduced from 8% to 5% for oil wells producing less than 100 BOPD. Stripper gas is taxed at \$0.12 Mcf.

Citation: Fla. Stat. Title XIV, § 211.02, and Chapter 86-178 (1986)
Effective date: July 1, 1986; no sunset

Horizontal Wells

Production from horizontal wells drilled after July 1, 1997, is exempt from severance taxes for 60 months after the completion date. No new exemptions granted after June 30, 2002.

Citation: Fla. Stat. Title XIV, § 211.027
Effective date: Repealed after June 30, 2007
Goal: To encourage and increase oil production.
Active supporters: Florida Independent Petroleum Producers Association

Tertiary Recovery

The severance tax rate is reduced from 8% to 5% for incremental production attributable to a tertiary recovery project.

Citation: Fla. Stat. Title XIV, § 211.02, and Chapter 86-178
Effective dates: July 1, 1996; repealed after June 30, 2007
Goal: To encourage and increase oil production.
Active supporters: Florida Independent Petroleum Producers Association

Exemption for On-site Use of Production

Oil and gas produced and used on-site are exempt from severance taxes.

Citation: Fla. Stat. Title XIV, § 211.027 (1)

Effective date: July 1, 1996

Goal: To encourage and increase oil production.

Active supporters: Florida Independent Petroleum Producers Association

ILLINOIS

Crude Oil Marketing and Education Act

This voluntary program is modeled after the Oklahoma Energy Resources Board. A tax of 1/10th of 1% of gross revenue of crude oil sales is collected into a fund. One-half of the fund is dedicated to abandoned oil field site cleanup and the remainder funds energy education in public schools.

Effective date: July 1, 1998

Goal: To increase awareness of energy and oil issues among the general public, especially among school age children, and to clean up abandoned production sites.

Active supporters: IOGA (Note: Illinois does not have severance tax on oil or natural gas production)

KANSAS

Unitization

K.S.A. 55-1316 changed the definition of “pool” as it relates to the underground accumulation of oil and gas. This statute change expanded the definition of a “pool” to include “one or more natural reservoirs that are pressure connected.” This statutory change now allows for unitization in pools that have commingled production from more than one single reservoir due to pressure communication within the well bore. Additionally, K.S.A. 1317 provides that if at least 90% or more of the working interest owners approve, in writing, a contract for the unit operations of a pool or part of a pool, then the unit operations becomes effective without application to or order by the Kansas Corporation Commission. These statutes are part of Article 13 of Chapter 55 of the Kansas Statutes Annotated and amendments thereto.

Effective date: April 21, 2004

Goal: To allow the right of unitization of certain commingled pressure communicated reservoir(s) within a common well bore. It also allows the establishment of voluntary unitization operations when at least 90% of the working interest owners, ratify in writing, establishing such unit operations without KCC application or order of approval.

Active supporters: Representatives of the State Energy Resource Coordination Council, Kansas Corporation Commission, Kansas Independent Oil and Gas Association, and BP America Production Company

Venting and Flaring of Gas

This statute change will allow venting or flaring of gas from natural gas wells (including gas from coal seams) when approved by the Kansas Corporation Commission. The venting or flaring of gas has always been associated with waste and, therefore, was not allowed except for associated casing head gas from oil wells.

Citation: K.S.A. 55-102

Effective date: June 13, 2002

Goal: To allow the limited venting or flaring of natural gas from both traditional and coal seam gas reservoirs for periods permitted by the KCC.

Active supporters: Kansas Independent Oil and Gas Association, Kansas Petroleum Council, and the Eastern Kansas Oil and Gas Association

Tests of Gas Wells

This regulation change increases the daily minimum gas allowable in Kansas from 150 to 250 Mcfpd and exempts such minimum gas wells from the burden of annual gas well testing (including the required 72 hour shut-in period). Requires that the operator must apply for the exemption and annually report to the Kansas Corporation Commission the well head shut-in pressure for such minimum wells that have been exempted. This includes all coal seam gas wells and conventional gas wells that produce less than 250 Mcfpd.

Citation: K.A.R. 82-3-304

Effective date: Jan. 25, 2002

Goal: This incentive is designed to minimize the loss of gas production sales and associated expenses of the gas well test (pulling unit time, labor, etc.) for minimum wells.

Active supporters: Kansas Corporation Commission, Kansas Independent Oil and Gas Association and the Kansas Petroleum Council

Gas Allowables and Drilling Unit

This regulation change increases the daily allowable from 25% of the well's calculated absolute open-flow (AOF) to 50% of AOF. This amended rule also raises the minimum gas allowable from 150 Mcfpd to 250 Mcfpd.

Citation: K.A.R. 82-3-312

Effective date: Jan. 25, 2002

Goal: To allow more gas to be produced from Kansas wells.

Active supporters: Kansas Corporation Commission, Kansas Independent Oil and Gas Association, and the Kansas Petroleum Council

Temporarily Abandoned Wells; Penalty; Plugging

This regulation change allows operators more than 90 days of non-production before having to file a temporary abandonment (TA) application. It also provides a framework for non-producing wells that may be fully equipped and capable of production relief from filing for TA approval up to 364 days of non-production (perhaps due to low oil or gas prices, etc.) and extends the 90 day time requirement for plugging or returning a well back into service.

Citation: K.A.R. 82-3-111

Effective date: Jan. 25, 2002

Goal: To allow operators more time to re-work, re-establish production for wells that may be non-producing for more than 90 days due to low product price or inability to obtain service equipment (pulling units, parts, etc.), without the formal filing of a TA application.

Active supporters: Kansas Corporation Commission, Kansas Independent Oil and Gas Association, Kansas Petroleum Council and the Eastern Kansas Oil and Gas Association

Unitization

This act empowers the Kansas Corporation Commission (KCC) to unitize a pool upon request of a

working interest owner under certain circumstances. First, the primary production from a pool has reached a low economic level and without introduction of artificial energy, abandonment of the well is imminent; or the unitized management sought is economically feasible and necessary to prevent waste. Second, the value of the estimated recovery is greater than the costs incident to conducting the recovery. Finally, the operation is fair and equitable. The act further establishes the rights of owners of oil and gas rights under unleased land as being a working interest to the extent of 7/8 interest and a royalty owner to the extent of 1/8 interest. The KCC can alter the extent of a royalty interest. Finally, the act states that it is the duty of the operator of the unit to file ad valorem taxes.

Citation: K.S.A. 55-1304, K.S.A. 55-1305, K.S.A. 55-1308 and K.S.A. 55-1312

Effective date: March 30, 2000

Goals: Promote secondary operation/management standards for unitization.

Active supporters: Kansas Independent Oil and Gas Association, Kansas Petroleum Council and the Kansas Corporation Commission

Property Taxation

This act relates to the property tax valuation of oil and gas properties. Factors to be considered when assessing property taxes include the age of the well, quality of product produced, nearness to market, the cost of operation, the probable life of the well, character, extent and permanency of market, the quantity of product produced, the number of wells being operated and other factors affecting the value of the lease. The act also establishes the method for calculating the property taxes.

Citation: K.S.A. 79-331

Effective date: April 13, 2000

Goal: To change the oil/gas valuation method for county property tax purposes.

Active supporters: Kansas Independent Oil and Gas Association, Kansas Petroleum Council and the Kansas Corporation Commission

Refundable Income Tax Credit for Property Taxes Paid

Working interest owners can receive an income tax credit equal to 75% of the 1998 personal property tax paid on the working interest of an oil lease, from which the average daily production per well is 15 barrels or less. The property tax must have been levied for property tax year 1998 and timely paid during the income tax year in which the credit is taken. By making the credit effective for the tax year beginning after Dec. 31, 1997, immediate relief is available. For taxable years commencing after Dec. 31, 1998, an income tax credit is allowed equal to 50% of the property tax paid for wells producing 15 barrels or less per day when the price per barrel is \$16 or less. The amount of the credit which exceeds the tax liability is refundable.

Citation: K.S.A. 79-32,208

Effective date: May 27, 1999; no sunset

Impact: \$8.2 million immediately available to operators with continued future relief for marginal wells when oil prices are \$16 per barrel or less.

Royalty Interests, Statute of Limitations on FERC-Ordered Refunds

The period of time during which first sellers of natural gas could commence a civil action against royalty interest owners to obtain refunds of reimbursements for ad valorem taxes on royalty interests during the years 1983 through 1988 was declared expired and the refund claims were deemed to be uncollectible. The legislature reaffirmed that the Kansas five year statute of limitations found in K.S.A. 60-511 applied to these claims created when the Federal Energy Regulatory Commission (FERC), more than 15 years after its initial determination, reversed its long-standing policy that the Kansas ad valorem tax,

which was based on production, was a severance tax and could be added to the maximum lawful price set by the NGPA at that time. FERC ordered first sellers to refund the amount of the ad valorem tax. This statute and that part of the FERC order relating to penalty and interest is under court challenge in both state and federal courts.

Citation: K.S.A. 55-1624

Effective date: April 30, 1998

Incremental Production

A severance tax exemption for a period of seven years is given to the incremental production resulting from a production enhancement project begun on or after July 1, 1998. Incremental severance and production is defined as production in excess of base production. Base production is the average monthly amount of production for the 12-month period immediately prior to the project beginning date, minus the monthly rate of production decline. The monthly rate of production decline would be determined with reference to the same 12-month period used to determine the base production. The monthly rate of production decline is the decline that would have occurred except for the enhancement project. The credit does not apply in any fiscal year if in the preceding calendar year the price exceeded, in the case of oil, \$20 per barrel; or, in the case of natural gas, \$2.50 per Mcf. Language was added to clarify the existing law to include wells that have an established incline in production volumes and for wells that have had casing failures (or for other reasons lack production volumes) immediately prior to the enhancement project.

Citation: K.S.A. 2005 Supp. 79-4217

Effective date: July 1, 2000

Goal: To promote old wells producing after enhancements, through tax relief.

Active supporters: Kansas Independent Oil and Gas Association, Kansas Petroleum Council and the Kansas Corporation Commission

Marginal/Stripper Wells

The existing severance tax exemptions for marginal/stripper wells was expanded to increase exemptions and to allow for further increases in exemption amounts if oil prices decrease. The two barrels of oil per day (BOPD) exemption on oil produced from a lease or production unit increased to an average daily production of five BOPD. The three BOPD exemption for wells with a completion depth of 2,000 feet or more increased to an average daily production of six BOPD. Further exemptions were provided for if the price of oil decreases. Oil priced at \$16 or less now has a seven BOPD exemption; should oil drop to \$13 per barrel, the exemption is 10 BOPD exemption. Tertiary recovery from a water flood process from wells of 2,000 feet or less now has a six BOPD exemption and wells in excess of 2,000 feet have a seven BOPD exemption. The exemption is 10 BOPD if the oil price reaches \$14 per barrel. Tertiary recovery oil priced at \$16 or less now has an eight BOPD exemption and \$14 oil would have a 10 BOPD exemption. The exemption for gas severed from a well having a gross value of not more than \$81 per day during a calendar month was increased to \$87.

Citation: K.S.A. 79-4217(b)(1) and (b)(2)

Effective date: May 1, 1998; no sunset

Goal: To prevent premature plugging of wells.

Secondary/Tertiary Recovery

Incremental production resulting from a tertiary recovery process is exempt from severance and production taxes.

Citation: K.S.A. 79-4217

New Wells/New Pools

Production from new pools is exempt from severance tax for 24 months from commencement of production.

Citation: K.S.A. 79-4217(b)(4)

Goal: To encourage exploration.

Impact: Industry spokesmen believe this is a very important exemption to Kansas' producers because it serves as a motivator for new exploration.

Natural Gas Severance Tax Reduction

Legislators enacted an annual stepped reduction in severance tax on natural gas from 7% to 4.33% over a three-year period. The final reduction took place in July 1996.

Citation: K.S.A. 79-4217

Effective date: July 1, 1994

Impact: The fact that natural gas has overtaken oil as Kansas' greatest-valued petroleum product is in part attributable to incentives such as this one.

Services

Electricity and other utilities used in the severance of oil and gas are exempt from state sales tax.

Citation: K.S.A. 79-3606

Effective date: July 1, 1994; no sunset

Natural gas used in injection projects, for fuel in recovery operations, or from a well having an average daily production with a value not more than \$87, is exempt from severance and production tax.

Citation: K.S.A. 4217(b)(1)

Effective date: July 1, 1994; no sunset

Kansas Geological Survey

The Kansas Geological Survey conducts research and provides information about the state's petroleum resources. The KGS conducts programs for the petroleum industry so the state will continue to enjoy the benefits of revenue generated by the industry and provides the petroleum industry with the benefits of research and information, as the state land grant schools provide support to the agricultural industry.

Citation: K.S.A. 76-322 through 326

Effective date: 1998

Goal: To encourage the development of natural resources of economic value.

Impact: Oil fields have been discovered based on KGS research. The KGS is widely recognized as being the source of much petroleum information and for its work on problems posed by the industry. The survey frequently appears before legislative committees in support of tax incentives and provides technical assistance to the industry.

Active supporters: State legislative support exists

Digital Petroleum Atlas, Kansas Geological Survey

This is a long-term program to develop a prototype digital petroleum atlas for the United States, starting with Kansas and extending into the adjoining mid-continent region. Extensive data sets about typical plays, details from pools in production and technologies that have provided the most effective exploration, development, production and additional recovery efforts are assembled and provided to operators in digital form. Hard copies are also available. The program focuses on helping operators determine why pools produce and behave the way they do so that analog techniques can be used where

appropriate, regardless of the age of the rock and geography of pool setting. Currently the program is 80% supported by federal funds and 20% supported by Kansas general funds.

Citation: Direct congressional appropriation, through the U.S. Department of Energy

Effective dates: August 1995; new appropriation in 1996

Goal: Lower exploration/production costs, increase success through technology/information transfer

Petroleum Research Section, Kansas Geological Survey

The PRC conducts research and provides instructional services for the Kansas petroleum industry. It uses a wide variety of technologies and has a broad range of scientific interests. Most members of the section have industry experience. The section also operates the public Kansas Well Core Library.

Goal: To stem the decline in oil production by providing research and petroleum data to industry.

Impact: Reviews of the section's research and workshops have been very strong. The discovery of the Bluebell Field in Kansas has been attributed to work done by this group. The Petroleum Research Section is a national leader in making petroleum data available electronically, especially through the Internet.

University of Kansas Energy Research Center

The Kansas Geological Survey and the University of Kansas fund an integrated energy research program focused on petroleum. The Research Center coordinates information relating to ongoing petroleum research, and makes that information available to industry.

Goal: To stimulate energy research and assist in gaining funding and help maintain the Kansas energy industry.

Impact: The program has contracted more than \$6.6 million in support of energy research. Many conferences and short courses have been held. The program integrates staff in 18 university departments that conduct energy research.

Active supporters: Kansas Geological Survey and academic units of the University of Kansas, including the geology department and the Tertiary Oil Recovery Project

Technical Information Services for the Petroleum Industry

Through Technical Information Services, the Kansas Geological Survey provides public access to petroleum data, including scout tickets and well log data. The Well Sample Library in Wichita operates the sample cuts, archives well samples and makes these materials available to operators.

Effective date: 1987 (with earlier precursors)

Goal: To encourage oil and gas production by making useful data available to producers; counteract the loss of infrastructure in the independent industry.

Active supporters: Kansas Geological Survey

KENTUCKY

Credit for Production From Recovered Inactive Oil Wells and Gas Wells

These two incentives give producers a credit on the 4.5% severance tax imposed on production from oil and gas wells that are brought back into production after having been inactive for two years, or plugged and abandoned.

Citation: KRS 137.132 and KRS 143A.033

Effective date: July 15, 1998; no sunset

Goal: To recover inactive or abandoned wells.

Active supporters: Kentucky Oil and Gas Association, Kentucky Division of Oil and Gas

Investigation of Abandoned Wells

This statute allows producers with a proper testing permit to test inactive wells for 60 days prior to posting bond for the well.

Citation: KRS 353.730

Effective date: July 15, 1998; no sunset

Goal: To recover inactive or abandoned wells.

Active supporters: Kentucky Oil and Gas Association, Kentucky Division of Oil and Gas

LOUISIANA

Severance Tax Relief; Act 31

Provides exemptions from state and local sales and use taxes for repairs and/or materials used on drilling rigs and equipment used exclusively for exploration and development of minerals outside the territorial limits of the state in the Outer Continental Shelf.

Citation: LSA - R.S. 47:305 (1)

Effective date: July 1, 2002

Goal: To provide tax relief.

Active supporters: Reps. Murray and Thompson; and Sen. Romero

Severance Tax Relief; Act 2 of 1994

This act, re-enacting LA. R.S. 47:633, reduced severance taxes on the following categories of wells in order to stimulate exploration and development:

1. **Stripper Oil Wells and Incapable Oil Wells**
Oil wells producing less than 10 barrels of oil per day are exempt from severance taxes during any month in which oil prices average less than \$20 per barrel. When oil prices are greater than \$20 per barrel, severance tax is reduced by 75% to 3.125%. Wells producing more than 10 and less than 25 barrels of oil per day with at least a 50% saltwater cut are taxed at 6.25%, a 50% reduction.

Citation: LA. R.S. 47:633, S.B. 31 (1994), LA. R.S. Ann. of 1950, (renewed by Act 16 of 1996)

Effective dates: July 1994

2. **Horizontal/New Discovery/Deep Gas or Condensate Wells**
Severance taxes for oil or gas from horizontally drilled wells or recompletions, certified new discovery oil and natural gas wells, and gas or condensate produced from wells drilled to at least 15,000 feet are suspended from the date of first production for a period of 24 months (extended in 1996 Act 16 and in 1998 Act 7), or until payout of the well cost, whichever comes first. Payout of the well

cost shall be determined by the Department of Natural Resources. To be eligible, new discovery wells must be completed in a new reservoir before Sep. 30, 2000.

Citations: Act 2 (S.B. No. 31); S.B. 32, amending LA. R.S. Ann. 47:633(7)(c)(iv)(a) and 648.2(1)(c), LA. R.S. Ann. of 1950; 1996 Act 16

Effective date: July 7, 1994; no sunset

Goal: To encourage horizontal, new and deep well drilling. This is consistent with the public policy of Louisiana to promote economic growth and revitalize and stimulate the petroleum industry.

Produced Water Injection

To help accomplish the objective of reducing the discharge of produced water and to help ease the tremendous financial burden placed on the oil and gas industry, it is the purpose of this section to provide an economic incentive to producers of oil and gas by allowing them to realize a severance tax savings (20% on incrementally produced oil and gas) if they inject produced water into an oil or gas reservoir for the purpose of increasing the recovery of hydrocarbons.

Citation: LA. R.S. 47:633.5

Effective Date: July 17, 1991

Orphan Well Plugging

Act 404 of the 1993 Regular Session established the Oilfield Site Restoration (OSR) Law which includes an orphan well plugging and site restoration fund. Fund oversight is provided by an OSR Commission. Revenue for the fund is generated from a fee on oil and gas production in the State of Louisiana which is paid quarterly by Louisiana oil and gas operators. The imposed fee on production is in the amount of \$.015 per barrel of oil and condensate and \$.003 per mcf of gas. Additionally, in accordance with the provisions of the OSR Law, when a transfer of ownership interest of an oilfield site occurs, either party of the transfer can elect to file an application to establish a site-specific trust account to cover future restoration costs. Doing this relieves the fee-generated portion of the fund from the financial burden of paying for restoration at the site covered by the SSTA in the event the site is orphaned. SSTA funds are not for general program use and are earmarked specifically to be used to restore the site to which they are dedicated. Once established, site-specific trust accounts remain with the site through subsequent property transfers.

Citation: Louisiana Oilfield Site Restoration Law - LA. R.S. 30:80 et seq.

Effective Date: May, 1993

Tertiary Recovery

No severance tax shall be due on production from a qualified tertiary recovery project approved by the Secretary of the Department of Natural Resources until the project has reached payout. Payout is calculated from the total of production from investment costs; expenses particular to the tertiary project, not to include charges attributable to primary and secondary operations on that reservoir; and interest at commercial rates.

Citation: LA. R.S. Ann. 47:633.4

Effective date: July 12, 1984; no sunset

Goal: To provide an economic incentive to producers to invest in tertiary recovery projects to enhance Louisiana's crude oil production, to the ultimate benefit of the state and the people.

Impact: Enhanced oil recovery projects have taken place, but it is unknown how many would have taken place in the absence of an incentive. One large project is currently active. Industry investment in the project is approximately \$30 million. While the effectiveness of the program has not been studied,

analysis of statistics from the Louisiana Department of Natural Resources and Department of Revenue and Taxation would be informative.

Active supporters: Oil and gas industry, legislative leaders

Marginal Gas Wells

Gas wells producing less than 250 Mcf per day are taxed at a reduced rate of \$0.013/Mcf.

Citation: LA. R.S. 47:633

MARYLAND

Coal Bed Methane

Environmental Article 14-112 allows for the placement of coal bed methane wells at 500 feet from unleased property. The standard was previously 1,000 feet, and remains that distance for all other wells. This took effect on July 1, 2006. The bill was supported and introduced by industry. The Department supported it but did not initiate any action.

There are no taxes on gas produced in Maryland due to the small volume, so no tax incentives are relevant.

MICHIGAN

Marginal/Stripper Wells

Severance taxes are reduced from 6.6% to 4% for production from stripper oil wells. The severance tax rate for all gas production is 4%. Stripper oil wells are defined by the state as wells with an average maximum daily production less than or equal to 10 BOPD. Production from marginal oil properties receives the same reduction when average per well production is:

- 20 BOPD or less for properties with average completion depths greater or equal to 2,000 feet but less than 4,000 feet;
- 25 BOPD or less for properties with average completion depths greater or equal to 4,000 feet but less than 6,000 feet;
- 30 BOPD or less for properties with average completion depths greater or equal to 6,000 feet, but less than 8,000 feet;
- 35 BOPD or less for properties with average completion depths of at least 8,000 feet.

Citation: 1929 Mich. Pub. Acts 48

Effective date: March 19, 1996; no sunset

Goal: To increase well life and volume of production.

Impact: This program encourages marginal and stripper wells to produce and not be plugged and abandoned.

Active supporters: Petroleum industry and Michigan state government

Note: The Michigan Court of Appeals, on July 23, 1996, held in an unpublished case that severance

tax is not due on gas used on-site to purify gas, as purification costs are part of the costs of production. This decision is favorable to oil and gas producers.

MISSISSIPPI

Enhanced Oil Recovery

Reduces the assessed tax rate to 3% of the value of the oil produced by an enhanced oil recovery method in which carbon dioxide is used when transported by a pipeline to the oil well, has been expanded to include any other enhanced oil recovery method approved and permitted by the State Oil and Gas Board on or after April 1, 1994.

Citation: Miss. Code Ann. § 27-25-503 (1) (2001)

Effective date: April 1, 1994; no sunset

Goal: To encourage the use of enhanced recovery methods of production.

Impact: Believed to have increased the use of enhanced oil recovery techniques.

Active supporters: Mississippi Independent Producers and Royalty Owners Association and Mid-Continent Oil and Gas Association

Carbon Dioxide Reductions and Exemptions

As noted above under Enhanced Oil Recovery, there is a reduction in the rate of the privilege tax to 3% for oil leases using enhanced production methods in which carbon dioxide is used. This appears in Miss. Code Ann. § 27-25-503. Mississippi law also provides that gas, including carbon dioxide, used for purposes of injection shall be exempt from the state's 6% privilege tax. This exemption only applies to carbon dioxide to be used for enhanced oil recovery projects within the state of Mississippi.

Citation: Miss. Code Ann. § 27-25-703 (2) (2001)

MISSOURI

Plugging

The Missouri Code of State Regulations requires that oil and gas operators must permanently plug abandoned wells in a manner that complies with the code. Any operator who fails to fulfill this obligation may be issued a notice of violation from the Missouri Department of Natural Resources. There are no economic incentives available in Missouri for plugging oil or gas wells.

MONTANA

Horizontally Recompleted Wells

Horizontally recompleted oil wells pay a reduced production tax rate on the incremental production for the first 18 months of production after recompletion. This incentive is suspended when the price of West Texas Intermediate crude oil exceeds \$30 per barrel for a calendar quarter and reactivates when the price of oil drops below \$30 per barrel. Wells that have not produced for five years or more are

treated, for tax purposes, as new wells (see also: Horizontal Wells section).

Citation: Mont. Code Ann. tit. 15, Chapter 9 (1993)

Effective dates: January 1, 1994; no sunset

Goal: To encourage the use of advanced technologies in oil production.

Impact: It is reported that major producers have drilled more horizontal wells than anticipated, which may be at least partially in response to this incentive program. The recent 4% per year decline in production has nearly leveled off.

Active supporters: Montana Petroleum Association, Shell Western Exploration and Production, Burlington Resources Oil and Gas (formerly Meridian Oil), oil and gas county commissioners and land and mineral owners associations

Horizontal Wells

Production taxes for oil or gas wells that are completed horizontally or for horizontally recompleted oil wells that have not been producing for five years or more are exempt from production taxes, except for the 5% resource indemnity tax for the first 18 months of production.

Citation: Mont. Code Ann. tit. 15, Chapter 9 (1993); amended Chapter 554 (1999)

Effective dates: Dec. 31, 1993; Jan. 1, 1999

Impact: With the increase in oil prices in the years of 2000-2001, operators in existing fields have used the idle well, horizontal recompletion incentive and have increased production. The horizontal incentive has been popular since its inception in 1993.

New Wells

Oil or gas production from new wells, or wells that have not produced for five years, are exempt from production taxes, except for the 5% resource indemnity tax, for the first 12 months of production.

Citation: Mont. Code Ann. tit. 15, Chapter 451 (1995)

Effective date: Jan. 1, 1996

Goal: To stimulate exploration and new production.

Impact: The incentive is a factor in the more favorable tax climate for new production, and keeps Montana competitive with neighboring states for drilling dollars.

Active supporters: MPA, Northern Montana Oil and Gas Association, oil and gas county commissioners, land and mineral owners associations

Secondary/Tertiary Recovery

Production taxes are reduced for incremental production from secondary and tertiary recovery projects. Incremental secondary production is taxed at 8.5%. Incremental tertiary production is taxed at 5.8%. This incentive is suspended when the price of West Texas Intermediate crude oil exceeds \$30 per barrel for a calendar quarter and reactivates when the price of oil drops below \$30 per barrel.

Citation: Mont. Code Ann. tit. 15, Chapter 9 (1993); amended Chapter 451 (1995)

Effective date: Jan. 1, 1994

Goal: To extend economic life of depleted wells and fields through advanced technology application.

Impact: Oil production for 1995 is virtually flat, with 1994 production stemming an annual decline of 4% per year in previous years. This incentive coupled with the state's horizontal wells incentive is credited with stemming this decline.

Active supporters: MPA, Shell Western Exploration and Production, Burlington Resources Oil and Gas, oil and gas county commissioners, land and mineral owners associations

Marginal/Mini Stripper Wells (three barrels per day or less)

Oil from a well which produces three barrels per day or less is exempt from production taxes, except the 5% resource indemnity tax. A suspension clause eliminates this tax exemption when West Texas Intermediate crude oil prices reach \$38 per barrel for a calendar quarter and reactivates when the price drops below \$38 per barrel. State defines stripper oil wells as those producing 15 barrels per day or less.

Citation: Mont. Code Ann. tit. 15, Chapter 488 (1999); amended Chapter 421 (2001)

Effective date: July 1, 1999

Goals: To keep marginal wells in production, preserve jobs and prevent premature abandonment.

Impact: Incentive trigger price raised to \$38 West Texas Intermediate in 2001 session. Operators testified that wells were kept in production and employees were hired to service the wells.

Active supporters: NMOGA, MPA, county commissioners, land and mineral owner associations

Marginal/Stripper Wells (10 -15 barrels per day)

The production tax rate on the first 10 barrels produced from a stripper oil well is 5.5%. The production tax rate is 9% on the next 10 - 15 barrels of oil produced from a stripper well. Lower tax rates are provided for stripper well production when the price of West Texas Intermediate crude oil remains below \$30 per barrel in a calendar quarter. Montana defines a stripper oil well as a well that produces less than 15 barrels per day.

Citation: Mont. Code Ann. tit. 15, Chapter 530 (1999)

Goal: To increase Montana's oil production, keep marginal wells in production and maintain the jobs associated with these wells.

Services

Crude oil or gas used by operators in connection with operations is tax exempt.

Citation: Mont. Code Ann. § 15-36-305

Effective date: Title chapter currently in effect

Goal: To make the tax code more equitable by not taxing production which is actually a cost of doing business and not to be sold for a profit.

NEBRASKA

Marginal/Stripper Wells

A severance tax reduction from 3% to 2% is available for oil wells that produce less than 10 BOPD.

Citation: Neb. Rev. Stat. tit. 57, §§ 701 through 719

NEVADA

Reduced Administrative Fee for New Production

The amount of the administrative fee that a producer or purchaser of oil or natural gas must pay on new production pursuant to subsection 2 of Nevada Revised Statute 522.150 is one-half cent (five mills) per barrel of oil or per 50,000 cubic feet of natural gas, as appropriate. New production is defined as production from new wells or existing wells completed in new intervals as determined by the Commission on Mineral Resources. Any qualifying well will receive a reduced administrative fee for one full year. Upon completion of a qualifying well, the producer will submit a form five, "Well Completion Report." The production date as reported on the form five will be the effective date for the reduced fee.

Citation: NAC 522.343; NRS 522.040,50

Effective date: Jan. 27, 2000

NEW MEXICO

Credit for Produced Water

This new law provides for a tax credit of \$1,000 per acre-foot of cleaned produced water that is pumped into the Pecos River. The pumping of the water must be in compliance with state and federal clean water regulations. This law allows for a annual tax credit up to an amount of \$400,000.

Citation: NMSA 7-2-18.9

Effective date: Expired Jan. 1, 2006; repeal passed in 2002

Goal: To help New Mexico meet its regulatory obligation to deliver water to Texas.

Marginal/Stripper Wells

Reduces both severance and emergency school taxes for stripper well properties having average daily production of less than 10 barrels or 60 Mcf per eligible well. Severance taxes are reduced from 3.75% to 1.875% or 2 13/16% and emergency school taxes are reduced from 4% to 2% or 3% for gas and from 3.15% to 1.58% or 2.36% for oil during periods of low prices (less than \$1.15 and between \$1.15 and \$1.35 per Mcf for gas and less than \$15 and between \$15 and \$18 per barrel for oil).

Citation: Oil Conservation Division Rule 33; §§ 7-29B-1 through 7-29B-6, NMSA 1978, amended

Effective date: June 18, 1999; no sunset

Goal: To encourage production from marginal wells, avoid premature abandonment and plugging.

Well Workover Project

Reduction in severance taxes from 3.75% to 2.45% for oil and gas produced from wells having qualified workover operations performed. Does not apply when oil price is \$24 or more per barrel.

Citation: OCD Rule 32; §§ 7-29B-1 through 7-29B-6, NMSA 1978, as amended

Effective dates: June 16, 1995; amendment effective June 1, 1999. Prior to that time, 1.875% rate applies to only the incremental production; no sunset

Goal: To encourage operators to perform workover operations to increase production and avoid premature abandonment and plugging.

Production Restoration Project

Exemption from severance tax (3.75%) for wells that had fewer than 31 days of production in any period of 24 consecutive months after Jan. 1, 1993, which are brought back into production. Does not apply when the oil price is \$24 or more per barrel.

Citation: OCD Rule 31; §§ 7-29B-1 through 7-29B-6, NMSA, 1978 as amended

Effective date: June 16, 1995; no sunset

Goal: To encourage operators to return wells to production and avoid premature abandonment and plugging.

State Royalty Reductions

A lower royalty rate (5%) applies to oil wells operated pursuant to a state oil and gas lease if the wells averaged: (i) less than 3 BOPD for the preceding 12-month period but not more than 5 BOPD for any month during that 12 month period if producing from shallower than 5,000 feet; and (ii) less than 6 BOPD for the preceding 12-month period but not more than 10 BOPD for any month during that 12-month period for production from 5,000 feet or deeper. Certain conditions apply and an application and fee are required.

Citation: § 19-10-5.1, NMSA 1978, as amended

Effective date: May 18, 1994; no sunset

Goal: To encourage production from marginal wells and avoid premature plugging and abandonment.

Enhanced Oil Recovery Projects

Severance tax reduced from 3.75% to 1.875% for oil produced from the date of positive production response. OCD approval is required. Does not apply when the oil price is \$28 or more per barrel.

Citation: OCD Rule 30; Enhanced Oil Recovery Act, §§ 7-29A-1 through 7-29A-5, NMSA 1978

Effective dates: March 6, 1992, for carbon dioxide injection projects; Jan. 1, 1994, for processes other than carbon dioxide; no sunset

Goal: To encourage the use of enhanced recovery techniques, including waterflooding, pressure maintenance and tertiary recovery projects or expansions.

NEW YORK

New York State Energy Research and Development Authority

The New York State Energy Research and Development Authority (NYSERDA) was created by the state's Legislature in 1975 as a public benefit corporation. One goal of NYSERDA's research and development program is to expand the use of New York State's indigenous and renewable energy resources. NYSERDA's natural gas program has evolved into a multifaceted research and development program structured around the following goals: to help develop new natural gas reserves through innovative exploration methods and reservoir studies; to enhance existing reservoir production by developing or demonstrating new technology and products; to increase natural gas storage from depleted natural gas fields and bedded salt; to improve industry environmental performance; and to conduct extensive industry outreach to educate firms on opportunities for economic production in New York state.

Additionally, NYSERDA funds carbon sequestration research. Over the last ten years, NYSERDA has provided more than \$6 million for over 80 natural gas, petroleum and carbon sequestration projects.

Information on NYSERDA's programs can be found at www.nyserda.org.

Natural Gas and Petroleum Exploration, Production and Carbon Sequestration Program

The program helps create economic activity in New York State through the identification, development and use of indigenous natural gas and petroleum as well as the identification of carbon sequestration reservoirs. Selected projects will target resource exploration and development projects that can bring new production online within a reasonable time frame (less than three years). Eligible projects will include resource characterization studies, prospect development projects and end-use economic development projects will use indigenous resources to fuel a New York State end-use partner. Eligible carbon sequestration reservoir characterization projects will identify prospective rock units that may offer significant reservoir volume.

NORTH DAKOTA

North Dakota has a gross production tax of 5% and an extraction tax of 6.5% on oil.

Extraction Tax Trigger

Excise tax incentive elimination on oil production will occur if West Texas Intermediate crude oil averages \$42.89 each month for five consecutive months. The trigger price will be adjusted for inflation on an annual basis by the North Dakota Tax Department. For an operator, this can immediately reduce taxes by 2.5 - 6.5%. The North Dakota Industrial Commission - Oil and Gas Division (NDIC) and the North Dakota Petroleum Council (NDPC) are monitoring the effectiveness of this incentive.

Citation: North Dakota Century Code (NDCC) 57-51.1-01

Effective date: August 1, 2001; no sunset

Goal: Clarify trigger mechanism and adjust trigger price for inflation.

Active supporters: NDPC member companies

New Wells

Production from new wells drilled and completed after April 27, 1987, is exempt from extraction taxes for the first 15 months of production and taxed at a rate of 4% thereafter (reduced from 6.5%).

Citation: North Dakota Administrative Code (NDAC) 81-09-03 § 06

Effective date: July 1, 1987; no sunset

Horizontal Wells

Production from new horizontal wells drilled and completed after April 27, 1987, but before April 1, 1995, is exempt from extraction taxes for the first 15 months following well completion, and is then taxed at a rate of 4% thereafter. Oil produced from a horizontal well drilled and completed after March 31, 1995, is exempt for the first 24 months. See trigger provisions above.

Citation: NDAC 81-09-03 § 06

Effective date: April 1, 1995; no sunset

Impact: Excellent, according to the NDPC, which finds that horizontal drilling has increased. The NDPC attributes significant increases of drilling activity to this incentive, plus new technology, new finds and good oil prices. The NDIC's statistics show an increase in permits and a decline in the rate of well plugging. As an unexpected benefit, while pursuing new horizontal plays, new plays and new

fields have been discovered.

Horizontal Re-entry Well Exemption

Oil produced from a horizontal re-entry well during the first nine consecutive months starting with the date the well was re-completed as a horizontal well is exempt from the oil extraction tax. The designation of a horizontal re-entry well is given to a well initially drilled and completed as a vertical well which is re-entered and re-completed as a horizontal well after March 31, 1995. This designation may also apply to the re-entry and recompletion of a vertical well that is classified by the NDIC as a dry hole.

Citation: NDAC 81-09-03-10

Workover Project Determination

Applicants have the burden of establishing entitlement to the exemption provided in NDCC § 57-51.1-03 and upon completion of the workover project shall submit all information necessary for a determination by the director. Production resulting from qualifying workover projects is exempt from extraction taxes for 12 months, beginning the third month after completion of the workover project, and is taxed at 4% thereafter. Wells that have produced less than 50 BOPD during the last six months of continuous production before workover qualify for this exemption. The operator must notify the NDIC before beginning the project. The project must cost at least \$65,000, or production must increase 50% or more in the first two months after project completion. See trigger provisions above.

Citation: NDAC 43-02-09-04; NDAC 81-09-03 § 08

Effective date: Aug. 1, 1989; no sunset

Active supporters: NDIC

Idle Wells

Production from oil wells that have been inactive for at least two years and are returned to production is exempt from extraction taxes for 10 years, beginning the first day of the month in which NDIC certification is received by the Tax Commissioner.

Citation: NDAC 81-09-03 § 11

Effective date: April 1, 1995; no sunset

Impact: According to NDPC, this and most of the other incentives have been successes.

Active supporters: This and the following incentives were promoted by the NDPC dating back to 1987. In most efforts, it received vigorous support from oil producing counties, rural electric cooperatives and economic development organizations.

Temporary Abandonment of Wells, Suspension of Drilling

This rule defines what constitutes abandonment of a well in the state of North Dakota. The rule also dictates how soon after abandonment a well is to be plugged and the drill site reclaimed. By giving the well temporarily abandoned status, the NDIC director may waive this requirement for one year. The director may extend a well's temporarily abandoned status annually. The director also may approve suspension of the drilling of a well. If suspension is approved, a plug must be placed at the top of the casing. Unless authorized by the director, a well must be plugged and its site reclaimed if drilling has been suspended for 30 days.

Citation: NDAC 43-02-03-55

Effective date: Aug. 1, 1999

Goal: To prevent the permanent plugging of wells due to low oil prices.
Active supporters: NDIC

Stripper Well Property Determination (No Trigger)

This section outlines the requirements for an operator desiring to classify a property as a stripper well property for the purposes of exempting production from extraction taxes. Oil produced by stripper wells is exempt from extraction taxes. Stripper wells are defined as wells with an average daily production during a twelve month consecutive qualifying period of up to 10 BOPD at a depth of less than 6,000 feet; up to 15 BOPD at a depth of 6,000 to 10,000 feet; and up to 30 BOPD at depths greater than 10,000 feet. Stripper wells must be certified by the NDIC. This section was amended in May 2004 to offer operators the opportunity to reclassify already determined single well stripper properties as another type of property.

Citation: NDAC 81-09-03 § 07; NDAC 43-02-08

Effective date: Aug. 1, 1987; no sunset

Goal: Provide incentive for marginal wells.

Active supporters: NDIC

Effective date: April 1, 1995; no sunset

Goal: To increase oil production from a reservoir.

Active supporters: Oil and gas industry

Bakken Horizontal Well

The first seventy-five thousand barrels of oil produced during the first eighteen months after completion, from a horizontal well drilled and completed in the Bakken formation, is subject to a reduced tax rate of two percent of the gross value at the well of the oil extracted.

Citation: NDCC 57-51.1-03

Effective date: July 1, 2007, through June 30, 2008

Goal: Provide incentive for Bakken Pool exploration.

Active supporters: NDIC, NDPC

Statutory Unit Ratification

The statute lowers the percentage of working interests and mineral owners approval required to form and dissolve an oil production unit from 70% to 60%. The NDIC and the NDPC are monitoring the effectiveness of this incentive.

Citation: NDCC 38-08-09.5

Effective date: Aug. 1, 2001; no sunset

Goal: Lowering the unitization percentage has been a controversial issue for more than twenty years; the lower percentage will help production companies implement secondary recovery methods.

Active supporters: NDPC member companies

Secondary/Tertiary Recovery (No Trigger on Incremental Oil)

Incremental oil from secondary recovery projects is exempt from extraction taxes for five years, and incremental oil from tertiary projects is exempt for 10 years from the date incremental production commences. All oil from a qualifying secondary or tertiary recovery project is taxed at a reduced rate of 4% once the five- or ten-year exemption has expired.

Non-incremental oil from a qualifying secondary recovery project, when its average production level has increased to at least 25% over normal operations for six months, is taxed at a reduced rate of 4%.

Non-incremental oil from a qualifying tertiary recovery project that produces at least 15% above normal operations for one month and continues to operate as a qualified project is taxed at a reduced rate of four percent.

Citation: NDAC 81-09-03, 05, 05.1, 05.2, NDCC 57-51

Effective date: Aug. 1, 1987; no sunset

Goals: To encourage use of secondary and tertiary recovery technologies and to encourage new investment in unitized fields.

Impact: Secondary and tertiary recovery projects have increased significantly.

Tribal Lands Oil Tax Exemption (No Trigger)

Initial production of oil from a well is exempt from extraction tax (6.5%) for 60 months if:

- . the well is located on a reservation, or
- . the well is located on trust land held for a tribe, or
- . the land is held by a tribe at the time this Act was passed.

Citation: NDCC 51-51.1-03(8)

Effective date: July 31, 1997; no sunset

Goal: To encourage petroleum development upon tribal lands.

Active supporters: Private individuals and independent producers

Shallow Gas Wells (No Trigger)

Shallow gas from new or re-completed wells drilled and completed after June 30, 2003, is exempt from gross production taxes for the first 24 months of gas sales.

Citation: 57-51-02.4

Effective dates: July 1, 2003, no sunset

Goal: To foster and encourage exploration, development and production of natural gas resources.

Active supporters: Oil and Gas District Legislators

Services (No Trigger)

Natural gas used on-site in the production of oil or gas is exempt from production taxes.

Citation: NDAC 81-09-02 § 16

Effective date: Adopted Aug. 1, 1986, and amended July 1, 1989; no sunset

OHIO

Emergency and Hazardous Chemical Inventory Form

In lieu of Ohio oil/gas well owners filing hazardous chemical inventory forms under the Community Right to Know Act, the well owners will be deemed to have complied by virtue of having filed well completion and annual production statements with the Division of Mineral Resources Management (DMRM). The well completion and annual statement of production forms were amended to include the number of storage tanks associated with the well and the storage capacity of those tanks. This information along with detailed well information can be found on the Division's Web site (<http://www.ohiodnr.com/mineral/index.html>). Additionally, a link is provided in DMRM's Web site to the "Oil and Gas Well Emergency Response System" that was developed with U.S. Department of Energy (DOE)

funding through the Argonne National Lab. This site provides emergency responders with well owner contact phone numbers, emergency officials phone numbers and site specific information on a well by well basis.

Citation: OAC 3750

Effective date: September 2001; no sunset

Goal: Provide for broader based availability of information in the event of emergencies.

Impact: Lessen reporting requirements for Ohio oil/gas well owners and to provide for web based availability of well specific information to emergency providers.

Active Supporters: Ohio oil/gas well owners, Division of Mineral Resources and the Ohio Oil and Gas Association

Plugging

A landowner grant program has been established for the plugging of orphan wells. Between \$300,000 and \$500,000 per year will be set aside to fund this program. Eligible landowners can plug the orphan wells on their land sooner and have more control in the plugging process than in the state's traditional bid process. The landowners must receive bids from contractors for a plugging plan that complies with state regulations and submit an application to the Division of Mineral Resources Management. If approved, the landowner will be reimbursed for the cost of plugging.

Citation: Ohio Revised Code § 1509.071

Effective date: Oct. 25, 1995

Goal: To encourage landowner-initiated plugging of orphan wells at a lower cost to Ohio.

Impact: This program provides the division with a second effective mechanism to plug orphan wells in Ohio.

Active Supporters: Ohio Oil and Gas Association

Amendment to Plugging

This amendment permits the division to transfer to landowners or their agents for production, a well eligible for plugging under this program if Ohio's well ownership requirements are met. Wells previously abandoned will become property of the state. Landowners or registered well owners can take over the well for production.

Ohio Oil and Gas Energy Education Program

With the passage of Substitute Senate Bill 46 in December 1997, and the approval of independent producers and royalty owners in a required referendum held in March 1998, the Ohio Oil and Gas Energy Education Program (OOGEEP) became effective on April 1, 1998.

OOGEEP is a nonprofit organization and is funded entirely by independent producers and royalty owners through an assessment on the production of all crude oil and natural gas in Ohio. The assessment on crude oil is equal to one cent (\$0.01) per gross barrel and one-tenth of one cent (\$0.001) per gross thousand cubic feet of natural gas. All first purchasers of crude oil and natural gas are required to collect the assessment and submit quarterly payments directly to OOGEEP.

The OOGEEP Operating Board consists of six independent producers and one member representing a farmer's organization. As outlined in the Ohio Revised Code, they are appointed by the Ohio Department of Natural Resources, Division of Minerals Resources Management (formerly known as the Division of Oil and Gas), Technical Advisory Council based upon recommendations from a qualified producers organization and an organization representing farmers, such as the Ohio Oil and Gas Association and the Ohio Farm Bureau.

OOGEEP has completed a comprehensive oil and gas training guide, Responding To Oilfield Emergencies Field Guide One; a training CD; and its first permanent training facility in an effort to assist and support local emergency responders. These tools enable them to understand and implement effective emergency response practices at typical oilfield and production sites. Ohio was the first state to offer such a safety training program to its emergency responders.

The training guide, training CD and workshops cover the following topics:

- overview of the oil and gas industry;
- communicating the emergency;
- evaluating the emergency;
- responding to drilling site emergency;
- description and pictures of typical equipment found at an oilfield site; and
- related informational resources.

In addition to the Oilfield Emergency Response program, OOGEEP facilitates other educational programs that encourage oil and gas education curricula in classrooms; promote public awareness about the industry, and educate and promote safety information.

Citation: Ohio Revised Code §§ 1510.01 - 1510.13

Effective Date: April 1, 1998

Goals: OOGEEP's goals include facilitating educational programs, encouraging oil and gas education curriculum in classrooms, promoting public awareness about the industry, educating and promoting safety information on related facilities and equipment and demonstrating to the general public the importance and economic significance of the industry.

Active supporters: Active supporters of the Oilfield Emergency Response program include: OOGEEP, Ohio Oil & Gas Association, Ohio Department of Natural Resources Division of Mineral Resources Management and various emergency response agencies

Division of Mineral Resources Management

Under house bills 278 and 279, Ohio Revised Code Sections 1509.02, 1509.03, 1509.06, 1509.23 and 1509.31 were amended and 1509.39 was repealed. The amendments and repeal provided for the Division of Mineral Resources Management to be the sole and exclusive authority to regulate the permitting, location and spacing of oil and gas wells in Ohio. The house bills created the Oil and Gas Advisory Council who advised the chief on rules drafted pursuant to the enactment of the bills.

Public hearings were held on the draft rules in June and July of 2005 with the effective date of the rules in August 2005. The rules provide more authority for the chief in the areas of safety during the drilling and production of oil and gas wells, protection of groundwater resources and environmental protection for wells drilled in "urbanized areas" (all municipal corporations and any township with an unincorporated population exceeding 5,000).

Citation: Ohio Revised Code Sections 1509.02, 1509.03, 1509.06, 1509.23 and 1509.31 (amended) and 1509.39 (repealed)

Effective Date: August 2005

Goal: The changes provide for one public entity to regulate the permitting and operation of oil and gas wells in Ohio, versus an array of local ordinances/regulations. One regulatory authority with the law and rules based on sound practices will enable the oil and gas industry to better and more efficiently identify drilling prospects thereby creating the opportunity for additional wells to be drilled in Ohio.

OKLAHOMA

Reduction in the State's Gross Production Tax on Oil

The gross production tax rate levied on oil was changed from a rate of 7% to a variable rate of either 7%, 4% or 1%. Effective with the January 1999 production month, the gross production tax rate on oil is as follows:

- If the average price of Oklahoma oil as determined by the Tax Commission equals or exceeds seventeen dollars (\$17.00) per barrel, the tax shall be levied at seven percent (7%).
- If the average price of Oklahoma oil as determined by the Tax Commission is less than seventeen dollars (\$17.00) but equal to or exceeds fourteen dollars (\$14.00) per barrel, the tax shall be levied at four percent (4%).
- If the average price of Oklahoma oil as determined by the Tax Commission is less than fourteen dollars (\$14.00) per barrel, the tax shall be levied at one percent (1%).

Citation: Okla. Stat. tit. 68, § 1001 (B) (2002)

Effective dates: Jan. 1, 1999, through June 30, 2007

Note: Effective July 1, 2003, the average price as computed by the Oklahoma Tax Commission for both oil and natural gas shall be used to determine the applicable tax rate for the third month following production.

Citation: Okla. Stat. tit. 68, § 1001 (B)(3) (2002)

Note: Effective July 1, 2003, the average price as computed by the Oklahoma Tax Commission for both oil and natural gas shall be used to determine the applicable tax rate for the third month following production.

Citation: Okla. Stat. tit. 68, § 1001 (B)(3) (2002)

Sales Tax Exemption on Sale of Electricity and Associated Delivery and Transmission Services Sold for Operation of Reservoir Dewatering Project and/or Unit

The increased use of dewatering methods in certain carbonate and shale reservoirs in Oklahoma, which typically have a high water cut during the initial phase of hydrocarbon production, stimulated interest in providing a tax incentive to encourage the use of such technology. Reservoir dewatering projects have substantial costs associated with electricity and associated delivery and transmission services caused by the use of high capacity downhole pumps to accelerate the removal of formation water. Likewise, there is added electricity expense caused by operation of large capacity disposal wells configured to receive the high volume of produced water.

Once the water is removed at accelerated rates, oil and gas production, which otherwise would be uneconomic under traditional production methods, has often increased substantially. Also, increased development of natural gas from coal seams in eastern Oklahoma, which involves the dewatering of the coal seam to enhance gas production, spurred interest in this incentive. In some areas of the state, electricity sold by public utilities with certified service territories, is subject to state sales tax. To encourage oil and gas development in such areas, the Oklahoma Legislature enacted S.B. 871 (2002) to provide for the Oklahoma Corporation Commission to classify areas and reservoirs as “reservoir dewatering projects” and/or “reservoir watering units,” wherein the statutory criteria of an initial water to oil ratio

greater than or equal to five to one (5 to 1) is proved to exist.

The regulations implementing S.B. 871 provided for a conversion factor to calculate a water to gas ratio to equate to the 5 to 1 water to oil ratio. Once classified as a “reservoir dewatering project,” request is made to the Oklahoma Tax Commission for a sales tax exemption letter, which the operator uses in its relationship with the electricity supplier to gain an exemption of the state sales tax otherwise charged for sales of electricity and associated delivery and transmission services for operation of the project.

Citation: Okla. Stat. tit. 68, § 1357 (2002)

Effective date: Enacted on July 1, 2002; effective Jan. 1, 2004, for operations commencing after July 1, 2003.

Goal: To increase the use of reservoir dewatering technology associated with the drilling, exploration and production of hydrocarbon resources from certain carbonate, shale and coal seam reservoirs in the state. To provide a state tax incentive for such drilling, exploration and production enterprises through a reduction of the state’s sales tax burden on the sale of electricity and associated delivery and transmission services, which are an inherently high expense for reservoir dewatering operations.

Active supporters: Independent oil and gas producers who have been actively pursuing reservoir dewatering projects in Oklahoma have promoted this incentive. Initially this involved operators who have drilled and produced oil and gas from certain carbonate and shale reservoirs, which typically have a high water to oil ratio during initial recovery phases. Such reservoirs historically have sustained poor economic returns because of high water production and modest hydrocarbon recovery. Use of high-volume formation water recovery and disposal methods proved to increase oil and gas recovery from such fields, thus interest grew in providing tax incentives for this enterprise. Later, gas producers interested in stimulating development of natural gas from eastern Oklahoma coal seams promoted this incentive where it was possible to gain a sales tax reduction in the cost of electricity purchased for reservoir dewatering operations

Tax Exemption for Sales of Electricity Used in Enhanced Recovery Production

The tax exemption applies to the sale of electricity to the operator, specifically designated by the Oklahoma Corporation Commission, of a spacing unit or lease from which oil is produced or attempted to be produced using enhanced recovery methods, including but not limited to increased pressure in a producing formation through the use of water or saltwater if the electrical usage is associated with and necessary for the operation of equipment required to inject or circulate fluids in a producing formation for the purpose of forcing oil or petroleum into a wellbore for eventual recovery and production from the wellhead. In order to be eligible for the sales tax exemption authorized by this paragraph, the oil well production shall not exceed 10 barrels per day prior to the use of enhanced recovery methods and the total content of oil recovered prior to the use of enhanced recovery methods shall not exceed one percent (1%) by volume. The exemption authorized by this paragraph shall be applicable only to the state sales tax rate and shall not be applicable to any country or municipal sales tax rate.

Citation: Enacted HB 1498

Effective date: July 1, 2006

Goal: To encourage oil and gas development.

Tax Exemption for Secondary Recovery Properties

The incremental production from approved secondary recovery properties approved or having an initial beginning date on or after July 1, 2000, and prior to July 1, 2009, is exempt from gross production tax for a period of five years or ending upon termination of the secondary recovery process. The operator is not required to submit capital expenses or project costs.

Citation: Okla. Stat. tit. 68, § 1001 (D)(3) (2003)
Effective dates: July 1, 2000, through June 30, 2009

Tax Exemption for Tertiary Recovery

The incremental production from approved tertiary recovery projects begun on or after July 1, 1988, and before July 1, 2009, is exempt from gross production tax for a period of 10 years or expire upon project payback, whichever comes first. Project payback provides for recovery of capital and operating expenses. Administration expenses and capital expenses of pipelines built to transport carbon dioxide to a project are excluded.

Citation: Okla. Stat. tit. 68, § 1001(D)(4) (2003)
Effective dates: July 1, 1988, through June 30, 2009
Goal: To encourage operators to increase recovery by employment of tertiary recovery techniques.

Horizontally Drilled Wells

Wells qualifying for this rebate must be drilled in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) feet into the pay zone of the formation. For wells producing after July 1, 1994, and prior to July 1, 2002, the rebate shall be 24 months or ending upon payback. For wells producing after July 1, 2002, and prior to July 1, 2009, the rebate shall be 48 months or ending upon payback.

Citation: Okla. Stat. tit. 68, § 1001(E) (2003)
Effective dates: 1990 through June 30, 2009
Goal: To encourage the use of new technology and increase recovery.

Re-established Production from Non-Productive Wells

A well on which work to re-establish production commenced on or after July 1, 1994, and on or before June 30, 1997, that has not produced oil, natural gas or oil and natural gas for a period of not less than two years, as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well's status.

A well on which work to re-establish production commenced on or after July 1, 1997, and on or before June 30, 2009, that has not produced oil, natural gas or oil and natural gas for a period of not less than one year, as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well's status.

A well which, after July 1, 1997, experiences mechanical failure or loss of mechanical integrity, as defined by the Corporation Commission, including but not limited to, casing leaks, collapse of casing, loss of equipment in a wellbore or any similar event which causes cessation of production and results in a workover of the well, as evidenced by the use of a workover rig or other mechanical device being placed over the well to repair the well or equipment. Qualified wells are exempt for a period of 28 months from the date production was re-established.

Citation: Okla. Stat. tit. 68, § 1001(F) (2003)
Effective dates: 1990 through June 30, 2009
Goal: To increase production from existing fields.

Production Enhancements - Recompletions

A rebate of gross production tax may apply to the following:

(A) For production enhancement projects having a project beginning date prior to July 1, 1997, any downhole operation in an existing oil well or natural gas well that is conducted to establish production of oil or natural gas from any geological interval not currently completed or producing in such existing oil or natural gas well.

(B) For production enhancements projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2009, any downhole operation in an existing oil well or natural gas well that is conducted to establish production of oil or natural gas from any geologic interval not currently completed or producing in such existing oil or natural gas well within the same or a different geologic formation.

Production Enhancements - Workovers

A rebate of gross production tax may apply to the following:

Any downhole operation in an existing oil or natural gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or natural gas well. For production enhancement projects having a project beginning date prior to July 1, 1997, “workover” includes, but is not limited to acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing, setting bridge plugs to isolate water productive zones from oil or natural gas productive zones or any combination thereof.

For production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2009, “workover” includes, but is not limited to acidizing; reperforating; fracture treating; sand, paraffin, or scale removal or other wellbore cleanouts; casing repair; squeeze cementing; installation of compression on a well or group of wells or artificial lifts on oil, natural gas, or oil and natural gas, wells, including plunger lifts, rod pumps, submersible pumps and coiled tubing velocity strings; downsizing existing tubing to reduce well loading; downhole commingling; bacteria treatments; upgrading the size of pumping unit equipment; setting bridge plugs to isolate water production zones; or any combination thereof. “Workover” shall not mean the routine maintenance, routine repair, or like-for-like replacement of downhole equipment such as rods, pumps, tubing, packers, or other mechanical devices. Qualified production enhancements shall be exempt for a period of 28 months from the date of first sale after project completion.

Citation: Okla. Stat. tit. 68, § 1001(G) (2003)

Effective dates: July 1, 1994, through June 30, 2009

Goal: To encourage operators to increase production from existing fields by performing the described operations.

Impact: The University of Oklahoma Business Department has noted that this incentive effectively encourages enhanced recovery, new technology and drilling, while also allowing older wells to continue production.

Active Supporters: Operators

Deep Wells

For purposes of qualifying for the exemption, “depth” means the length of a maximum continuous string of drill pipe utilized between the drill bit face and the drilling rig’s kelly bushing.

Deep wells spudded between July 1, 1994, and June 30, 1997, and drilled to a depth of 15,000 feet or greater shall be exempt from gross production tax beginning with the date of first sale for a period of 28 months.

Deep wells spudded between July 1, 1997, and June 30, 2002, and drilled to a total depth of 12,500 feet or greater shall be exempt from gross production tax for a period of twenty-eight (28) months beginning with the date of first sale.

Deep wells spudded between July 1, 2002, and June 30, 2009, and drilled between a depth of 12,500 feet and 14,999 feet shall be exempt from gross production tax for a period of 28 months beginning with the date of first sale.

Deep wells spudded between July 1, 2002, and June 30, 2008, and drilled between a depth of 15,000 feet and 17,499 feet shall be exempt from gross production tax for a period of 48 months beginning with the date of first sale.

Deep wells spudded between July 1, 2002, and June 30, 2008, and drilled to a total depth of 17,500 feet or greater shall be exempt from gross production tax for a period of 60 months beginning with the date of first sale.

Citation: Okla. Stat. tit. 68, §§ 1001(H) (2003)

Effective dates: July 1, 1994, through June 30, 2009

Goal: To stimulate natural gas development in Oklahoma.

New Discovery Wells

New Discovery is defined as production of oil, natural gas or oil and natural gas from:

(A) A well, spudded or reentered prior to July 1, 1997, which discovers crude oil in paying quantities, and is located more than one mile from the nearest oil well producing from the same interval.

(B) A well, spudded or re-entered on or after July 1, 1997, and prior to July 1, 2009, which discovers crude oil in paying quantities, and is located more than one mile from the nearest oil well producing from the same interval of the same formation.

(C) A well, spudded or re-entered prior to July 1, 1997, which discovers crude oil in paying quantities beneath current production in a deeper producing formation, located more than one mile from the nearest oil well producing from the same deeper interval.

(D) A well, spudded or re-entered on or after July 1, 1997, and prior to July 1, 2009, which discovers crude oil in paying quantities beneath current production in a deeper producing interval, located more than one mile from the nearest oil well producing from the same interval of the same formation.

(E) A well, spudded or re-entered prior to July 1, 1997, which discovers natural gas in paying quantities, and is located more than two miles from the nearest natural gas well producing from the same interval.

(F) A well, spudded or re-entered on or after July 1, 1997, and prior to July 1, 2009, which discovers natural gas in paying quantities, and is located more than two miles from the nearest natural gas well producing from the same interval.

(G) A well, spudded or re-entered prior to July 1, 1997, which discovers natural gas in paying quantities beneath current production in a deeper producing interval, that is located more than two miles from the nearest natural gas well producing from the same deeper interval.

(H) A well, spudded or re-entered on or after July 1, 1997, and prior to July 1, 2009, which discovers

natural gas in paying quantities beneath current production in a deeper producing interval, that is located more than two miles from the nearest natural gas well producing from the same deeper interval.

Qualified new discovery wells shall be exempt for a period of 28 months from the date of first sales.

Citation: Okla. Stat. tit. 68, §§ 1001(I) (2003)

Effective dates: July 1, 1997, through June 30, 2009

Economically At-Risk Oil Leases

Operators may apply to the Oklahoma Tax Commission for a rebate of 6/7ths of the gross production tax upon demonstrating that they operate a lease that is economically at-risk. This particular rebate was previously in effect for calendar years 1997 and 1998 wherein it applied only to at-risk oil leases. Effective July 1, 2005, Oklahoma Statutes were amended wherein the rebate applies to both at-risk oil and gas leases.

The definition of an economically at-risk lease means any lease operated at a net profit or a net loss, which is less than the gross production tax remitted for such lease in a given calendar year. Operators of at-risk leases shall make application to the Tax Commission to certify that they meet the criteria for being at-risk. Upon approval by the tax Commission, operators shall file a claim for refund of 6/7ths of the 7% gross production tax remitted for the qualifying year. The at-risk rebate is applicable to calendar years 1997, 1998, 2005, 2006 and 2007.

Citation: Okla. Stat. tit. 68, § 1001.3a (2005)

Effective date: July 1, 2005

Three-Dimensional Seismic Technology

Operators producing oil, natural gas, or oil and natural gas from a well, the drilling of which is commenced after July 1, 2000, and prior to July 1, 2009, located within the boundaries of a three-dimensional seismic shoot and drilled based upon three-dimensional seismic technology, may apply to the Tax Commission for a rebate of gross production tax paid in the previous fiscal year upon qualifying such well with the Oklahoma Corporation Commission.

Qualified projects shall be exempt for a period of 18 months from the date of first sale for seismic shot prior to July 1, 2000. Projects shot after July 1, 2000, and prior to July 1, 2009, shall be exempt for a period of 28 months from the date of first sale.

Citation: Okla. Stat. tit. 68, § 1001 (J) (2003)

Effective dates: July 1, 2000, through June 30, 2009

Active Supporters: Oklahoma Corporation Commission and state oil and natural gas operators

Note on the Rebate Price Cap

The exemption as it pertains to each project with the exception of horizontally drilled wells and wells spud after July 1, 2005, that are drilled to a depth below 15,000 feet are contingent upon the average calendar year price of oil and natural gas. In the event the average calendar year price of Oklahoma oil or natural gas as determined by the Tax Commission should exceed the established price cap provided for by statute, the exemption for the affected product would be canceled for the applicable fiscal year period. The current price caps are \$30.00 per barrel of oil and \$5.00 per mcf of gas. The price caps are based on a calendar year average as determined by the Oklahoma Tax Commission.

Special Programs

The Oklahoma Commission on Marginally Producing Oil and Gas Wells collects and distributes information on stripper production and performs many other activities useful to the petroleum industry, especially small operators. It is funded by small oil and gas taxes from nonexempt production. Producers can opt out of paying.

The Oklahoma Energy Resources Board (OERB) was established for energy education and the remediation of abandoned oil field sites. The OERB conducts educational programs for children, and spends at least half of its funding on oil field cleanup projects. The OERB also studies remediation technology using U.S. Department of Energy funds.

Small Business Linked Deposit Program

Provides low-interest loans to qualifying businesses, including oil-related businesses.

PENNSYLVANIA

Electronic Transactions Act

In December 1999 the Pennsylvania legislature passed this version of the Uniform Electronic Transactions Act. This legislation can be considered an incentive in that it allows for the electronic submission of permit applications and required reports.

Citation: 73 P.S. § 2260.101 et seq

Effective date: Jan. 15, 2000

Grandfathering Pre-Act Wells from Bonding

Bonding is not required for any well drilled prior to April 18, 1985, the date of the Oil and Gas Act, or for on-site disposal of residual waste at these well sites.

Citation: 71 P.S. § 1934-A

Effective date: Nov. 26, 1997; no sunset

Goal: To allow operators more working capital.

Active supporters: Independent oil producers

Setback Requirements

Act 171 repealed the 330 foot setback requirement from the lease line for gas wells to be drilled in areas underlain by deep mineable coal seams.

Citation: Act 171

Effective date: Nov. 29, 2004

Goal: Allow development on smaller parcels while maintaining coordination with coal resources.

Active supporters: Gas Industry

Orphan Wells

Permit fees are waived for producers who recondition an orphan well from the Department of Environmental Protection's plugging inventory and return it to production.

Citation: Pa. Laws 223, Chapter 6, § 601(c): Waiver for Rehabilitation of Abandoned/Orphan Wells

Effective date: Aug. 1, 1992; no sunset

Goals: To bring wells back into service and remove them from the state's plugging list and to increase production while saving plugging costs for the state.

Impact: One producer has taken advantage of the program, and there have been other inquiries.

SOUTH DAKOTA

Unit Ratification

Lowers the percentage of working interest and mineral interest owners needed to ratify unit operations, from 75% to 60% in cases of compulsory unitization. This incentive is to be granted by the South Dakota Department of Environment and Natural Resources Oil and Gas Section.

Citation: HB 1014

Effective dates: July 1, 2004

Goals: To encourage additional oil and gas development by expediting unitization, which encourages increased oil and gas production through enhanced recovery project; it is good conservation practice to utilize aging, depleted vertical wells for drilling horizontal laterals to reach areas in the reservoir unaffected even after thirty or forty years of production from the vertical wells.

Active supporters: Industry

Risk Compensation

Rule specifies risk compensation allowed in cases of forced pooling and compulsory unitization. Allows cost plus 200% in compulsory pooling where interest is derived from a lease or other contract and allows cost plus 100% where interest is not subject to a lease or other contract. Allows cost plus 200% in compulsory unitization where interest is derived from a lease or other contract and allows cost plus 100% where interest is not subject to a lease or other contract. This incentive is to be granted by the South Dakota Department of Environment and Natural Resources Oil and Gas Section.

Citation: Chapter 72:10:18

Effective dates: July 1, 2004

Goals: To encourage additional oil and gas development by allowing easier formation of drilling units and unitized areas.

Active supporters: Industry

Oil Field Services

An oil field services sales tax provision provides a 1% tax exemption on oil field services. The effective tax rate is 3%.

Citation: S.D. Codified Laws Ann. § 10-45-5.3

Effective dates: July 1, 1982; amended July 1, 1991; no sunset

Goals: To maintain a competitive oil field services industry in South Dakota, and to stimulate oil and gas exploration.

Impact: This incentive is thought to have had little impact.

Voluntary Environmental Audit

Voluntary environmental audit privilege provides limited immunity for violations of environmental law, rule, regulation or permit enforced by the Department of Environment and Natural Resources which are discovered and reported to the department within 30 days. The department is prohibited

from prosecuting those violations if they are corrected within 60 days. If the violations are not corrected within 30 days, a written compliance schedule may be negotiated between the department and the operator. The department is prohibited from requesting the results of an environmental audit. The environmental audit may not be used as a civil or criminal defense if the producer:

- willfully and knowingly committed the violation;
- has a pattern of repeated violations;
- has not corrected the violation within 60 days of discovery;
- has been penalized for a violation within two years of disclosure of the present violation.

Citation: S.D. Codified Laws Ann. §§ 1-40-33 through 36; § 1-40-3

Effective date: July 1, 1996

Goal: Encourage self evaluation and improve the environment by enabling businesses to perform self-assessment and to report and voluntarily mitigate environmental problems without threat of penalty.

Active supporters: Introduced by the Senate Agriculture and Natural Resources Committee on behalf of the Department of Environment and Natural Resources; supported by the Industry and Commerce Association (ICA), the South Dakota Retailers Association and others

Natural Gas Sold Out of State

The mineral severance tax is imposed at the time natural gas is sold or consumed, whichever occurs first. This effectively eliminates severance tax on natural gas sold out of state.

Citation: S.D. Codified Laws Ann. § 10-39A-3.1

Effective dates: March 8, 1978; amended July 1, 1991

Goal: To encourage development of the natural gas industry in South Dakota.

Impact: Relatively little impact, as very little natural gas is sold out of state.

Active supporters: This program came about as a committee bill sponsored by the Department of Environment and Natural Resources

Oil and Gas Royalty Increment Status

The Commissioner of School and Public Lands can grant significantly lower state royalty rates on school and public lands, when no lease has been issued within the last 10 years, and no prospecting or exploration permit for oil and gas has been issued in the last five years. There cannot have been oil or gas production on the state-owned land or land within the immediate area. The rate may be lowered to 1/16 for the first three years of the lease, 1/12 for the second three years, and a minimum of 1/8 thereafter.

Citation: S.D. Codified Laws Ann. §§ 5-7-41 through 45

Effective date: July 1, 1993; no sunset

Goals: To encourage the development of oil and gas on public lands and to avoid any substantial impact on privately owned minerals immediately adjacent to these leased minerals.

Impact: The effectiveness of this program has not been studied, but it is believed to have been very effective in increasing the number of leases granted on certain lands that otherwise would remain unleased. According to the Department of Environment and Natural Resources, this is reflected in oil and gas auction results in Hyde and Buffalo counties.

Active supporters: Department of School and Public Lands

TEXAS

Extended Tax Rate Reductions - High Cost Gas Incentive

Extension on the tax rate reduction for high-cost natural gas wells. There is a 100% reduction for up to 120 months or until cumulative value of exemption equals 50% of drilling and completion cost. The total allowable credit for taxes paid for reporting periods before the date the application is filed may not exceed the total tax paid on the natural gas that otherwise qualified for the exemption or tax reduction and that was produced during the 24 months immediately preceding the month in which the application for certification under this section was filed with the commission. The 78th Texas legislature removed the filing deadline and made the severance tax exemption permanent.

Citation: H.B. 2424, 2425

Effective date: Sept. 1, 1999; no sunset

Goal: To increase exploration for deep/high cost gas production.

Active supporters: Railroad Commission of Texas (RRC), Texas Independent Producers and Royalty Owners, Texas Oil and Gas Association and regional oil and gas associations

Severance Tax Administration

Removal of accelerated biennial due date (“speed up”) for natural gas severance taxes and penalties for speeding up late payments. Eliminates early payment of natural gas tax in odd-numbered years.

Agency: Comptroller of Public Accounts.

Texas Oil and Gas Production Query System (PDQ)

Texas created an enhanced Internet-based production query system to provide quick and easy access to Texas oil and gas production and disposition information from 1993 through the current production month. The PDQ system provides advanced search capabilities for production and disposition data by lease, operator, field, district and county.

Effective dates: The Production Data Query System was released in June 2004, and replaced the ACTI Production Query System that was initially released in 1998.

Goal: To use the technology to provide the global community with oil and gas information as a means of promoting further domestic exploration and production.

Impact: The production query system is being widely used by the Texas Railroad Commission, operators, royalty owners and the general public to access valuable production data easily over the web.

Active supporters: Industry, royalty owners, public, Texas Railroad Commission

Flared Casinghead Gas

If an operator markets casinghead gas that had previously been released to the air (vented or flared) for 12 months or more in compliance with RRC rules and regulations, the operator may receive a severance tax exemption for that gas for the life of the oil well or lease.

Citation: § 202.058

Effective date: Sept. 1, 1997

Goal: To conserve natural gas.

Impact: This incentive pertains to a small number of wells.

Active supporters: RRC, TIPRO, TXOGA and regional associations

Two-Year Inactive Wells

This incentive mirrors the successful three-year inactive wells incentive originally passed in 1993. Any oil or gas well that has not produced in more than one month in the last 24 is eligible for a 10-year severance tax exemption upon a return to beneficial production.

Citation: §202.056

Effective dates: Sept. 1, 1997, to Aug. 31, 2009, for application for certification; Feb. 28, 2010, for certification; severance tax exemption is for up to 10 years from date of RRC certification.

Goal: To encourage the return to productivity of inactive wells, with the resulting benefits to the state economy; to reduce the need for state and industry-funded plugging.

Impact: This incentive is based on Texas' Three-Year Inactive Wells program, which enjoyed such success that at least nine states adopted similar programs, but was allowed to expire. In the year prior to the Three-Year Inactive Wells incentive, 368 wells inactive for three years or more were brought back into production. Following enactment, from September 1993 through February 1996, 6,071 wells were returned to production, with an annual average of 2,428 reactivated wells. This increase of 670% in inactive wells returned to production is valued at an estimated \$565 million at the wellhead and approximately \$1.65 billion to the economy of Texas each year. This benefit to the state is estimated to be enough to create 10,792 new jobs.

Active supporters: RRC, TIPRO, TXOGA and regional associations

The Two-Year Inactive Well Program was originally scheduled to expire in August 1999. The 76th Texas Legislature extended the program for 10 years, until February 2010. The current Two-Year Inactive Well incentive became effective Sept. 1, 1999. Following enactment, from September 1997 to June 2005, 11,543 wells were returned to production with an average of approximately 1,700 wells per year.

Marginal Gas Wells

The RRC can exempt marginal gas wells from otherwise applicable production limitations if the wells are located in gas fields without special field rules. A marginal gas well is defined in the Texas Natural Resources Code as a gas well incapable of producing more than 250,000 cubic feet of gas per day under normal operating conditions. Prior to this legislation, the TRC was precluded from exempting individual marginal wells that exist in fields with other wells capable of producing above marginal limits. This legislation replaced the RRC's requirement to limit production from gas wells producing more than 100,000 cubic feet of gas per day unless it is a marginal well in a field for which special field rules are not in effect.

Citation: H.B. 1178; amends Tex. Nat. Res. Code Ann. § 86.091

Effective date: May 16, 1997

Goal: To relieve regulatory burden of testing marginal gas wells.

Impact: Raises the production limitations on marginal gas wells and reduces industry expense associated with testing of gas wells.

Enhanced Oil Recovery

Severance tax is reduced by 50% (from 4.6% to 2.3%) for oil production from new enhanced oil recovery projects and incremental production from expanded projects for 10 years after RRC certification of production response. The RRC certification is a three-step process: first, (form H-12), the operator seeks approval and area certification for the new/expanded project; second, (form H-13), the operator seeks Railroad Commission certification that the project evidences a positive production response (an increased rate of production attributable to the project); third, (form H-14), the operator files an annual status report without which the credits are not validated. The application for positive production response certification must be filed within three years of project approval for secondary enhanced

recovery, and within five years for tertiary recovery. The 78th Texas legislature removed filing deadline and made the severance tax exemption permanent.

Citations: HB 2424

Effective dates: Effective 1989, and 1991 for expanded projects; no sunset

Goal: To encourage additional recovery of the state's oil reserves through the use of enhanced oil recovery technology, and to extend the lives of wells with the resulting benefit to the Texas economy through job creation and additional severance taxes.

Marginal Wells on State Land

The Texas School Land Board may grant a reduced royalty rate for a period of two years for marginally economic state leases. To qualify, the lease must produce an average of 15 BOPD per well, or an average of 90 Mcf of gas per day per well. Once the reduced rate is granted, royalty rates will not increase for that lease for two years. Additional reductions can be applied for at the expiration of the two-year period. This tax reduction applies when oil prices average less than \$25 per barrel.

Citation: Tex. Nat. Res. Code Ann. § 32.067, and Tex. Admin. Code tit. 31, § 9.7

Effective date: Sept. 1, 1995

Goal: To extend the lives of leases on state lands.

Paperwork Reduction

Producers may delay payment of royalties until they reach a total of \$100 or 12 months proceeds have accumulated, whichever comes first. Annual reporting for the lease may not exceed \$3,000.

Citation: H.B. 1593

Effective date: June 15, 1995

Goal: To help the state and operators avoid the costs of administering small royalty checks.

Royalty Reduction

Royalty rates are reduced for production early in the terms of leases. For submerged areas, production in years one and two earns a royalty of 20%; production in years three and four earns 22%. For uplands production, year one earns a royalty rate of 20%; production in year two earns 22.5%.

Citation: School Land Board rule

Goal: Maintain overall royalty revenue while providing an operator greater working interest revenue.

Impact: The effectiveness of this incentive has not been studied, but it is reported that more activity occurs earlier in the terms of leases since the rule took effect than prior to implementation of the incentive. The program benefits both the state and operators.

Active supporters: TIPRO, Texas Mid-Continent Oil and Gas Association, and Industry

Tax Credit for Enhanced Efficiency Equipment

Severance tax credits are available for marginal wells (an oil well that produces 10 barrels of oil or less per day on average during a month) for using equipment that reduces the energy required to produce a barrel of fluid by 10% as compared to alternative equipment. The term does not include a motor or downhole pump. The State Comptroller approves the credits. The approval is based on the condition that a Texas institution of higher education, with an accredited Petroleum Engineering program, has evaluated the equipment and determined that the equipment produces the required energy reduction. The credit is in an amount equal to the lesser of either 1) 10% of the cost of the equipment or 2) \$1,000 per well. The number of applications the State Comptroller may approve each state fiscal year may not exceed a number equal to one percent of the producing marginal wells in Texas on September

1 of that fiscal year.

Citation: HB 2161 adopted by the 79th Legislature; Subchapter B, Chapter 202 Tax Code, §202.061.

Effective dates: The enhanced efficiency equipment installed in or on a qualifying marginal well must be purchased and installed no earlier than Sept. 1, 2005, or later than Sept. 1, 2009.

Goal: To encourage energy conservation of marginal oil wells.

Active supporters: Oil and gas industry and industry associations

Orphaned Well Reduction Program

An orphaned well under this program is defined as a well that has been inactive for 12 months where the operator of the well no longer has a current registration with the Commission as required by Texas statute. Under the program, a prospective new operator may nominate the well and be given a 30-day period during which they can (through visual means and non-invasive testing methods) inspect the well to determine whether the person wishes to assume operatorship of the well. If so, the operator provides evidence of a good-faith claim to the right to produce minerals from the well, files paperwork with the Commission to assume operatorship of the well, and remits a \$250 fee. If an orphaned well is taken over by a new operator under this program during the effective period (i.e., 01/01/06 - 12/31/07), the operator is entitled to receive:

1. a non-transferable exemption from severance taxes for all future production from a well under Tax Code §202.060;
2. a non-transferable exemption from the fees provided by Natural Resources Code §§81.116 and 81.117 (oil and gas regulatory fees paid into the Oilfield Cleanup Fund based on production) for all future production from the well; and
3. a payment from the Commission in an amount equal to the depth of the well times \$0.50/foot if, not later than the third anniversary of the date the operator acquires the well, the operator brings the well back into continuous active operation or plugs the well in accordance with Commission rules. (Note that payments under this program are made in the order that operators qualify for them. The Commission is limited to total payments of \$500,000 under this program per fiscal year. Operators may not receive more than one payment for a particular well, nor may they receive aggregate payments in excess of the amount of financial security posted under Natural Resources Code §91.104.)

Citation: HB 2161 adopted by 79th Legislature; Texas Natural Resources Code §89.047 (and such rules as may be necessary to be adopted to implement).

Effective dates: Jan. 1, 2006, through Dec. 31, 2007

Goal: To encourage continued production of viable wells by responsible operators, and to reduce the population of orphan wells for which the Oilfield Cleanup Fund will bear the cost of plugging.

Active supporters: Commission staff and industry

Tax Credits for Qualifying Low-Producing Wells

Chapter 201 of the Tax Code was amended to provide three levels of tax credits on gas production from qualified low-producing gas wells for any given month, depending on the State Comptroller's average taxable oil and gas prices, adjusted to 2005 dollars, based on applicable price indices of the previous three months. An operator of a qualifying low-producing gas well would be entitled to 1) a 25% tax credit if the average taxable gas price were more than \$3.00 per Mcf but not more than \$3.50, 2) a 50% tax credit if the price were more than \$2.50 per Mcf but not more than \$3.00 and three) a 100 percent tax credit if the price were \$2.50 or less. The bill defines a qualifying low-producing gas well as a well that averages, over a three-month period, 90 Mcf per day or less.

Chapter 202 of the Tax Code was amended to provide three levels of tax credits on oil production from the qualified low-producing oil leases for any given month, depending on the State Comptroller's average taxable oil prices, adjusted to 2005 dollars, based on applicable price indices of the previous three months. An operator of a qualifying low-producing oil lease would be entitled to 1) a 25% tax credit if the average taxable oil price were more than \$25.00 per barrel but not more than \$30.00, 2) a 50% tax credit if the price were more than \$22.00 per barrel but not more than \$25.00, and 3) a 100 percent tax credit if the price were \$22.00 or less. The bill defines a qualifying low-producing oil lease as a lease that averages, over a three-month period, less than 15 barrels per day per well or 5% recoverable oil per barrel of produced water per well. The bill would require a \$100 filing fee to the State Comptroller for oil leases that qualify under the 5% recoverable oil requirement.

This new statute limits tax credits for both low-producing oil leases and gas wells only to wells currently paying full tax rates (it excludes those wells operating under existing tax incentive programs). Further, the bill does not extend tax credits to casinghead gas and condensate production.

The State Comptroller's office must certify and publish in the Texas Register, each month, the average taxable prices of oil and gas, adjusted to 2005 dollars, using applicable price indices during the previous three months. A taxpayer must apply to the State Comptroller's Office for tax credits within the statutory time limit and the tax credits would only apply to crude oil and natural gas produced on or after Sept. 1, 2005.

Citation: House Bill 2982, § 201.058 and 202.059, Texas Tax Code

Effective dates: Sept. 1, 2005; no sunset

Goal: To make low-producing wells economical to enhance recovery of the State's minerals.

Active supporters: Texas Oil and Gas Association, Texas Independent Producers and Royalty Owners, Texas Alliance of Energy Producers, American Royalty Council, and Industry

Tax Incentive for Sequestration of Anthropogenic CO₂

This bill provides a tax rate reduction on oil produced from enhanced recovery (EOR) projects using anthropogenic carbon dioxide (CO₂). The bill requires the Railroad Commission to issue certification if the CO₂ used in the EOR project is to be sequestered in a reservoir productive of oil or natural gas; the Texas Commission on Environmental Quality (TCEQ) issue the certification if the CO₂ used in the EOR project is to be sequestered in a formation other than a reservoir productive of oil or natural gas; and both the Railroad Commission and TCEQ to issue certifications if the CO₂ is sequestered in both a formation not productive of oil or natural gas and a reservoir of oil or natural gas.

Citation: House Bill 3732, §202.0545, Texas Tax Code

Effective dates: Sept. 01, 2007, until the later of the 7th anniversary of the date the Texas Comptroller of Public Accounts first approved an application for a tax rate reduction or the effective date of a final rule adopted by EPA regulating CO₂ as a pollutant.

Goal: To encourage the capture, use in EOR, and sequestration of anthropogenic carbon dioxide.

Active supporters: Governor of Texas, Clean Coal Technology Foundation of Texas Railroad Commission of Texas

Tax Incentive for Reuse/Recycling of Fracturing Water

Provides for an exemption from sales, excise, and use taxed, tangible personal property specifically used to process, reuse, or recycle wastewater that will be used in fracturing work performed at an oil or gas well.

Citation: House Bill 4, §151.355, Texas Tax Code
Effective date: June 15, 2007
Goal: To encourage and support recycling of water using hydraulic fracturing.
Active supporters: Cities in Barnett Shale area, environmental associations

UTAH

Workovers/Recompletions

A working interest owner who pays for all or part of the expenses of a recompletion or workover is entitled to a tax credit equal to 20 percent of those expenses. The tax credit may not exceed \$50,000 per well during each calendar year until Dec. 31, 1994, and \$30,000 per well during each calendar year, beginning Jan. 1, 1995.

Citation: Utah Code Ann. § 59-5-102(6)
Effective date: Jan. 1, 1990; no sunset
Goal: To encourage investment in and continued production of wells, increase recovery, delay abandonment, establish new production and provide for economic gains in areas of the state which have oil and gas activity. Since the cost of a workover is only a fraction of the cost to drill a new well, a workover incentive is expected to extend the producing life of wells in the Uintah Basin, thereby creating jobs and tax revenue in that region.
Impact: This is an effective and widely used incentive.
Active supporters: Petroleum industry, county and state governments

Graduated Severance Tax Rate

For oil, the severance tax rate is 3% up to and including the first \$13 per barrel, and 5% of the value exceeding \$13 per barrel. The severance tax rate for natural gas is 3% for the first \$1.50 per Mcf, and 5% of value above \$1.50.

Citation: Utah Code Ann. § 59-5-102(2)
Effective date: Jan. 1, 1992; no sunset
Goal: To provide tax relief during periods of low prices, encouraging continued production.

Marginal/Stripper Wells

Stripper wells are tax exempt unless the exemption prevents the severance tax from being treated as a deduction for federal tax purposes. Stripper wells are defined as wells which produce an average of less than 20 BOPD for one year, or 60 Mcf or less of natural gas per day for 90 consecutive days.

Citation: Utah Code Ann. § 59-5-102(5)(b)
Effective date: Jan. 1, 1984; no sunset
Goal: Encourage continued production and avoid premature abandonment of marginal wells.

Wildcat Wells

No severance tax is imposed on the first 12 months of production from wildcat wells started after Jan. 1, 1990.

Citation: Utah Code Ann. § 59-5-102(5)(c)

Effective date: Jan. 1, 1990; no sunset

Goal: To encourage exploration activity.

New Wells

The first six months of production from new wells started after Jan. 1, 1984, but before Jan. 1, 1990, and development wells started after Jan. 1, 1990, is exempt from severance taxes.

Citation: Utah Code Ann. § 59-5-102(5)(d)

Effective dates: Jan. 1, 1984, (new wells); no sunset, and Jan. 1, 1990 (development wells); no sunset

Goal: To encourage exploration activity.

Enhanced Recovery

A 50% reduction in severance tax is available for the incremental production achieved from an enhanced oil or gas recovery project.

Citation: Utah Code Ann. § 59-5-102(7)

Effective date: Jan. 1, 1996; no sunset

Goals: Encourage initiation of enhanced recovery projects, use of marginal wells, increase production and avoid premature abandonment of marginal wells.

Active supporters: Industry and state government

VIRGINIA

Direct Sales of Natural Gas by Producers

Producers of natural gas may sell directly to as many as 35 commercial and industrial customers without having to become certified as a public utility. Certain public schools are also customers not to be classified as a public utility. The customer limit was raised during the 1997 Virginia General Assembly session from a 10-customer limit. The number of schools are not limited and it does not count against the “fewer than 35” requirement.

Citation: Va. Code Ann. § 56-265.1 (4) (amended by 2004 Va. Acts 748,1028)

Effective dates: 1990, amendment effective July 1, 2004

Goal: To allow gas producers to sell natural gas to commercial, industrial and public schools in areas not served by local gas utilities.

Impact: Several companies have extended service under this program.

Active supporters: Virginia gas producers, local economic development officials

Escrow of Coalbed Methane Conflicting Ownership Claims

Established under section 45.1-361.22 of the Virginia Gas and Oil Act, the Virginia Gas and Oil Board may escrow proceeds from a coal seam natural gas production well in a unit where there are conflicting claims to ownership of the gas. The Board pays the escrowed proceeds when there is a final decision of a court of competent jurisdiction or agreement among conflicting claimants addressing the ownership of the gas.

Citation: Va. Code Ann. § 45.1-361.22

Effective date: July 1, 1990; no sunset

Goals: To allow production of coal seam natural gas in areas with conflicting claims of ownership.
Impact: The Virginia Department of Mines, Minerals and Energy has determined that this section of the Virginia Code has been one key factor that has led to increases in coal seam natural gas production from nominal levels in 1989 to nearly 70 BCF/year.
Active supporters: The Virginia Oil and Gas Association, and coal seam natural gas operators

Coalfield Employment Enhancement Tax Credit

One cent per million BTUs of coal seam natural gas production is credited to the producer.

Citation: Va. Code Ann. § 58.1 - 439.2

Effective dates: July 1, 1996, to Jan. 1, 2008

Goals: To preserve and expand the coal industry and related jobs, and to encourage production of coal seam natural gas.

Impact: Production of coal seam natural gas has increased since this incentive was passed. It is not known to what extent this incentive affected the increase.

Active supporters: Virginia's coal producers

Sales and Use Tax Exemptions

Raw materials, fuel, power, energy, supplies, machinery, tools and repair/replacement parts used directly in the drilling, extraction, refining or processing of natural gas or oil and reclamation of the well area are exempt from the 4% state sales and use tax, and the 1% local sales and use tax. Exemption includes all phases of production and processing, including gathering, until gas is pipeline quality.

Citation: Va. Code Ann. § 58.1-609.3(12)

Effective dates: July 1, 1994, through June 30, 2011

Goal: To stimulate investment in Virginia by providing sales and use tax exemptions similar to exemptions offered in other Appalachian Basin states.

Impact: Initial, onetime revenue impact for Virginia's economy is estimated at \$1 million. The 1996 impact is estimated at \$250,000 to \$325,000 (approximately \$2,300 to \$2,700 per conventional well, and \$1,400 to \$1,800 per coalbed methane well). As a result, some producers have increased investment in Virginia.

Active supporters: Virginia Oil and Gas Association

Virginia Dept. of Mines, Minerals and Energy/Division of Mineral Resources

The Division of Mineral Resources conducts research and provides information about the state's gas and oil resources for Virginia's gas and oil industry. The division maintains all information on coreholes, geologic features in gas and oil bearing areas, and a database on wells drilled in the Commonwealth.

Effective date: Virginia's geological survey was started in 1835

Goal: Enhance the development and conservation of energy and mineral resources in a safe and environmentally sound manner to support a more productive economy.

Impact: Customers continually rate the services of the division as very useful.

Active Supporters: Gas and oil operators

Consent to Stimulate Coalbed Methane

The Virginia Gas and Oil Act requires a producer of coal seam natural gas to obtain consent from the coal operator of each coal seam located within 750 horizontal feet of a well or 100 vertical feet of any coal seam to be stimulated. A 1997 amendment to this requirement provides that this consent shall be deemed to be granted for any tract where title to the coal is held by multiple owners who have not leased the tract for coal development when the gas operator obtains consent from the co-owners hold-

ing a majority interest in the tract.

Citation: Va. Code Ann. § 45.1-361.29.F.2 (amended by 1996 Va. Acts 759 and 765)

Effective date: July 1, 1997

Goal: To allow production of coal seam natural gas when the consent to stimulate cannot be obtained from all co-owners of a tract of coal.

Impact: It is too early to determine the effects of this change.

Active Supporters: Virginia Oil and Gas Association

WEST VIRGINIA

Severance Tax Exemption

Imposes a tax equal to 5% of the gross value produced for the privilege of severing natural gas or oil. Effective taxable periods beginning on or after Jan. 1, 2000. An exemption from the severance tax is granted for natural gas provided free to surface owners. The exemption is granted to low-volume wells, producing less than 5 Mcf of natural gas per day or oil wells that produced an average of less than one-half barrel of oil per day during the calendar year immediately preceding a given taxable period. Natural gas or oil produced from a well that has not produced marketable quantities for five consecutive years immediately preceding the year in which the well is placed back into production and begins producing marketable quantities is also exempted for a maximum of 10 years.

Citation: H.B. 2749

Effective date: May 12, 1999

Goal: To maintain the production of marginal oil and gas wells.

Bona Fide Future Use Program

Wells that have not been producing in the previous 12 months can be designated as having a “bona fide future use.” Such a designation would keep idled wells from being deemed abandoned and avoid subjecting them to a plugging obligation.

Citation: WV Code Chapter 22, Article 6-19

Effective date: July 1, 1993

Goal: To stimulate returning existing, idled wells to production and encourage new wells.

Direct Use Sales Tax Exemption

When the exemption from sales tax for contractors was removed in 1989, subcontractors were included for the oil and gas industry, even though contract drillers were still exempt from sales tax on purchases used directly in the production of oil and gas. The 1994 Legislature clarified in Senate Bill 328 that this “direct use” exemption was available also to oil and gas subcontractors.

Effective dates: 1989 and 1994

WYOMING

Tertiary Production

Tertiary production resulting from projects certified by the Wyoming Oil and Gas Conservation Commission (WOGCC) after March 31, 2003, and before March 31, 2008, is exempt from the 2% of severance taxes imposed by Wyo. Stat. 39-14-204(a)(iii) for a period of five years from the date of first tertiary production. An exemption under this subsection shall not be granted in those months when the price received by the producer for the tertiary production equals or exceeds \$27.50 per barrel. A taxpayer claiming a tax reduction under this subsection is prohibited from claiming a tax reduction provided by subsection (f) or (g) of this section.

Citation: Wyo. Stat. § 39-14-205 (c)

Effective dates: March 31, 2003, through March 31, 2008

Goal: To encourage discovery of new reserves and continued production of older reservoirs. The May 1, 2000, amendment's goal was the exclusion of coalbed methane wells.

Impact: Two new projects initiated in 2005.

Active Supporters: WOGCC

Idle Wells

A five-year severance tax reduction from 6% to 1.5% is available on oil produced from previously idle wells. Wells must not have produced for at least the two consecutive years prior to Jan. 1, 1995. This tax reduction applies for the first 60 months of renewed production or until the average price of oil reaches a level of \$25 per barrel averaged over the preceding six months, whichever occurs first.

Citation: Wyo. Stat. § 39-14-205(h)

Effective date: Jan. 1, 1995; no sunset

Impact: 115 wells were restored to production in the 1994 - 2003 time period resulting in \$1.6 million in severance and ad valorem taxes.

Active supporters: Petroleum industry, WOGCC and pro-business legislators

Marginal/Stripper Wells

Wells which produce an annual average of less than 15 BOPD while the price of oil is less than \$20 per barrel are taxed at 4% (reduced from 6%). When the price of oil is \$20 or more, wells producing 10 BOPD or less receive the 2% tax reduction.

Citation: Wyo. Stat. § 39-14-205(a)(xx)(A)(B)

Effective date: Jan. 1, 1995; no sunset

Goal: To encourage continued production from low-volume, marginal wells.

Impact: Wyoming recognizes that high severance tax rates contribute to premature abandonment. Stripper production was 16.4% of total state production in 2004, when 8,487,256 barrels of oil qualified for this reduction. The importance of this incentive continues to grow as fields continue to mature.

Active supporters: Petroleum industry, WOGCC and pro-business legislators

Environmental Audit Privilege

This privilege gives oil and gas companies complete immunity from fines and penalties of the Department of Environmental Quality for violations that are reported to the department along with remediation plans.

Citation: Wyo. Stat. §§ 35-11-1105 and 1106

Effective date: Feb. 18, 1995

Goal: To encourage environmental compliance.

Active supporters: Mineral industry, other Wyoming industries and pro-business legislators

State-Funded Demonstration Project

The state of Wyoming, concerned with the economic and employment costs of abandonment of marginal wells, has funded a demonstration project which should benefit wells in danger of abandonment. The new technology is a hydraulic fracture technique for sand-stone reservoirs. This technique is expected to produce oil economically from shallow sandstone formations, reducing the rate of abandonment for many marginal wells.

Effective date: Rock Creek Enterprises conducted the demonstration in April 1996.

Goal: To encourage production from marginal wells as a result of more efficient recovery.

Federal Incentive Programs

BUREAU OF LAND MANAGEMENT

Royalty Rate Reduction for Stripper Oil Property

The operator or owner of a federal stripper oil property that is producing less than 15 BOPD average qualifies for a royalty rate reduction from the normal royalty rate of 12.5%. This royalty rate reduction is based on a sliding scale.

Citation: 61 FR 4748, 4750; 43 C.F.R. §§ 3103.4-1, 3103.4-4

Effective date: 1992; extended indefinitely in 1997

Goal: To extend the economic life of property and enhance production.

Suspended: Feb. 1, 2006

Heavy Oil Royalty Rate Reduction

Operators of properties that produce “heavy oil,” crude oil with a gravity of less than 20 degrees API (American Petroleum Institute), are eligible for a royalty rate reduction. The royalty rate reduction is based on a sliding scale for qualifying heavy oil properties. The sliding scale is intended to somewhat offset the reduced prices paid for oil as gravity decreases. For example, at 20 degrees API gravity the royalty rate is 12.5%, which can be reduced to a minimum of 0.5% based on the corresponding API gravity of the oil.

Citation: 61 FR 4748, 4750; 43 C.F.R. §§ 3103.4-1, 3103.4-3

Effective date: Feb. 8, 1996

Goals: To extend the economic life of the property and to enhance production.

Impact: The BLM reports that 30 California applicants qualified during the first eight months the incentive was in effect. Applicants in Louisiana, Nevada and Wyoming also have taken advantage of this incentive.

Suspended: Nov. 1, 2005

Sec 343 of the Energy Policy Act of 2005 provides for a royalty rate reduction when the spot price of WTI is less than \$15/barrel or Henry Hub gas is less than \$2.00/mmbtu for 90 consecutive trading days and production is less than 15/bo/well/day or 90 mmbtu/well/day for the three most recent production months, then royalty would be 5%.

Fuel Substitution

A royalty rate reduction is available for operators who choose to burn clean fuel for on-lease beneficial use. The conversion for this exchange is BTU for BTU (1:1).

Note: Any operator can request a royalty rate reduction on a federal lease property. A royalty rate reduction will be granted only on an economic basis after strict scrutiny.

DEPARTMENT OF COMMERCE

Emergency Oil and Gas Guaranteed Loan Program

Provides \$500 million in loan guarantee authority to a board comprised of the Secretary of Commerce and the chairmen of the Securities and Exchange Commission and the Federal Reserve. Individual loans for as much as \$10 million are eligible for guarantees of up to 85%. The authority to guarantee loans under this program expired on Dec. 31, 2001. There are no minimum loan guarantee amounts and all loans must be repaid no later than Dec. 31, 2010.

Citation: Public Law 106-51; 13 CFR Chapter V, Part 500; 64 FR 57946; 15 U.S.C.S. § 1841

Effective date: Dec. 27, 1999

Eligibility: Any independent oil and gas company that is a small business concern under Section 3 of the Small Business Act that is an oil field service company whose main business is providing tools, products, personnel and technical solutions on a contractual basis to exploration and production operators that drill, complete wells and produce, transport, refine and sell hydrocarbons and their by-products as its main commercial business. The company also must have experienced layoffs, production losses or financial losses since the beginning of the oil import crisis, after Jan. 1, 1997.

Goal: To assist the independent oil and gas producers in the United States with recovery from the low price period, while sustaining domestic oil production.

INTERNAL REVENUE SERVICE

Internal Revenue Service

Income tax provisions directly affecting the domestic petroleum industry are summarized below. (Caution: a number of bills were pending in Congress that may modify some of these provisions. Check for updates at www.irs.gov.)

The President signed into law the Energy Policy Act of 2005 (HR 6) on August 8, 2005. Income tax provisions affecting the domestic petroleum industry are summarized below:

Energy Policy Act of 2005 (HR 6)

House Bill Section 1323. Temporary expensing for equipment used in refining of liquid fuels - Primary Code Section 179C. Under present law, petroleum refining assets are depreciated over a 10-year recovery period using the double declining balance method. The new provision provides a temporary election to expense 50% of the cost of qualified refinery investments. Any cost so treated is allowed as a deduction for the taxable year in which the qualified refinery property is placed in service. The remaining 50% is recovered under present law.

Qualified refinery property includes assets, located in the United States, used in the refining of liquid fuels:

- the original use commences with the taxpayer and is placed in service before Jan. 1, 2012;
- which meets all applicable environmental laws in effect on the date such portion was placed in service;
- which increase the capacity of an existing refinery by at least 5% or increase the throughput of qualified fuels (as defined in section 45K(c)) by at least 25%.

- with the respect to the construction of which there is a binding contract before Jan. 1, 2008.

In the case of self-constructed property, the construction of which began after June 14, 2005, and before Jan. 1, 2008.

The 5% capacity requirement refers to the output capacity of the refinery, as measured by the volume of finished products other than asphalt and lube oil, rather than input capacity as measured by rated capacity.

The expensing election is not available with respect to identifiable refinery property built solely to comply with federally mandated projects or consent decrees.

For example, a taxpayer may not elect to expense the cost of a scrubber, even if the scrubber is installed as part of a larger project, if the scrubber does not increase throughput or increased capacity to accommodate qualified fuels and is necessary for the refinery to comply with the Clean Air Act. This exclusion applies regardless of whether the mandate or consent decree addresses environmental concerns with respect to the refinery itself or the refined fuels.

As a condition of eligibility for the expensing of equipment used in the refining of liquid fuels, the provision provides that a refinery must report to the IRS concerning its refinery operations, (e.g. production and output).

Effective Date: The provision is effective for property placed in service after August 8, 2005, the original use of which begins with the taxpayer, provided the property was not subject to a binding contract for construction on or before June 14, 2005.

House Bill Section 1325

Natural gas distribution lines treated as 15-year property - Primary Code Section 168 (e)(3)(E)(viii). Gas distribution lines must be depreciated over 20 years under present law.

The new legislation establishes a statutory 15-year recovery period and a class life of 35 years for distribution lines put in service after April 11, 2005. The provision amended Code Section 168(e)(3) to allow 15-year treatment to any natural gas distribution line the original use of which occurred after April 11, 2005, and before Jan. 1, 2011. The provision does not apply to any property which the taxpayer or related party had entered into a binding contract for the construction thereof or self-constructed on or before April 11, 2005.

Property not meeting the qualified criteria would continue to be depreciated over 20 years.

Effective Date: Effective for property, the original use of which begins with the taxpayer after April 11, 2005, which is placed in service after April 11, 2005, and before January 1, 2011. The provision does not apply to property subject to a binding contract on or before April 11, 2005.

House Bill Section 1326

Natural gas gathering lines treated as seven-year property - Primary Code Section 168(e)(3)(C)(iv).

The uncertainty regarding the appropriate recovery period of natural gas gathering lines has resulted in litigation between taxpayers and the Service.

The new legislation establishes a statutory seven-year recovery period and a class life of 14 years for natural gas gathering lines. In addition, no adjustment will be made to the allowable amount of de-

preciation with respect to this property for purposes of computing a taxpayer's alternative minimum taxable income. The provision does not apply to any property which the taxpayer or related party had entered into a binding contract for the construction thereof on or before April 11, 2005, or in the case of self-constructed property, has stated construction on or before such date.

A natural gas gathering line is defined to include any pipe, equipment, and appurtenance that is

- (1) determined to be a gathering line by the Federal Energy Regulatory Commission, or
- (2) used to deliver natural gas from the wellhead or a common point to the point at which such gas first reaches
 - a. a gas processing plant,
 - b. an interconnection with an interstate transmission line,
 - c. an interconnection with an intrastate transmission line,
 - d. a direct interconnection with a local distribution company, a gas storage facility, or an industrial consumer.

Effective Date: Amendments made by this section shall apply to any natural gas gathering line the original use of which commences with the taxpayer and placed in service after April 11, 2005.

House Bill Section 1328

Determination of small refiner exception to oil depletion deduction - Primary Code Section 613A(d)(4).

Oil and gas producers are classified as either independent producers or integrated companies. A producer is an independent producer only if its refining and retail operations are relatively small. Under present law an independent producer may not have refining operations, the runs from which exceeded 50,000 barrels on any day in the taxable year during which independent producer status is claimed. A refinery run is the volume of inputs of crude oil (excluding any product derived from the oil) into the refining stream.

The bill increases the current 50,000-barrel per day limitation to 75,000. In addition, the bill changes the refinery limitation claiming independent status from a limit based on actual production to a limit based on average daily production for the taxable year. Accordingly, the average daily refinery runs for the year may not exceed 75,000 barrels. For this purpose, the taxpayer calculates average daily refinery runs by dividing total refinery runs for the taxable year by the total number of days in the taxable year.

Effective Date: This provision is effective for taxable years ending after Aug. 8, 2005.

House Bill Section 1329

Amortization of geological and geophysical expenditures - Primary Code Section 167(h)

Courts have held that geological and geophysical expenditures (G&G costs) are capital, and therefore are allocable to the cost of the property acquired or retained.

Revenue Rulings 77-188 and 83-105 provided further guidance regarding the definition and proper tax treatment of G&G costs.

The new legislation allows geological and geophysical costs amounts in connection with oil and gas exploration in the United States to be amortized over two years. In the case of abandoned property, the remaining G&G basis may no longer be recovered in the year of abandonment of a property as all

G&G basis is recovered over the two-year amortization period.

G&G costs incurred prior to Aug. 8, 2005, are not covered in this provision. The provision also does not cover foreign G&G costs. These costs will continue to be capitalized and allocated to the property acquired or retained.

Effective Date: The provision is effective for geological and geophysical costs paid or incurred in taxable years beginning after Aug. 8, 2005.

House Bill Section 1346

Renewable Diesel - Primary Code Section 40A

The Act amends Code Section 40A (relating to biodiesel used as fuel) by extending its provisions to renewable diesel. It provides for an income tax credit reportable as a General Business Credit for renewable diesel used as a fuel in a trade or business, or sold at retail to another person and put in the fuel tank of that person's vehicle. Renewable diesel will be treated in the same manner as biodiesel except that

- the rate of credit with respect to renewable diesel will be \$1.00 per gallon sold or used rather than 50 cents.
- Subsections (b)(3) and (b)(5) in regard to agri-biodiesel shall not apply.

Biodiesel is an alternative to petroleum-based diesel fuel and is made from renewable resources such as vegetable oils or animal fats. Biodiesel contains no petroleum but can be blended with petroleum diesel into a biodiesel blend.

The term 'renewable diesel' means diesel fuel derived from biomass or any product thereof using a thermal depolymerization process which meets EPA and the American Society of Testing and Materials requirements.

The term 'biomass' means any organic material other than oil and natural gas (or any product thereof) and coal (including lignite) or any product thereof.

Thermal depolymerization (TDP) is a process for the reduction of complex organic materials (usually waste products of various sorts, often known as biomass) into light crude oil.

Effective Date: The effective date for this amendment shall apply with respect to fuel sold or used after Dec. 31, 2005, and before Dec. 31, 2008.

House Bill Section 4297

Tax Increase Prevention and Reconciliation Act (TIPRA) of 2005 (P.L. 109-222), on May 17, 2006. The Income tax provision affecting the domestic petroleum industry:

(Caution: a number of additional bills were pending in Congress that may modify some of these provisions. Check for updates at www.irs.gov.)

Code Section 167(h) Extends the two-year amortization period for G&G costs to five years for certain major integrated oil companies. Applies only to integrated oil companies that have an avg. daily worldwide production of crude oil of at least 500,000 barrels for the taxable year, gross receipts in excess of \$1 billion in the last taxable year ending during calendar year 2005, and an ownership interest in a crude oil refiner of 15% or more.

Tax Relief and Health Care Act of 2006 (P.L. 109-342)

Income tax provisions affecting the domestic petroleum industry.

Code Section 613A The provision extends for two years the percent-law taxable income limitation suspension provision for marginal production (through taxable years beginning on or before Dec. 31, 2007).

The Tax Relief and Health Care Act of 2006 provides an extension through 2008 of numerous energy provisions that will expire at the end of 2007. The Tax Relief and Health Care Act of 2006 also contains a package of other energy provisions.

A credit for electricity produced from certain renewable resources

Extension of credit for electricity produced from certain renewable resources.

Extension of credit to holders of clean renewable energy bonds

Modification of the clean coal gasification tax credit

Extension of deduction for energy efficient commercial buildings

Extension of credit for new energy efficient homes

Extension of credit for residential energy efficient property

Extension of energy credit for businesses producing electricity from solar energy, fuel cells or micro-turbines

Extension of reduced excise tax rate for qualified methanol or ethanol fuel produced from coal.

Expands qualified expenditures permitted from the Leaking Underground Storage Tank (LUST) Trust Fund.

Modification of the coke and coke gas production tax credit

Final Regulations that may be of interest that were issued during 2007

1. Depreciation of MACRS property involved in a like-kind exchange (T.D. 9314)

Effective date: Dec. 20, 2006

MINERALS MANAGEMENT SERVICE

Federal Oil and Gas Royalty Simplification and Fairness Act of 1996

The Royalty Simplification and Fairness Act (RSFA) streamlines the audit and appeal process, shortens records retention requirements, alters reciprocal interest requirements with industry receiving interest on overpayments, limits the liability period to seven years and specifies liable parties and reduces reporting requirements through prepayments of royalties on marginal properties.

Citation: 30 U.S.C.S. §§ 1701 et seq.; 104 H.R. 1975

Effective date: Provisions are effective beginning Sept. 1, 1996

Goal: To decrease the time required for collections owed to the U.S. government, to lessen burdensome and costly record keeping, to quicken resolution of money disputes and correction of underpayment/overpayment problems, and to provide a more cost-effective approach to royalty management by streamlining and simplifying certain royalty requirements and practices.

Impact: The RSFA amends portions of the Federal Oil and Gas Royalty Management Act of 1982 to provide that owners of operating rights in a federal oil and gas lease are primarily liable for royalty pay-

ments on their portions of their lease, and that owners of record title for such leases are secondarily liable. This required the collection of data connecting the lessees with the parties who are currently paying and reporting on federal leases, an increased administrative burden on industry and government. Active supporters: U.S. Sens. Don Nickles and Pete Domenici; U.S. Reps. Ken Calvert, Calvin Dooley, Billy Tauzin and Frank Lucas; former U.S. Sen. Frank Murkowski; and former U.S. Rep. Bill Brewster

The following incentives are available only for the Gulf of Mexico OCS.

Deep Gas Incentive

This incentive is for the exploration and development of deep gas deposits in shallow water (less than 200 meters). The program provides, for leases issued from 2001 through 2003, a royalty suspension on the first 20 BCF of gas produced from a new deep gas reservoir 15,000 feet TVD or deeper. The incentive is specified in the Notice of OCS Lease Sale and in the lease instrument. The Final Rule of Relief or Reduction in Royalty Rates-Deep Gas Provisions was published on Jan. 26, 2004, with a Technical Amendment published on April 30, 2004. The rule provides, for leases issued before 2001 and after 2003, a royalty suspension volume (RSV) up to 15 BCF on gas produced from a well completion 15,000 to less than 18,000 feet TVD and up to 25 BCF for 18,000 feet TVD or deeper. The maximum RSV per lease is 25 BCF. The rule also provides a royalty suspension supplement (RSS) up to five BCFE for unsuccessful wells drilled to a target reservoir 18,000 feet TVD or deeper. The RSS must be applied to royalties due on future oil and gas production on the same lease. Two RSS's are available per lease and they must be earned prior to production from a deep well. Lessees of leases issued from 2001 through 2003 had an option to replace, before Sept. 1, 2004, the deep gas royalty relief terms in the lease instrument with the terms in the final rule.

Citation: 30 CFR 203.0 AND 203.40-48

Effective date of final rule: May 3, 2004

Goal: Exploration and development of offshore deep gas resources.

End-of-Life Leases

A lease operator may apply for end-of-life royalty relief if royalty payments exceed 75% of net revenue for a 12-month period. The royalty rate will be reduced by one-half. This incentive is applicable to producing leases in the Gulf of Mexico and Pacific Outer Continental Shelf (OCS).

Citation: 30 CFR 203.50-56

Effective date: February 17, 1998

Goal: Extend the economic life of producing leases.

Eligible Leases

Under the Deepwater Royalty Relief Act of Nov. 28, 1995 royalty relief (no application required) is provided for deepwater leases that were issued from 1996 through 2000. A royalty suspension volume is assigned, based on water depth, to a field rather than each lease. Royalty suspension volumes are 17.5 million BOE for water depths from 200 to 399 meters, 52.5 million BOE from 400 to 799 meters, and 87.5 million BOE for 800 meters and greater.

Citation: 30 CFR 260.110(d)

Effective dates: Feb. 17, 1998; updated as 30 CFR 260.112-117, effective March 26, 2001

Goal: To encourage development of deepwater resources.

Royalty Suspension Leases

An automatic royalty suspension volume is provided for post 2000 deepwater leases as specified in the Notice of OCS Lease Sale and the lease document. The royalty suspension volumes in a recent lease sale were 5 million BOE for water depths from 400 to 799 meters, 9 million BOE for water depths from 800 to 1,599 meters and 12 million BOE for 1,600 meters and greater.

Citation: 30 CFR 260.120-124

Effective date: March 26, 2001

Goal: To encourage the development of deepwater resources.

Subsalt Lease Term Extension

This incentive encourages drilling of wells with subsalt hydrocarbon objectives. The program provides up to a two-year extension of the five-year primary lease term, thus allowing the operator additional time to refine subsalt imaging techniques and to process and interpret such imaging.

Citation: Notice to Lessees and Operators No. 2000-G22

Effective date: Dec. 22, 2000

Goal: Development of offshore subsalt resources.

Deepwater Discretionary Royalty Relief for Pre-Act (Deepwater Royalty Relief Act of November 28, 1995) and Post 2000 Leases

This rule provides a royalty suspension incentive that applies specifically to oil and gas fields and projects that would otherwise be uneconomical when considering sunk costs and payment of royalties. The incentive is applicable to deepwater, 200 meters and greater, and the operator must receive approval through an application process.

Citation: 30 CFR Part 203.60-91

Effective: Feb. 14, 2002

Goal: Increase development of offshore deepwater resources.

International Incentive Programs

CANADA

FEDERAL PROGRAMS

Atlantic Canada Investment Tax Credit (ACITC)

The federal government offers a tax credit specific to investments in Atlantic Canada. ACITC provides a credit equal to 10% of the cost of certain investments. Among those investments are the costs associated with bringing an offshore well into production. The ACITC is not refundable for foreign corporations, but is refundable under certain circumstances for Canadian-controlled private companies. This tax credit can be used to reduce federal income taxes in one of two ways. It can be used to offset federal income taxes otherwise payable, or it can be used to receive a full or partial refund in the year that the expenses are incurred.

Citation: Canadian Income Tax Act, Subsection 127(9)

Objective: To specifically promote economic development in the Atlantic provinces and the Gaspé region.

ALBERTA

Enhanced Oil Recovery Royalty Relief

Introduced in 1977, this program offsets the costs of enhanced oil recovery (EOR) after the less costly primary and secondary extraction methods have been exhausted. The program's goal was to facilitate the use of EOR methods for conservation of petroleum resources and to prolong the economic production life of mature oil pools. Alberta Energy shares in the costs of EOR projects by reducing the royalty payable on incremental oil production. The allowable EOR costs are incremental to the base case recovery scheme and must be approved by Alberta Energy.

The program is open to applications for new projects and expansion of existing projects. There are some temporary program features in order to encourage industry to undertake carbon dioxide EOR projects. The key criteria for EOR project approval are:

- The project must be on enhanced recovery scheme - inject hydrocarbons, carbon dioxide, nitrogen, chemicals or other approved material.
- The project is likely to produce more oil from the pool than could be produced under the base recovery scheme.
- The costs to implement and operate the project are significantly greater than the costs to implement and operate the base recovery scheme.
- A technical and economic review determines that the royalty reduction is in the public interest.

Citation: A.R. 348/93

Effective date: Jan. 1, 1977; review by Dec. 31, 2013

Goal: Encourage the use of enhanced oil recovery methods to conserve Alberta's petroleum resources.

CO₂ Projects Royalty Credit

Alberta believes that industry's ability to undertake certain projects is currently limited by related technical and financial risks. This program provides a reduction in royalties to encourage producers to undertake demonstration CO₂ projects, and is a temporary feature of Alberta's royalty system. A maximum of \$15 million will be provided over five years in the form of oil and/or natural gas royalty credits to offset up to 30% of allowed costs in approved CO₂ projects. A maximum of \$5 million in royalty credits may be approved for a single CO₂ project. Approval of applications will be constrained by total program funding, time limit for the program, and project selection criteria. As the program is not ring-fenced to production from the project site, royalty credits may be applied against the payment of petroleum or natural gas royalty owing to the Crown. The royalty credit can be claimed periodically upon commencement of CO₂ injection, without awaiting production from the project site.

Citation: A.R. 120/2003

Effective dates: Jan. 1, 2003; review by Dec. 31, 2008

Goal: To promote development of a CO₂ enhanced oil and natural gas recovery industry in Alberta.

Third Tier Exploratory Well Royalty Exemption

A third tier exploratory well is an oil well or an oil sands well that was spudded after Sept. 30, 1992, and classified as a new field wildcat (NFW), a new pool wildcat (NPW), or a deeper pool test (DPT). Wells producing from third-tier vintage oil pools receive a lower royalty rate. The lower royalty rate plus the royalty holiday is meant to reflect the higher costs of finding and developing smaller oil pools. The goal of this program is to encourage the discovery of new oil pools in a mature basin.

The program reduces royalty on the oil well that results in the discovery of a new productive pool. The royalty holiday is effective from the first production month until the accumulated royalty holiday reaches \$1 million or 12 production months, whichever occurs first. Wells that commence production on or after Oct. 1, 1992, will be reviewed by Alberta Energy to assess program eligibility. The royalty holiday will be established for qualifying wells when Alberta Energy calculates royalty for the month that initial oil production is reported. The holiday is retroactive, to the month when production commenced. No application is required for the program.

Citation: A.R. 16/1993

Effective date: Oct. 1, 1992; no sunset

Goal: To encourage the discovery of new oil reservoirs.

Reactivated Well Royalty Exemption

A reactivated well is an oil well or oil sands well that was reactivated on or after Oct. 1, 1992, after the well did not produce any substance during its qualifying period. The program was introduced by Alberta Energy in 1992 with the goal of encouraging reactivation of shut-in oil or oil sands wells.

The program provides a royalty holiday for the wells that are successfully reactivated to help earlier recovery of the reactivation costs. Non-producing wells that commence production on or after Oct. 1, 1992, will be reviewed by Alberta Energy to establish the royalty holiday for the qualifying wells. The royalty holiday is available from the reactivation date until a cumulative of 8,000 cubic meters of oil has been produced from the reactivated well. No application is required for the program.

Citation: A.R. 352/1992

Effective date: Oct. 1, 1992; no sunset

Goal: To encourage reactivation of non-producing wells.

Low Productivity Well Royalty Reduction

In 1992, Alberta Energy developed this policy to alleviate the royalty burden on low productivity oil wells. The goal of the program is to ensure that royalty is not a barrier to the incremental investments necessary to increase production from low productivity oil wells.

The program provides a maximum royalty rate of 5% of oil production for wells currently producing at modest levels. Well production history will be reviewed by Alberta Energy to establish royalty adjustment for eligible wells. The program ensures that the royalty rate applying to the first 16,000 cubic meters of oil or oil sands production from each eligible well will be the lower of 5% or the rate determined by the oil royalty formula. No application is required for the program.

Citation: A.R. 350/1992

Effective date: Oct. 1, 1992; no sunset

Goal: To encourage additional production from low productivity wells.

Horizontal Re-entry Well Royalty Reduction

This program was introduced by Alberta Energy in 1992 with the support of the petroleum industry. The goal of the program is to prolong the economic life of mature oil pools by using horizontal well technology to improve resource conservation.

The program caps the royalty rate for oil production from an eligible horizontal extension. The cap will be the royalty rate associated with the average production volume for the latest 12 months when production occurred prior to the horizontal re-entry. For wells with a 12-month production average of up to 184 cubic meters per month, royalty will be capped at one half that rate for incremental production that exceeds the qualifying average. An application must be submitted to Alberta Energy in order to obtain the capped royalty for horizontal re-entry oil well production.

Citation: A.R. 348/1992

Effective date: Oct. 1, 1992; no sunset

Goal: To encourage incremental production from mature pools.

Experimental Project Petroleum Royalty

The policy was introduced in 1979 to encourage the development of new and improved methods for crude oil recovery. The program reduces the royalty associated with experimental projects.

The experimental schemes approved by the Energy and Utilities Board are eligible for a flat royalty rate of 5% of production during the experimental royalty period. An operator must apply to Alberta Energy to request approval of the scheme in order to obtain the 5% experimental royalty rate.

Citation: A.R. 65/1992

Effective date: 1979; no sunset

Goal: To encourage development of new and improved oil recovery methods.

Innovative Energy Technologies

Alberta Energy introduced this program in June 2004, to increase environmentally sound recovery from existing reserves and encourage responsible development of new oil, natural gas and in-situ oil sands

reserves. The program offers royalty adjustments of up to \$200 million over five years to specific pilot and demonstration projects that use new or innovative technologies. The program is designed to assist industry to find commercial technical solutions to the gas over bitumen issue that will allow efficient and orderly production of both resources.

Producers wishing to participate in the program must complete an application and submit it to Alberta Energy by the application deadline. Applications must demonstrate how the proposal fits the program objectives by performing a self-assessment against specific evaluation criteria. As funding for this program is limited, project applicants will be ranked and prioritized by Alberta Energy. Applicants will receive notification of project approval decisions from Alberta Energy. The program provides royalty adjustments of up to \$10 million per project based on a maximum of 30% of eligible costs. Royalty adjustments can be applied against any oil, natural gas or oil sands royalty obligations.

Citation: A.R. 250/2004

Effective date: June 2, 2004; review by Oct. 31, 2013

Goal: Encourage development/application of new technologies to increase oil/gas/oil sands recovery.

Deep Gas Royalty Holiday

This program was initiated by Alberta Energy in 1985 in order to encourage exploration for deep gas pools. As deep wells are very expensive to drill, the program provides a reduction in royalty for wells dependent upon depth drilled.

The program applies to all new wells drilled into previously undefined gas pools or extensions of existing pools located below 2,500 meters. The royalty holiday is defined in terms of a dollar amount applied against royalties. The royalty holiday applies until the value of the natural gas and by-products exempted equals the amount determined by a depth-based schedule. The maximum value of the holiday is \$3.6 million, and the entitlements must be used within 10 years from the finished filling date. No application is required to receive a royalty reduction under the program.

Citation: A.R. 220/2002

Effective date: May 31, 1985; no sunset

Goal: To encourage the discovery of deep natural gas pools.

Otherwise Flared Solution Gas Royalty Waiver

This program was introduced by Alberta Energy in 1999 to encourage the reduction of solution gas flaring in the province. The Crown royalty is waived on uneconomic solution gas and gas by-products for those wells approved under the program. An application is required in order to receive a royalty waiver under the program.

Citation: A.R. 220/2002

Effective date: Jan. 1, 1999; no sunset

Goal: To reduce the volume of solution gas being flared in Alberta.

Low Productivity Well Allowance

This program was implemented by Alberta Energy in 1978 to encourage the production of natural gas from marginal gas wells in the province. The Crown royalty is reduced in recognition of the higher production costs for low productivity gas wells. Gas wells producing at less than $16.9 \times 10^3 \text{ m}^3/\text{day}$ are entitled to a low productivity allowance that can reduce the natural gas and ethane royalty rates to as low as 5%. Natural gas and ethane recovered from oil wells is also eligible for this allowance, if the oil production is less than $0.15 \text{ m}^3/\text{day}$ and the solution gas production is less than $16.9 \times 10^3 \text{ m}^3/\text{day}$. No

application is required to receive a royalty reduction under the program.

Citation: A.R. 220/2002

Effective date: 1978; no sunset

Goal: To encourage additional gas production from low productivity wells.

BRITISH COLUMBIA

Deep Gas Re-entry Royalty Program

For a deep re-entered well, a deep re-entry deduction amount may be deducted from a reporting entity's royalty payable if the well has a reentry date after Nov. 30, 2003. A royalty tax reduction of 23% of drilling and completion costs.

Citation: Regulation

Effective date: Nov. 30, 2003

Goal: Encourage exploration and development of deep gas sources by enhancing drilling economics.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Deep Gas Discovery Royalty Program

Deep Discovery Wells would qualify for the lesser of either a three-year royalty holiday or 283,000,000 m³ of royalty free gas. A Deep Discovery Well is a well that has a pay the top of which has a True Vertical Depth deeper than 4000m and has a rig release date after Nov. 30, 2003, and its surface location is at least 20 kilometers away from the surface location of any well in a recognized pool of the same formation.

Citation: Regulation

Effective date: Nov. 30, 2003

Goal: Encourage exploration and development of deep gas sources by enhancing drilling economics.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Deep Gas Royalty Program

It is estimated that approximately 12 tcf, or 40% of the remaining marketable natural gas in British Columbia, is deep natural gas. Deep natural gas resources are very important for future development of the natural gas sector in British Columbia. Deep natural gas drilling has higher costs and lower success rates as compared to conventional development drilling. The deep well royalty program will provide a royalty credit amounting to approximately 23% of the drilling and completion costs. The amount of royalty credit depends on drilling location and depth. A deep well-depth deduction amount may be deducted from a reporting entity's royalty payable if:

- the well in which the deep well events are located has a spud date after Nov. 30, 2003.
- the well depth deduction amount is based on the deepest productive deep well event in the well.

Citation: Regulation

Effective dates: Nov. 30

Goal: Encourage exploration and development of deep gas sources by enhancing drilling economics.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Coalbed Gas Royalty

- Includes produced water handling costs in the producer cost of service allowance to address the added water management costs;
- Creates a royalty bank to collect excess allowance to be used against future assessed coal seam natural gas royalties;
- Increase the marginal well adjustment factor threshold to 600,000 cubic feet per day from 180,000 cubic feet per day to address the lower production rates; and
- Provides a \$50,000 royalty credit for coal seam natural gas wells.

The Royalty Tax reduction is 10 - 12%.

Citation: Regulation

Effective date: March 1, 2002

Goal: Encourage coal seam natural gas development.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Marginal Gas Well Royalty Program

Qualifying marginal natural gas wells based on depth and initial production rates will have reduced royalties. The Royalty Tax reduction is 10 - 13%.

Citation: Regulation

Effective dates: July 1, 2003

Goal: The purpose of this targeted relief is to induce activity that would not otherwise happen under the predicted future economic environment utilizing the current fiscal regime.

Active supporters: Canadian Association of Petroleum Producers (CAPP), and the Ministry of Energy, Mines and Petroleum Resources

Marginal Gas Well Royalty Reduction

Natural gas wells near the end of their economic life receive reduced royalty rates to extend well production. The Royalty Tax reduction is 10 - 12%.

Citation: Regulation

Effective date: April 1, 2001

Goal: Extend marginal well production and maximize royalties.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Ultra-Marginal Gas Royalty Program

Provides a 50% royalty tax reduction. This is a royalty program targeting ultra-marginal natural gas resources.

Citation: Regulation

Goal: Promote drilling and development of tight gas resources.

Active supporters: Ministry of Energy, Mines and Petroleum Resources.

Royalty Credits for Infrastructure

Provides royalty credits of up to \$60 million annually, currently towards the construction, upgrading and maintenance of road infrastructure in support of resource exploration and development.

Citation: Regulation

Effective date: July 1, 2005

Goal: Improve access to resources, extend the drilling season, increase economic activity in British Columbia's heartlands communities and increase revenue to the province.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Summer Royalty Program

The summer royalty program provides a credit of the lesser of \$100,000 or 10 percent of drilling and completion costs for oil and natural gas wells drilled between April 1 and Nov. 30.

Citation: Regulation

Effective dates: 2003

Goal: Extend drilling season for opportunities producing/selling time for oil and gas products.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Heavy Oil Royalty

Heavy oil wells are subject to lower royalty rates reflecting the higher operating costs and lower market value. The Royalty Tax reduction is 7 - 16%.

Citation: Regulation

Effective date: Aug. 1, 1999

Goal: To enhance heavy oil resource development and maximize royalties.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Incremental Oil

Incremental oil includes oil that would not have been recovered without a new pressure maintenance scheme, an improved pressure maintenance scheme or other enhanced oil recovery scheme methods, but does not include heavy oil. Incremental oil will be considered as either new oil or third tier oil and be subjected to a lower royalty rate. The Royalty Tax reduction is 10 - 25%.

Citation: Regulation

Effective date: Aug. 1, 1999

Goal: To encourage enhanced oil recovery and maximize royalties.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

Net Profit Royalty Regime for Development of Unconventional Gas Resources

Proposing net profit royalty regime for the commercial production of unconventional resources such as shale gas, coal seam natural gas as well as enhanced gas recovery and remote area resources.

Citation: Proposed Regulation

Effective date: Proposed Regulation

Goal: To facilitate the development of unconventional gas resources in British Columbia.

Active supporters: Ministry of Energy, Mines and Petroleum Resources

NEWFOUNDLAND AND LABRADOR

Generic Onshore Royalty Regime Overview

The royalty regime is designed to be sensitive to the levels of risks and profits associated with the area in question and to be comparative with the royalty regimes in other districts, while providing an equitable sharing of revenues.

The similarity in the offshore and onshore geology, coupled with the potential for the discovery of hydrocarbon accumulations both in the onshore and nearshore areas, have led to increased interest by the petroleum industry in developing the western Newfoundland area. The establishment of a royalty regime contributes to lowering the risks to the petroleum industry as well as fully assessing the petroleum potential in this area.

This system is based on extensive economic analysis and is designed:

- to reflect the attractiveness of the province's onshore petroleum resources;
- to be sensitive to small and marginal prospects;
- to be competitive with the royalty systems applied in other jurisdictions; and
- to ensure a minimum level of fiscal benefits to Newfoundland and Labrador.

The royalty holiday provides the most assistance to small and marginal prospects, ensuring that no royalty will be paid on the first 2 million barrels, or equivalent, of production. The basic royalty ensures that beyond 2 million barrels, the province will receive a minimum of 5% of gross revenue. The profit sensitive component is designed to reflect changing economic circumstances and to ensure our competitiveness with the systems applied in other jurisdictions. Unless a certain profit level is exceeded, then no additional royalty beyond the 5% basic will be levied. If, however, such a profit level is exceeded, then government revenue will increase as project profitability increases.

The discovery of hydrocarbons in Newfoundland and Labrador has the potential to create new economic opportunities. The development of a viable petroleum industry in western Newfoundland could represent a new industry whose magnitude will be very dependent on the success of the current round of exploration programs.

Definitions

Gross revenue: gross sales revenue less transportation costs to point of sale.

Net revenue: gross revenue less uplifted costs.

Costs: exploration, capital, and operating.

Uplifts: gross-up of costs (proxy for overheads).

Return allowance: allowance for a rate of return on investment (proxy for cost of capital).

Components of Royalty Regime

The regime has three basic components that are:

1. Royalty Holiday
2 million barrels or equivalent (the 2 million-barrel holiday in the onshore was used as an incentive to attract exploration and development of onshore petroleum resources);
2. Basic Ad Valorem Royalty
5% of gross revenue;

3. Two Tier Net Profits Royalty
 - a. Incremental Royalty — Tier 1: 20% of net revenue after a rate of return of 5% plus the long-term government bond rate.
Type: Net profit based.
Term: Commences upon incremental royalty tier 1 payout and continues to the end of production.
Amount: Net revenue multiplied by the tier 1 incremental royalty rate and basic royalty is creditable against tier 1 incremental royalty.
When: Eligible costs have been repaid, including eligible capital and operating costs; basic royalty; and a tier 1 incremental royalty return allowance.
 - b. Incremental Royalty--Tier 2: 5% of net revenue after a rate of return of 15% plus the long-term government bond rate.
Type: Net profit based.
Term: Commences upon incremental royalty tier 2 payout and continues to the end of production.
Amount: Net revenue multiplied by the tier 2 incremental royalty rate.
When: Eligible costs have been repaid, including eligible capital and operating costs; basic royalty; incremental royalty — tier 1; and a tier 2 incremental royalty return allowance.

Effective: 1994

Goal: To facilitate exploration and development through fiscal framework certainty.

Generic Offshore Royalty Regime

In 1996, the province announced the establishment of a generic offshore royalty regime that applies to the development of all petroleum resources in the Newfoundland and Labrador offshore area, with the exception of the Hibernia and Terra Nova projects.

This generic offshore royalty regime will translate into increased industry activity, more employment and a stronger provincial economy. It will also provide government with a new source of revenue. The basic royalty commences at a low rate (1%) and increases as certain cumulative levels of production are reached or when costs are recovered, providing an incentive to develop small and marginal prospects by ensuring that minimal royalties are paid on these types of fields. Once cumulative production reaches 50 million barrels (mmbbls), or 20% of the initially established reserves from the project, the province will receive 2.5% of gross revenue increasing to 5% and then to 7.5% at higher levels of cumulative production. If all costs are recovered early from the project, the royalty rate will increase to 5% regardless of the cumulative production level.

Components of Royalty Regime

The regime has two basic components that are:

1. Basic Ad Valorem Royalty
 - 1 to 7.5% of gross revenue
 - a. 1% until the earliest of:
 - 20% of reserves
 - 50 million barrels of production
 - Cost recovery

- b. 2.5% until the earliest of:
 - 100 million barrels of cumulative production
 - Cost recovery
- c. 5% for the next 100 million barrels of production
- d. 7.5% thereafter

2. Two Tier Net Profit Incremental Royalty

- a. Tier 1: 20% of net revenue after a rate of return of 5% plus the long-term government bond rate.
 Type: Net profit based.
 Term: Commences upon incremental royalty tier 1 payout and continues to the end of production.
 Amount: Net revenue multiplied by the tier 1 incremental royalty rate and basic royalty is creditable against tier 1 incremental royalty.
 When: Eligible costs have been repaid, including eligible capital and operating costs; basic royalty; and a tier 1 royalty return allowance.
- b. Tier 2: 10% of net revenue after a rate of return of 15% plus the long-term government bond rate.
 Type: Net profit based.
 Term: Commences upon incremental royalty tier 2 payout and continues to the end of production.
 Amount: Net revenue multiplied by the tier 2 incremental royalty rate.
 When: Eligible costs have been repaid, including eligible capital and operating costs; basic royalty; incremental royalty — tier 1; and a tier 2 royalty return allowance.

The two tier net royalty is profit sensitive. It is designed to reflect changing economic circumstances and to ensure competitiveness with royalty systems in other jurisdictions. When a certain profit level is achieved, the net royalty is applied with the province receiving the greater of the gross or tier one net royalty payable. If profits increase beyond that level, government revenue will also increase. If these profits increase significantly, then government revenue will also increase as the tier two net royalty component will levy an additional 10% of net revenue.

Citation: Newfoundland and Labrador Regulation July 1, 2003

Effective: 1996

Goal: To promote exploration and development while ensuring that the province receives a fair share of offshore petroleum revenues.

Petroleum Exploration Enhancement Program (PEEP)

- \$5 million
- 2 years
- \$2 million allocated this fiscal year

Effective date: June 6, 2007

Goal: Exploration enhancement program to assist companies in obtaining crucial geoscientific information in exchange for an equity position in future projects.

Active supporters: Government of Newfoundland & Labrador, Newfoundland and Labrador Hydro, and industry

NOVA SCOTIA

Research and Development Tax Credit

The province of Nova Scotia offers a research and development tax credit, which is similar to the federal Scientific Research and Experimental Development incentive program. Nova Scotia taxpayers, who engage in qualified research, are eligible for this incentive.

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Oil & Gas Conservation Commission

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WEST VIRGINIA

James Martin, Chief, Office of Oil and Gas
Division of Environmental Protection

WYOMING

Don Likwartz, State Oil & Gas Supervisor
Oil and Gas Conservation Commission

Definitions

Abandoned wells are wells which have been permanently plugged. The remaining petroleum production potential of these wells is often lost forever.

Bcf is an acronym for “billion cubic feet” of gas.

BOPD is an acronym for “barrels of oil per day.”

Development wells are new wells drilled into existing reservoirs and are also known as “in-fill” wells.

Discovery wells are wells drilled to extract petroleum from a previously unproduced pool.

Enhanced oil recovery usually refers to the employment of tertiary recovery and secondary recovery methods. These higher technology, more expensive techniques include miscible fluid displacement, microemulsion flooding, thermal methods, and other chemical flooding methods.

Idle wells are oil or gas wells which have not been abandoned, but are not currently producing. Idle wells are also referred to as “inactive” or “shut-in” wells.

Incremental production is the increase in the amount of oil or gas produced as a direct result of an enhanced recovery or enhanced production project.

Mcf is an acronym for “thousand cubic feet.”

Marginal wells are low-producing wells on the margin of profitability. States differ in the maximum a well can produce and qualify as a marginal well.

Orphan wells are idle wells whose owners are unknown, cannot be located, or are insolvent.

Primary recovery of oil is powered by the pressure energy existing in the reservoir. Further production requires the artificial introduction of energy.

Recompletion is a downhole operation in an existing well which initiates production in a geologic interval not currently producing in that well.

Secondary recovery generally consists of the injection of water in a controlled fashion into a known reservoir in order to displace the oil from the rock and push it to a producing well.

Severance tax is an excise tax levied on a barrel of oil or cubic foot of gas produced within a state. It is also called “production tax.” Severance taxes are of two types: *ad valorem*, which is a percentage of the value of the product; and *specific* per barrel/Mcf, which is based on units of production (*i.e.*, \$1/barrel).

Stripper wells are low-volume wells in the final stages of production. Exact definitions, as used in state incentive programs, vary from state to state. Since production from these wells is quite low, they are also marginal wells.

Tertiary recovery involves steam flooding or the injection of carbon dioxide gas to manipulate the reservoir and improve recovery.

Workovers are well-servicing operations designed to maintain, restore or increase the productivity of an oil or gas well and extend the well’s economic life. Workovers can include such operations as repairing the cement casing in the well hole, re-acidizing, re-perforating, and removing accumulated sand or paraffin from the wellbore. These are standard operations that are not considered to be enhanced recovery projects.

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For more information about the IOGCC or to order additional copies of this report, visit www.iogcc.state.ok.us or call 405.525.3556. For additional information about the Energy Council, call 972.243.7788.

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APPENDIX

C

2007

**Summary of State Statutes
and Regulations
for Oil and Gas Production**

INTERSTATE OIL AND GAS COMPACT COMMISSION

**SUMMARY OF STATE STATUTES AND REGULATIONS
FOR OIL AND GAS PRODUCTION**

2007

THIS UPDATE REPLACES ALL PAGES PREVIOUSLY INSERTED.

PLEASE RETAIN THE STATE DIVIDERS FOR FUTURE USE

ALABAMA

Administration

1. State agency: State Oil and Gas Board, 420 Hackberry Lane, P.O. Box 869999, Tuscaloosa, AL 35486-6999. Phone (205) 349-2852; Fax (205) 349-2861. Our URL is <http://www.ogb.state.al.us>. Staff e-mail addresses are: *@ogb.state.al.us (*Insert staff person's first initial and last name or insert "info" for general information).
2. Docketing procedure: Regular Board hearings are generally held every 4 to 6 weeks. For a hearing schedule check our Web site. Meetings are held in the Board Room of the State Oil and Gas Board building located on the campus of the University of Alabama in Tuscaloosa, unless otherwise specified in the Board's Notice of Meeting. The petitioner shall file a proposed notice for publication with the Board accompanied by a written request for approval to publish the notice for hearing on a specific scheduled hearing date of the Board not less than twenty three (23) days prior to the meeting at which the petition shall be heard. The Supervisor will review the notice and provide petitioner an approved notice for publication including the newspaper(s) in which the notice should be published. Petitioner shall publish the notice in the newspaper at least 10 days prior to the hearing. When a petition pertains to specific land, notice of such petition shall be published once in the newspaper with the largest circulation in the county or counties where the affected land lies. When a petition pertains to a matter or statewide application, notice of such petition shall be published in the newspaper with the largest circulation in Jefferson and Mobile Counties. Upon filing a notice petitioner shall submit a \$150 filing fee. Five copies of all exhibits to be presented as evidence must be submitted to the Board at least 14 days prior to the hearing. Affidavits and petitions must be filed at least 14 days prior to the hearing. One filing fee may be submitted for all notices filed by the same petitioner that relate to the same subject matter.
 - (a) Emergency orders: Emergency action may be taken by the Board without a public hearing. The emergency order will remain in force until relief is granted after notice and hearing, except that such emergency order will not remain in force longer than 45 days.
 - (b) Notice: Additionally, the petitioner must give notice by first class mail when the petition involves an exceptional location, establishing a drilling or production unit, amending or reforming an established drilling or production unit, establishing or amending allowables, force pooling, or compulsory unitization, or when the Board determines that notice to certain parties is necessary because of the particular petition filed. The notice of the hearing is posted on the Web site of the Office of the Alabama Secretary of State.

Bond

1. Compliance bond required: Rule 400-1-2-.03 (onshore), Rule 400-2-2-.03 (offshore), 400-3-2-.03 (coalbed), and 400-6-3-.01 (underground storage facility for a solution-mined cavity and storage well).
2. Conditions of bond: Compliance with the Rules and Regulations, proper plugging, and restoration of location.
 - (a) Amount per well:

<u>Onshore</u>	<u>Depth (ft.)</u>	<u>Amount</u>	<u>Depth (ft.)</u>	<u>Amount</u>
&	0 - 5,000	\$ 5,000	15,001-20,000	\$30,000
<u>Coalbed-</u>	5,001 -10,000	\$10,000	Greater than 20,000	\$50,000
	10,001 -15,000	\$15,000		
<u>Offshore -</u>	<u>Depth (ft.)</u>	<u>Amount</u>		
	0 - 6,000	\$100,000		
	Greater than 6,000	\$500,000		

There is a \$100,000 bond for an underground storage facility for a solution-mined cavity and storage well.

- (b) Amount of blanket bond: Onshore & Coalbed - \$100,000.
Offshore - \$1,000,000.

- (c) The Board after notice and hearing may require a different amount of bond.

Spacing

1. Spacing requirements: Rule 400-1-2-.02 (onshore); Rule 400-2-2-.02 (offshore) Rule 400-3-2-.02 (coalbed methane).

- (a) Density:

Onshore

<u>Oil wells-</u>	40-acre units 160-acre units (Supervisor may require written justification)
<u>Gas wells-</u>	40-acre units. 160-acre units (Supervisor may require written justification) 320-acre units (Fayette, Lamar, Pickens and Tuscaloosa Counties only) 640-acre units (Baldwin, Mobile, Escambia and Washington Counties only) (Supervisor may require written justification)

All well units shall consist of governmental sections or divisions; however, upon receipt of written justification units consisting of 40, 160, 320, and 640 contiguous acres other than a governmental section or division may be approved by the Supervisor or may be referred to the Board for notice and hearing.

Offshore (for offshore wells in an offshore tract)

<u>Deeper than 6,000 feet-</u>	Entire offshore tract, $\frac{3}{4}$ tract, or $\frac{1}{2}$ tract (where operator owns or controls 100% of working interest in entire offshore tract)
<u>Deeper than 6,000 feet-</u>	Up to 1,400 acres (<u>irregular offshore tracts</u>)
<u>6,000 feet or shallower-</u>	$\frac{1}{2}$ offshore tract or $\frac{1}{4}$ tract (where operator owns or controls 100% of working interest in entire offshore tract)
<u>6,000 feet or shallower-</u>	Quarter Quarter tract for regular tract and up to 360 acres for irregular tracts
<u>For offshore wells not in an offshore tract-</u>	40-acre units 160-acre units (Supervisor may require written justification) 640-acre units (Baldwin and Mobile Counties, only) (Supervisor may require written justification)

All well units shall consist of governmental sections or divisions; however, upon receipt of written justification units consisting of 40, 160, and 640 contiguous acres other than a governmental section or division may be approved by the Supervisor or may be referred to the Board for notice and hearing.

Coalbed gas- 40 acres

- (b) Lineal:

Onshore- & Coalbed
40 acre units - 330 feet from every exterior boundary
160 and 320 acre units - 660 feet from every exterior boundary
640 acre units - 1,320 feet from every exterior boundary

Offshore
Wells deeper than 6,000 feet – 1,320 feet from every exterior boundary and 500 feet from the State/Federal boundary

Wells shallower than 6,000 feet – 660 feet from every exterior boundary and 500 feet

from the State/Federal boundary

2. Exceptions: Rule 400-1-2-.02 (2) (g) (onshore), 400-2-2-.02(4) (offshore), 400-3-2-.02(2) (d) coalbed.
 - (a) Basis: If the well would be nonproductive or if topographical or other conditions make the drilling in compliance with the spacing requirements unduly burdensome. See Section 9-17-12(c) of the Code of Alabama (1975).
 - (b) Approval: After notice and hearing.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: No.
 - (c) Recompletion: No, unless well has been plugged and abandoned.
 - (d) Plugging and abandoning: No.
2. Permit fee:
 - (a) Drilling: \$300 (for a coalbed methane gas well an operator must file an additional \$150 to be deposited in the Alabama Coalbed Methane Gas Well Plugging Fund).
 - (b) Seismic drilling: No.
 - (c) Recompletion: No, unless well has been plugged and abandoned.
 - (d) Plugging and abandoning: No.
3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Rule 400-1-4-.04 (onshore), 400-2-4-.04 (offshore), and Rule 400-3-4-.04 (coalbed).
 - (a) When is directional survey necessary?

Onshore-

(1) when a well is directionally drilled, (2) when a well is drilled to a measured depth of 6,000 feet or greater, (3) when a well is expected to penetrate pore pressure gradients greater than 67 psi per hundred feet in depth, (4) when a well is expected to penetrate intervals containing hydrogen sulfide, and (5) when a well is an exceptional location and a directional survey is ordered by the Board.

Offshore-

All wells.

Coalbed-

(1) When a well is directionally drilled and (2) when a well is an exceptional location and a directional survey is ordered by the Board.

- (b) Filing of survey required? Yes, one copy filed by the operator with the Supervisor within 30 days after completion of the well.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Varies depending on proposed total depth. See Rule 400-1-4-.09 (onshore), Rule 400-2-4-.09 (offshore), and Rule 400-1-4-.09 (coalbed).
 - (b) Production casing: Sufficient depth to adequately protect the oil and/or gas bearing stratum.
2. Minimum amount of cement required:
 - (a) Surface casing: Circulate to surface.
 - (b) Production casing: At least 500 feet above the top of the producing interval for an onshore or offshore well. For a coalbed methane gas well, at least 200 feet above the top of the producing interval.
 - (c) Setting time:

<u>Onshore-</u>	12 hours for surface, intermediate or protective, and production casing.
<u>Offshore-</u>	8 hours for conductor casing and 12 hours for all other strings of casing.
<u>Coalbed-</u>	12 hours for surface and production casing.
3. Tubing requirements:
 - (a) Oil wells:

Onshore & Offshore- All flowing wells must be produced through tubing anchored by a packer and equipped with a master valve and adequate chokes or beans to properly control the flow.

Coalbed- None.
 - (b) Gas wells: Same as (a) above.

Completion

1. Completion report required: Yes. For Onshore see Rules 400-1-4-.03, 400-1-4-.08, 400-1-4-.15, and 400-1-5-.03. For Offshore see Rules 400-2-4-.03, 400-2-4-.08, 400-2-4-.12, and 400-2-5-.03. For Coalbed see Rules 400-3-4-.03, 400-3-4-.08, 400-3-4-.15, 400-3-5-.05. Reports are submitted on Forms OGB-6, OGB-7, OGB-8, OGB-9, and OGB-11.
 - (a) Time limit: File within thirty days except for Form OGB 9 related to well test which is fifteen days.
 - (b) Where submitted: To the State Oil and Gas Board, 420 Hackberry Lane, P.O. Box 869999, Tuscaloosa, AL 35486-6999.
2. Well logs required to be filed: One copy of all logs.
 - (a) Time limit: Within 30 days after completion of the well.
 - (b) Where submitted: Same as (b) in question 1 above.
 - (c) Confidential time period: Six months from completion of well.

- (d) Available for public use: All logs are available for public use after the six months confidential period, if such logs were requested to be held confidential; otherwise, available immediately.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Rule 400-1-6-.05 (onshore) and Rule 400-2-6-.05 (offshore). None for Coalbed.
 - (a) Approval obtained: For Onshore and Offshore Supervisor approval required. For Coalbed no approval required.
 4. Commingling in well bore: Rule 400-1-6-.02 (onshore), 400-2-6-.02 (offshore), 400-3-6-.04 (coalbed).
 - (a) Approval obtained: For Onshore and Offshore approval of the Board after notice and hearing. No approval required for Coalbed.

Oil Production

1. Definition of an oil well: Oil well shall mean a well capable of producing oil from an oil pool or oil pools.
2. Potential tests required: Yes, Rule 400-1-5-.03 (Onshore), 400-2-5-.03 (Offshore), and 400-3-5-.05 (Coalbed).
 - (a) Time interval: Verbal report to the Supervisor immediately, written report on Form OGB-9 within 15 days after completion of the test.
 - (b) Witness required: At the discretion of the Supervisor.
3. Statewide allowable: No.
 - (a) Pool allowable: Yes, the allowable for each pool or field is established after notice and hearing and is specified in special field rules for each field.
 - (b) Well allowable: Until special field rules are established allowables are determined pursuant to Rule 400-1-5-.04 (Onshore) and 400-2-5-.05 (Offshore).
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: Yes.
 - (a) Provision for limiting gas-oil ratio: Rule 400-1-5-.08 (Onshore), Rule 400-2-5-.08 (Offshore), maximum gas limit of 2,000 cubic feet per barrel of oil allowable determined by the allocation formula.
 - (b) Exception to limiting gas-oil ratio: Subject to Board action after notice and hearing.
5. Bottom-hole pressure test reports required: Yes, initially pursuant to Rule 400-1-6-.03 (Onshore) and 400-2-6-.03 (Offshore). Special field rules contain provisions for submission of subsequent bottom-hole pressure tests.
 - (a) Periodical bottom-hole pressure surveys: As specified in special field rules.
6. Commingling oil in common facilities: The Board will consider commingling of production after notice and hearing.
7. Measurement involving meters: For Onshore Rule 400-1-5-.05 and 400-1-5-.06 and for Offshore Rule 400-2-5-.05 and 400-2-5-.06. In addition, certain special field rules contain rules pertaining to metering of production.
8. Production reports:
 - (a) By lease: No.

- (b) By well: Monthly production reports.
- (c) Time limit: By the 28th of the month following the month for which the production report covers.

Gas Production

1. Definition of a gas well: Gas well shall mean a well capable of producing gas from a gas pool or gas pools.
2. Pressure base 14.65 psia @ 60 degrees F.
3. Initial potential tests: Yes, Rule 400-1-5-.03 (Onshore), 400-2-5-.03 (Offshore), and 400-3-5-.05 (Coalbed).
 - (a) Time interval: Verbal report to the Supervisor immediately, written report on Form OGB-9 within 15 days after completion of the test. For initial capacity test, unless exempted by special field rules, multi-point back pressure test with results reported on Form OGB-10 within 15 days after a test has been completed. For annual capacity tests, unless otherwise exempted by special field rules, one-point back pressure with results reported on Form OGB-10A within 15 days after a test has been completed.
 - (b) Witness required: At the discretion of the supervisor.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes, for Onshore and Offshore the allowable for each pool or field is established after notice and hearing and is specified in special field rules for each field. For Coalbed, none.
 - (b) Well allowable: Until special field rules are established allowables are determined pursuant to Rule 400-1-5-.04 (Onshore) and 400-2-5-.05 (Offshore). For (Coalbed) the gas allowable is 100% of the wells capacity to produce pursuant to Rule 400-3-5-.06.
 - (c) Exempt allowable: No, except for (Coalbed) the gas allowable is 100% of the wells capacity to produce pursuant to Rule 400-3-5-.06.
5. Bottom-hole pressure test reports required: Yes, initially pursuant to Rule 400-1-6-.03 (Onshore) and 400-2-6-.03 (Offshore). Special field rules contain provisions for submission of subsequent bottom-hole pressure tests.
 - (a) Periodical bottom-hole pressure surveys: As required by special field rules.
6. Commingling of gas in common facilities: The Board will consider commingling of production after notice and hearing.
7. Measurement involving meters: For Onshore Rule 400-1-5-.07, for Offshore Rule 400-2-5-.07, and for Coalbed Rule 400-3-5-.07. In addition, certain special field rules contain rules pertaining to metering of production.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Monthly production reports.
 - (c) Time limits: By the 28th day of the month following the month for which the production report covers.

Underground Injection

1. State agencies that control the underground injection of fluids: The State Oil and Gas Board regulates all Class II injection operations in Alabama in accordance with Rule 400-4-1-.01 et seq. All other types of underground injection operations are regulated by the Alabama Department of Environmental Management.

Unitization

1. Compulsory unitization of all or part of a pool or common sources of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 66 2/3%.
 - (b) Royalty interest: 66 2/3%.

Taxation

Gas severance tax = 10.0% (2.0% production tax and 8.0% privilege tax)

Gas ad valorem tax = 0.0%

Total gas tax burden = 10.0%

Oil severance tax = 10.0% (2.0% production tax and 8.0% privilege tax)

Oil ad valorem tax = 0.0%

Total oil tax burden = 10.0%

1. Tax collecting agency: The severance tax laws are administered by the Severance Tax Section, Sales, Use & Business Tax Division of the Alabama Department of Revenue, 202 Administrative Building, Montgomery, AL 36130.
2. How tax is computed: The current tax rate of 10 percent (8 percent privilege and 2 percent production) was enacted in 1979 with the passage of Act No. 79-434. Both privilege and production taxes are computed on the gross value of hydrocarbons at the point of production. Since 1979, numerous exceptions have been granted to the 8 percent privilege tax rate. The reductions were enacted by Acts 80-708, 83-39, 83-889, 84-328, 84-660, 84-661, 84-672, 85-911, 88-601, 96-877. The Privilege Tax is set forth in the *Code of Alabama* (1975) under Title 40, Chapter 20, and the Production Tax is codified as Title 9, Chapter 17, Sections 25 through 31. The current severance tax rates and exemptions are listed below.
3. Exemptions or exceptions:
 - (a) Incremental oil or gas production from an approved enhanced recovery project on or after January 1, 1985, will be taxed at a rate of 6% (a 4% privilege tax and 2% production tax) of the gross value of said incremental oil or gas production. The State Oil and Gas Board of Alabama shall approve the qualified enhanced recovery project and the determination of the projected oil or gas production that could have otherwise been produced without the benefit of the initiation of said qualified enhanced recovery project at a hearing held pursuant to Section 9-17-7 of the *Code of Alabama* (1975), as amended, and shall notify the Alabama Department of Revenue thereof.
 - (b) All wells producing 200,000 cubic feet or less of gas per day or 25 barrels or less of oil per day will be taxed at a rate of 6% (a 4% privilege tax and 2% production tax).
 - (c) All oil and gas produced from onshore discovery wells, all oil and gas produced from onshore development wells on which drilling commenced within four (4) years of the completion date of the discovery well and producing from a depth of 6,000 feet or greater, and oil and gas produced from onshore development wells on which drilling commenced within two (2) years of the completion date of the discovery well and producing from a depth less than 6,000 feet will be taxed at a rate of 8 % (a 6 % privilege tax and 2 % production tax) of the gross value of said oil and gas at the point of production for a period of five (5) years from the date production begins from said discovery and development wells, provided, that all production to receive an 8% tax rate, which is produced from discovery wells, must be from discovery wells permitted by the State Oil and Gas Board after July 1, 1984, and that all production to receive an 8% tax rate from development wells on which drilling commenced within the required time of completion of a discovery well, which was permitted after July 1, 1984, and said development well must also have been permitted after July 1, 1984. Also, the 8% severance tax rate applicable to a discovery well or development well will be applicable to any replacement well drilled to replace the discovery well or the development well during the 8%, 5-year tax rate period for only the remainder of the said tax rate period.

- (d) All oil and gas produced by offshore production at depths greater than 18,000 feet below mean sea level will be taxed at a rate of 8% (a 6% privilege tax and 2% production tax).
 - (e) Any well which begins commercial production of occluded natural gas from coal seams after June 7, 1984, will be taxed at a rate of 4% (a 2% privilege tax and 2% production tax) of the gross value of said occluded natural gas at the point of production for a period of five years after such well begins production. (Expired June 7, 1994)
 - (f) For any well which the initial permit was issued by the State Oil and Gas Board after July 1, 1988, except a replacement well for a well for which the initial permit issued by the State Oil and Gas Board is dated before July 1, 1988, the rates for all onshore wells, unless otherwise exempted, and offshore wells greater than 18,000 feet in depth shall be taxed at a rate of 2% lower than the rate otherwise indicated (onshore: a 6% privilege tax and 2% production tax; offshore: a 4% privilege tax and 2% production tax).
 - (g) Natural gas injected for cycling, repressuring, pressure maintenance, lifting of oil, or vented or flared in connection with the production of oil shall be exempt from the 2% production tax and the 8% privilege tax. However, if any gas so injected is sold, then the gas shall not be exempt from the production or privilege tax.
 - (h) Any well for the initial permit issued by the Oil and Gas Board is dated on or after July 1, 1996, and before July 1, 2002, the applicable rate shall be reduced by 50 percent for a period of five years commencing with commercial production.
 - (i) All oil and gas produced, all leases in production, and all oil and gas under the ground on producing properties within the State of Alabama is exempt from all ad valorem taxes now levied or hereafter levied by the State of Alabama, or by any county or municipality. No additional assessment is added to the surface value of such lands by the presence of oil or gas thereunder or its production therefrom.
4. Name of tax: Severance.
 5. Statutory citation: Production Tax - Section 9-17-25 Code of Alabama (1975); Privilege Tax - Section 40-20-2 Code of Alabama (1975); Exemption from ad valorem tax - Section 40-20-12 Code of Alabama (1975).

Land Leasing Information

1. Leasing Method: Sealed competitive bids.
2. Notice Method: Advertisement-Montgomery Advertiser and in a newspaper in the county in which the land is located - at least 25 days before the final date for submitting bids.
3. Minimum bidding \$ (per acre): The minimum bid per acre depends on several criteria with no set formula. Within the past few years - No less than \$125.
4. Qualification of the bidder: No pre-qualifying of bidders.
5. State Statues: AL ST
 §9-17-60
 §9-17-65
 §9-17-66
 §9-17-67
6. Maximum acres: One tract, 5,165 acres.
7. Contact: Jim Griggs
 Alabama Department of Conservation and Natural Resources
 Phone: (334) 242-3484
 Fax: (334) 242-0999
 E-mail: jgriggs@dcnr.state.al.us

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: State Board of Health, Department of Public Health, P.O. Box 303017, Montgomery, AL 36130-3017. Phone: (334) 206-5391, Fax: (334) 206-5387.
2. Relevant Statute/Regulations: Alabama Rules for Control of Radiation, 420-3-26.
3. Scope: These rules apply to all persons who receive, possess, use, transfer, own or acquire any source of radiation.
4. Licensing: No person shall receive, possess, use, transfer, own, or acquire radioactive material except as authorized in a specific or general license or provided otherwise - 420-3-26-.02 (2).
5. Cleaning Equipment: Cleaning equipment that is contaminated is a licensed activity subject to requirements of Rules 420-3-26-.02, 420-3-26-.03, and 420-3-26-.10.
6. Disposal of Waste: Rules for disposal of radioactive waste are listed in Rule 420-3-26-.03.
7. Subsequent Use of Equipment: Contaminated equipment is restricted in use to controlled activities.
8. Subsequent Use of Materials: Depending upon levels of contamination; unrestricted use to transfer only to someone licensed to receive said materials.
9. Release/Sale of NORM-Contaminated Land: 5 pCi/gm or less without restrictions; use otherwise restricted.
10. Projected Volume of stored NORM in the State: No estimate available.
11. Respondent: Kirksey Whatley

ALASKA

Administration

1. State agency: Alaska Oil and Gas Conservation Commission, 333 W. 7th Ave., Anchorage, AK 99501. Phone (907) 279-1433. Fax: (907) 276-7542.
2. Docketing procedure and notice: On its own motion, or upon the petition of an interested person, the Commission will fix a date for the hearing and publish notice in an appropriate newspaper. The notice will provide the essential details of the matter and set out the place for the public hearing, the date, and the time for the public hearing. The Commission will set a hearing date that is at least 30 days after the date of publication.

For an order affecting a single well or a single field, the Commission will publish notice in an appropriate newspaper that:

- sets out the essential details of the requested order,
- provides an opportunity for public comment,
- tentatively specifies a place, time, and date for a public hearing, and
- provides a telephone number that the public may use to learn if the commission will hold the tentative hearing.

A person may submit a written protest or written comments during that 30-day period. In addition, a person may request that the tentatively scheduled hearing be held by filing a written request with the Commission within 15 days after the publication date of the notice. If the Commission receives a timely request for hearing, or if the Commission desires to hold a hearing, the Commission will hold a hearing on the date and time specified in the notice. If a request for hearing is not timely filed, the Commission will, in its discretion, issue an order without a hearing.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: The bond must be; 1) a surety bond by an insurer authorized to do business in Alaska, 2) a personal bond of the operator accompanied by either a certificate of deposit or an irrevocable letter of credit issued in sole favor of the Alaska Oil and Gas Conservation Commission from a bank authorized to do business in Alaska. A personal bond may also be accompanied by other forms of security the commission determines to be adequate to ensure payment. The bond must remain in effect until the abandonment of all wells covered by the bond and final clearance of well sites are approved by the Commission.
 - (a) Amount per well: Not less than \$100,000, unless the operator demonstrates to the commission's satisfaction in the application for a Permit to Drill that the cost of abandonment and location clearance is less than \$100,000. The bond amount will then be adjusted to the cost of abandonment and location clearance.
 - (b) Amount of blanket bond: Not less than \$200,000.

Spacing

1. Spacing requirements: Yes, in the absence of an order by the Commission establishing drilling units or prescribing a spacing pattern for a pool, the following statewide spacing requirements apply:
 - (a) Density: Governmental quarter section for an oil well; governmental section for a gas well.
 - (b) Lineal: An oil well may be open to test or regular production within 500 feet of a property line only if the owner is the same and the landowner is the same on both sides of the line, 1,000' minimum separation from any well drilling to, or capable of producing from, the same pool.

A gas well may be open to test or regular production within 1,500 feet of a property line only if the owner is the same and the landowner is the same on both sides of the line; 3,000' minimum separation from any well drilling

to, or capable of producing from, the same pool.

2. Exceptions: Yes.
 - (a) Basis: Prevention of waste and protection of the correlative rights of lessees in a pool based on operating and technical data.
 - (b) Approval: Applicant must file for exception. The Alaska Oil and Gas Conservation Commission must publish notice and hold a hearing if protest is received.

Pooling

1. Authority to establish voluntarily: Yes. Owners of oil and/or gas properties may voluntarily pool their separate interests to form a drilling unit.
2. Authority to establish compulsory: Yes, discretionary. If one or more persons owning oil and gas rights fail to voluntarily pool their interests, the Commission upon petition or its own motion and after notice and public hearing will, in its discretion, issue an order pooling the owners' interest for the development of their land as a drilling unit.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes, before drilling, redrilling, re-entering or deepening of exploratory, development, service or stratigraphic test wells, or re-entering abandoned wells.
 - (b) Seismic drilling: No. However, a Miscellaneous Land Use Permit is required from the Department of Natural Resources, Division of Oil and Gas.
 - (c) Recompletion: Yes, if recompletion requires a drilling operation or re-entry of an abandoned portion of a wellbore. Other recompletion operations including re-entry of a suspended well require sundry approval.
 - (d) Plugging and abandoning: Yes, by Sundry Approval.
2. Permit fee:
 - (a) Drilling: \$100.
 - (b) Seismic drilling: N/A.
 - (c) Recompletion: \$100, if drilled deeper or to new bottom hole location.
 - (d) Plugging and abandoning: No.
3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? When any portion of the well path is less than 500 feet of a property line where ownership is not identical on both sides of the line, or when any portion of the well path is less than 200 feet from any other vertical or deviated well. The survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface. When a well is intentionally deviated and the above conditions do not apply, the well must be directionally surveyed at intervals not more than 500 feet apart on straight or tangent

sections and at intervals not exceeding 100 feet in portions of the hole where intentional angle changes are performed.

- (b) Filing of survey required: Yes.

Casing and Tubing

1. Minimum amount required depends upon stratigraphic or performance criteria.
 - (a) Surface casing: Required. Surface casing must be set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption and at a depth sufficient to provide a competent anchor for blow out prevention equipment.
 - (b) Production casing: Required. Production casing must be set and cemented through, into, or just above the production interval. If the production string is a liner, a minimum of 100 feet overlap is required.
2. Minimum amount of cement required:
 - (a) Surface casing: Fill annular space to the surface.
 - (b) Production casing: Fill annular space from the casing shoe to a minimum of 500 feet above the shoe, overpressured zones or significant hydrocarbon zones, whichever is higher. If the production string is a liner, the interval of overlap must be made pressure competent unless otherwise specifically approved, such as an open hole completion. All freshwater sands encountered below the shoe of the surface casing must be cemented in a manner that will ensure no movement of fluids into sources of freshwater.
 - (c) Setting time: No specific regulation.
3. Tubing requirements:
 - (a) Oil wells: Yes. Waivers with justification.
 - (b) Gas wells: Yes. Waivers with justification.

Completion

1. Completion report required: Yes.
 - (a) Time limit: Thirty (30) days after well completion, suspension or abandonment.
 - (b) Where submitted: Alaska Oil and Gas Conservation Commission, 333 W. 7th Ave., Anchorage, AK 99501-3192.
2. Well logs required to be filed: Yes.
 - (a) Time limit: Thirty (30) days after well completion, suspension or abandonment.
 - (b) Where submitted: Alaska Oil and Gas Conservation Commission, 333 W. 7th Ave., Anchorage, AK 99501-3192.
 - (c) Confidential time period: Yes, twenty-four (24) months following the 30-day filing period.
 - (d) Available for public use: Yes, after confidential time period has elapsed.
 - (e) Log catalog available: Yes.
3. Multiple completion regulation: Yes.
 - (a) Approval obtained: From Alaska Oil and Gas Conservation Commission upon submittal of evidence of complete

separation of flowstreams from separate pools.

4. Commingling in well bore: Yes.
 - (a) Approval obtained: From Alaska Oil and Gas Conservation Commission following application and opportunity for public hearing.

Oil Production

1. Definition of an oil well: "Oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool-by-pool basis the Commission establishes another ratio.
2. Potential tests required: No. Operator shall obtain fluid samples from each new pool at the time of discovery or before regular production and determine crude composition assay, pressure, volume and temperature properties of the crude oil, and solution or non-associated gas composition assay. Sampling and determinations must be conducted and reported in accordance with accepted industry practice. Reports must be submitted to the Commission within 45 days following completion of determinations.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
3. Statewide allowable: No.
 - (a) Pool allowable: Yes, for rate-sensitive reservoirs.
 - (b) Well allowable: If appropriate for rate-sensitive reservoirs.
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: Two times the original solution gas-oil ratio.
 - (a) Provision for lifting gas-oil ratio: An oil well may not be allowed to produce with a gas-oil ratio in excess of two times the original solution gas-oil ratio.
 - (b) Exception to limiting gas-oil ratio: Upon application to the Commission, the above limitation may be waived for approved additional recovery projects, re-injection of produced gas, or an acquisition of pool performance data needed to optimize reservoir management. Other conditions require hearing.
5. Bottom-hole pressure test reports required: Yes, on discovery wells, before significant production.
 - (a) Periodical bottom-hole pressure surveys: Yes, as designated by pool rules.
6. Commingling oil in common facilities: Yes, if individual well production is accurately determined monthly from each well.
7. Measurement involving meters: Yes, per API and Manual of Petroleum Measurement Standards.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Monthly production reports must be submitted to the Alaska Oil and Gas Conservation Commission indicating the oil, gas and water production from each well.

- (c) Time limit: Monthly.
- 9. Gas Disposition at Production Facilities: Monthly gas disposition reports for each production facility must be submitted to the Alaska Oil and Gas Conservation Commission indicating the volumes of gas which were (1) sold, (2) reinjected, (3) flared or vented for less than 1 hour, (4) flared or vented for more than 1 hour, (5) pilot or purge, (6) used for lease operations, (7) NGL gas equivalent produced, (8) purchased, (9) transferred, or (10) used for other purposes.

Gas Production

- 1. Definition of a gas well: "Gas well" means a well that produces predominantly gas at a gas-oil ratio over 100,000 scf/stb, unless on a pool-by-pool basis the commission establishes another ratio.
- 2. Pressure base 14.65 psia @ 60 degrees F.
- 3. Initial potential tests: Yes, multi-point back pressure test.
 - (a) Time interval: Before significant production begins.
 - (b) Witness required: By Commission option.
- 4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
- 5. Bottom-hole pressure test reports required: Yes, on discovery wells, before significant production.
 - (a) Periodical bottom-hole pressure surveys: Yes, by field rules.
- 6. Commingling of gas in common facilities: Yes, if the production from each well is accurately determined at least once each month.
- 7. Measurement involving meters: Yes.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Monthly production reports must be submitted to the Alaska Oil and Gas Conservation Commission indicating the oil, gas and water production from each well.
 - (c) Time limit: Monthly.
- 9. Gas Disposition at Production Facilities: Monthly gas disposition reports for each production facility must be submitted to the Alaska Oil and Gas Conservation Commission indicating the volumes of gas which were (1) sold, (2) reinjected, (3) flared or vented, for less than 1 hour (4) flared or vented for more than 1 hour, (5) pilot or purge, (6) used for lease operations, (7) NGL gas equivalent produced, (8) purchased, (9) transferred, or (10) used for other purposes.

Gas Detection

- 1. Drilling and work over rigs must meet the following minimum requirements for methane and hydrogen sulfide gas detection:

- a. the methane detection system must have a minimum of three sensing points; one sensing point must be under the substructure near the cellar, one must be over the shale shaker, and one must be above the drill rig floor near the driller's station or above the drilling platform; if the mud pits are remote from the shale shaker and enclosed, a fourth sensor must be located over the mud pits;
 - b. methane sensors must be placed to detect a "lighter-than-air" gas;
 - c. the hydrogen sulfide detection system must have a minimum of three sensing points; one sensing point must be under the substructure near the cellar, one must be near the shale shaker, and one must be above the drill rig floor near the driller's station or above the drilling platform; the commission will require additional sensors as the commission considers necessary for safety, such as at the entrance to living quarters if they are adjacent to the drill rig, or over the mud pits if they are remote from the shaker and enclosed;
 - d. hydrogen sulfide sensors must be placed to detect a "heavier-than-air" gas;
 - e. sensors must be automatic, acting independently and in parallel, and with one-minute minimum sampling intervals;
 - f. each detection system must include separate and distinct visual and audible alarms; the visual alarm must signal the low level gas alarm and the audible alarm the high level gas alarm; an audible alarm may have an "acknowledge" button;
 - g. the methane low level gas alarm must be set at not over 20 percent LEL; the high level alarm must be set at not over 40 percent LEL;
 - h. the hydrogen sulfide low level gas alarm must be set at 10 ppm; the high level alarm must be set at not over 20 ppm;
 - i. each alarm must be automatic and must be visible and audible from the driller's or operator's station; the hydrogen sulfide alarm must be audible throughout the drilling location, including the camp buildings.
2. A gas detection system that continuously performs self-checking or diagnostics must be function-tested when a BOP stack is initially installed after a drill rig is set up when a commission-witnessed BOP test occurs, and no less frequently than once every six months. If a BOP stack is not required, a gas detection system that continuously performs self-checking or diagnostics must be function-tested when drilling or workover operations begin, when a commission-witnessed BOP test occurs, and no less frequently than once every six months. Other gas detection systems must be calibrated and tested when a BOP stack is initially installed after a drill rig is set up when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. If a BOP stack is not required, other gas detection systems must be calibrated and tested when drilling or workover operations begins when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. The operator shall maintain at the drill rig an accessible record of gas detection system tests and calibrations.
 3. A failure in a gas detection system must be reported to the commission within 24 hours after the failure. The commission will, in its discretion, require well operations to be discontinued if a gas detection system fails.
 4. Upon request of the operator, the commission may:
 - (1) waive the methane detection requirements of this section, if the commission determines that the configuration of the drilling or workover rig and any associated equipment and structures eliminates the potential for methane to accumulate;
 - (2) allow the use of a single hydrogen sulfide sensor on site in place of the three sensing points required under (a)(3) of this section, if the commission determines that the configuration of the drilling or workover rig and any associated equipment and structures eliminates the potential for hydrogen sulfide to accumulate; or

- (3) approve a variance from the requirements of this section if the variance provides at least an equally effective means of gas detection.

History - Eff. 11/7/99, Register 152; am 7/18/03, Register 167, October 2003

Authority - AS 31.05.030

20 AAC 25.066

Water and Drilling Waste Disposal

1. State agencies that control disposal of produced salt water and drilling wastes: Alaska Oil and Gas Conservation Commission and Alaska Department of Environmental Conservation. The Alaska Oil and Gas Conservation Commission regulates the U.I.C. Class II well Underground Injection Program in Alaska and the annular disposal of drilling waste.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: No minimum required.
 - (b) Royalty interest: No minimum required.

Taxation

(Note: Alaska's oil and gas severance taxes are actually titled as oil and gas production taxes - i.e., taxes on the activity of producing the oil and gas, which includes mechanical separation and other handling at the surface in the course of rendering the oil and gas marketable after severance from the ground.)

A comprehensive summary of Alaska's Oil and Gas severance taxes can be found on the internet at the following address: <http://www.tax.state.ak.us/programs/oil/programs/ogproduction/index.asp> and www.tax.state.ak.us/sources/index.asp.

Gas severance tax rates vary according to field average well productivity (Nominal rate multiplied by Economic Limit Factor (ELF) for gas). There is also a minimum tax of \$0.064/mcf that is also subject to the ELF.

Nominal rate = 10%

Gas severance tax rate = 0.0% to 10.0%

Oil severance tax rates vary according to a combination of field average well productivity and production rate (Nominal rate multiplied by the ELF for oil).

Nominal rate = 12.25% for fields in production less than 5 years and 15% for fields in production for more than 5 years.

There is also a minimum tax of \$0.80/barrel that is subject to the ELF.

Oil severance tax rate = 0.0% to 15.0%

Average effective rate statewide FY 2000 = 9.9% of taxable value. State and federal royalties are exempt from the tax.

1. Tax collecting agency: State of Alaska, Tax Division, Department of Revenue, 550 West Seventh Avenue, Suite 500, Anchorage, AK 99501.
2. How tax is computed:
 - (a) Valuation of production - The value of oil and gas for most tax purposes is computed using a net-back method. The delivery price has transportation charges subtracted from it to arrive at the field price on which the tax is

based.

- (b) Nominal production tax rates - The gas tax nominal rate is 10% of the gross value at the point of production. The oil tax nominal rate is 12.25% of the gross value at the point of production for fields in production less than 5 years and 15% of gross value at the point of production for fields in production for more than 5 years.
 - (c) Minimum production tax rates - The amount of severance tax due the state is computed by taking the greater of the cents per unit volume minimum tax (\$0.064/mcf for gas and \$0.80/barrel for oil) or the percentage of value basis. Both the percent of value and the cents per barrel (or cents per mcf) tax are subject to the ELF.
 - (d) ELF adjustments to production tax rates - The nominal tax rates are subject to reduction determined by the ELF, which is calculated separately for oil and gas for each field. The ELF is an adjustment to the nominal tax rate specific to each producing property to account for well productivity - oil fields averaging 300 barrels/day per well or less have ELFs of zero and pay no production tax, nor do gas fields averaging 3000 mcf/day per well or less. As average well productivity rises above these threshold rates, the ELF increases and so does the tax rate. The oil ELF is also dependent on the size of the field, with higher ELFs and tax rates as field size increases. Conversely, very small oil fields pay little or no tax.
 - (e) Oil production surcharge - Alaska collects two production surcharges on taxable oil, one of two cents a barrel and the other three cents. The three cent surcharge is always in effect, but the two cent one is suspended when there is \$50 million or more in the Oil and Hazardous Substance Release Prevention and Response Fund. Neither surcharge is reduced by the ELF.
 - (f) Property taxes - Alaska imposes an oil and gas property tax (ad valorem tax at a rate of 20 mills, or two percent of the assessed value, on all petroleum exploration, production and pipeline transportation property located in Alaska. The Property Tax Group at the Department of Revenue is responsible for determining the assessed values each year for all taxable property. A municipality may levy and collect a local property tax on state assessed property within its municipal boundaries, at the same rate of tax that it applies to other property that it taxes.
 - (g) Property taxes imposed by municipalities can be credited against the state property tax.
3. Exemptions or exceptions: The State of Alaska receives a royalty share of oil and gas production from state lands, which is exempt from the production tax and the oil surcharges. Federal royalty on production from federal lands in Alaska is likewise exempt from the tax and oil surcharges.
 4. Name of tax: Oil Production Tax; Gas Production Tax; Corporation Income Tax; Property Tax; Conservation Surcharge.
 5. Statutory citation: Oil production tax - AS 43.55.011; Gas production tax - AS 43.55.016; Oil and gas ELFs - AS 43.55.013; Oil production surcharges - AS 43.55.201 (two cents), AS 43.55.301 (three cents); State property tax - AS 43.56.010; Municipal property taxes on petroleum property - AS 29.45.080.

Land Leasing Information

1. Leasing Method:
 - Conventional lease sales: Competitive; several leasing options - combinations of fixed and variable bonus bids, royalty shares and net profit shares. Generally, a cash bonus bid with a fixed royalty share.
 - Oil and gas exploration licensing: competitive bids upon an obligation to perform a specified work commitment expressed in dollars of direct exploration expenditures.
2. Notice Method: Advertisement - Alaska Administrative Journal, State of Alaska Online Public Notice website, DO&G website, mailing list, newspapers.
3. Minimum bidding \$ (per acre)
 - Conventional lease sales: Generally \$5 to \$10 per acre bonus bid plus annual rental increasing from \$1 to \$3 per

acre over 5 years.

Oil and gas exploration licensing: competitive bid plus licensee's payment to the state of a non-refundable oil and gas exploration license fee of \$1 for each acre of land or fraction of each acre that is subject to the exploration license.

4. Qualification of the bidder: Every individual, association or partnership, corporation, LLC or person who is authorized to act on behalf of another party must qualify with the Division of Oil and Gas prior to bidding for lease tracts. Qualification must also be obtained prior to applying for, obtaining, or transferring interest in a permit or lease issued under AS 38.05.135 - 38.05.184.

5. State Statutes: AS 38.05.180 Oil and Gas Leasing
AS 38.05.131 Oil and Gas Exploration Licenses

Alaska Administrative Code: Title 11. Chapter 82. Mineral Leasing Procedures.

6. Maximum acres:

Oil and Gas Leasing: an oil and gas lease may not exceed 5,760 acres. One lessee may not hold oil and gas leases totaling more than 750,000 acres onshore (500,000 north of the Umiat baseline) and 500,000 acres offshore at any one time.

Oil and gas exploration licensing: one exploration license may cover an area of not less than 10,000 acres and not more than 500,000 acres that must be reasonably compact and contiguous; licensee may not hold more than 2,000,000 acres at any one time.

Shallow natural gas leasing: any one area to be leased may not exceed 5,760 acres; a lessee may not hold more than 46,080 acres of land leased in this manner.

7. Contact: Bruce Anders
E-mail: bruce.anders@alaska.gov
Website Reference: State of Alaska Department of Natural Resources, Division of Oil and Gas "Five-Year Oil and Gas Leasing Program, January 2007" posted on <http://www.dog.dnr.state.ak.us/>

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Oil and Gas Conservation Commission, 333 W. 7th Ave., AK 99501-3192. Phone: (907) 279-1433, Fax: (907) 276-7542.
2. Relevant Statute/Regulations: Alaska does not have NORM regulations. NORM is not much of a problem in Alaska. What little we have has a low count. NORM waste is either injected as a Class II fluid or incorporated in cement slurry. Some contaminated pipe has been shipped to approved disposal facilities outside of the State of Alaska.
3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:

10. Projected Volume of stored NORM in the State:

11. Respondent: John K. Norman

ARIZONA

Administration

1. State agency: Oil & Gas Program Administrator, Arizona Geological Survey, 416 W. Congress, Suite 100, Tucson, AZ 85701. Phone (520) 770-3500.
2. Docketing procedure: The Arizona Oil and Gas Conservation Commission meets approximately every few months. Formal hearings as requested by any interested person, or on motion by the Commission. ARS 27-517.
 - (a) Emergency orders: Yes. The emergency order shall remain in force not to exceed 30 days from its effective date. ARS 27-516.
 - (b) Notice: Ten days prior to hearing by the Chairman of the Commission. ARS 27-516.

Bond

1. Compliance bond required: Yes. Rule R12-7-103.
2. Conditions of bond: Release of bond contingent upon operator's compliance with all rules and regulations of the Commission.
 - (a) Amount per well: \$10,000 for well depth less than 10,000 feet, and \$20,000 for depth greater than 10,000.
 - (b) Amount of blanket bond:
 - \$25,000 for 10 or fewer wells;
 - \$50,000 for more than 10 but fewer than 50 wells; or
 - \$250,000 for 50 or more wells.

Spacing

1. Spacing requirements: Yes. Rule R12-7-107.
 - (a) Density: Minimum acreage for an oil well is 80 acres. Minimum acreage for a gas well is 640 acres.
 - (b) Lineal: No oil well shall be located closer than 330 feet from the boundary of drilling unit, nor closer than 330 feet to the shortest center line of drilling unit. Gas well no closer than 1,660 feet from section line.
2. Exceptions: Only after approval by Commission following notice and hearing. Rule R12-7-107(F).
 - (a) Basis: Topographical or geological conditions, and in order to prevent waste.
 - (b) Approval: Request public hearing to present evidence of necessity, and to give all interested parties a chance to be heard.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes. Rule R12-7-107(G), ARS 27-505.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes. Rule R12-7-104.

- (b) Seismic drilling: No permit is required, but holes must be plugged in an approved manner and a report filed with the Commission. Rule R12-7-127(J).
 - (c) Recompletion: Yes. Rule R12-7-122.
 - (d) Plugging and abandoning: Yes. Rule R12-7-126.
2. Permit fee:
- (a) Drilling: \$25.
 - (b) Seismic drilling: No
 - (c) Recompletion: No fee except re-entry of well previously plugged. Rule R12-7-122.
 - (d) Plugging and abandoning: No.
3. Require filing report of work performed: Yes. Rule R12-7-121 (A), R12-7-122(D), R12-7-127(I) and (J).

Vertical Deviation

1. Regulation requirement: Rule R12-7-115. (Notice and hearing required)
- (a) When is directional survey necessary? When a well is intentionally deviated from its normal course. Rule R12-7-115.
 - (b) Filing of survey required: Within 30 days of completion of the directionally drilled well. Rule R12-7-115(E).

Casing and Tubing

1. Minimum amount required:
- (a) Surface casing: Below all known and reasonably estimated fresh water. Rule R12-7-110(A).
 - (b) Production casing: Yes. Rule R12-7-111.
2. Minimum amount of cement required:
- (a) Surface casing: Circulate. Rule R12-7-110(A).
 - (b) Production casing: Yes. Rule R12-7-111.
 - (c) Setting time: Yes. Twelve hours minimum. Rules R12-7-110 and R12-7-111.
3. Tubing requirements:
- (a) Oil Wells: Yes. Rule R12-7-111.
 - (b) Gas Wells: Yes. Rule R12-7-111.

Tubing set as close to bottom as practical and tubing perforations not more than 250 feet above top of pay. Wells may be completed with small diameter casing in lieu of tubing. Rule R12-7-111.

Completion

1. Completion report required: Yes. Rule R12-7-121.
 - (a) Time limit: 30 days following completion. Rule R12-7-121.
 - (b) Where submitted: Oil & Gas Program Administrator, Arizona Geological Survey, 416 W. Congress, Suite 100, Tucson, AZ 85701.
2. Well logs required to be filed: Yes. Rule R12-7-121.
 - (a) Time limit: 30 days following completion. Rule R12-7-121.
 - (b) Where submitted: Same as (b) in question 1 above.
 - (c) Confidential time period: Yes. Rule R12-7-121(D). One year.
 - (d) Available for public use: Yes, after confidentiality period.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes. Rule R12-7-116.
 - (a) Approval obtained: Yes, after notice and hearing. Commission may administratively approve subsequent applications for multiple completions of same zones or reservoirs in a field. Rule 12-7-116(C).
4. Commingling in well bore: May be authorized by Commission upon application and hearing. Rule R12-7-137.

Oil Production

1. Definition of an oil well: Any well producing hydrocarbons in a liquid state that is not the result of condensation of gas, with a gas-oil ratio below 50,000 to 1, or any well classed as an oil well by the Commission.
2. Potential tests required: Yes. Rule R12-7-135(C).
 - (a) Time interval: Within 30 days following completion of well.
 - (b) Witnesses required: In some instances.
3. Statewide allowable: No. The Commission may prorate production to prevent waste or to protect correlative rights. ARS 27-516(13).
 - (a) Pool allowable: No
 - (b) Well allowable: No
 - (c) Exempt allowable:
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Yes, in order to prevent waste. ARS 27-516(A)(5).
 - (b) Exception to limiting gas-oil ratio: Yes, by establishing GOR limits. ARS 27-516(A)(5).
5. Bottom-hole pressure test reports required: Yes. Rule R12-7-136.
 - (a) Periodical bottom-hole pressure surveys: When required by Commission.

6. Commingling oil in common facilities: Yes. Only when leases have same royalty owners with identical percentage values and oil produced from same reservoir.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: No
 - (b) By well: Yes. Rule R12-7-161.
 - (c) Time limit: 25 days following the month of production.

Gas Production

1. Definition of a gas well: Gas well means any well which produces a GOR in excess of 50,000 to 1, or any well classed as a gas well by the Commission.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes. Rule R12-7-150.
 - (a) Time interval: Within 30 days after completion.
 - (b) Witness required: In some instances.
4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowables:
5. Bottom-hole pressure test reports required: Yes. Rule R12-7-136.
 - (a) Periodical bottom-hole pressure surveys: As required by Commission.
6. Commingling of gas in common facilities: No.
7. Measurement involving meters: Yes. Rule R12-7-151.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Rule R12-7-161.
 - (c) Time limits: 25 days following the month of production.

Water Disposal

1. State agencies that control disposal of produced salt water: Arizona Oil and Gas Conservation Commission, in class-II injection wells, and Arizona Department of Environmental Quality.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. ARS 27-531.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 63% exclusive of royalty interest owned by lessees or subsidiaries of lessees.
 - (b) Royalty interest: 63% exclusive of royalty interest owned by lessees or subsidiaries of lessees.

Taxation

There is a Transaction Privilege Tax on gross income from oil and gas production. ARS 42-5072.
Transaction Privilege Tax rate for 2005 was 3.437%.

There is an Ad Valorem tax assessed on 25% of gross income from oil and gas production. ARS 42-15001.
Ad Valorem Tax rate for 2005 was 5.5748%.

Total average tax burden for 2005 was 9.0118%.

Land Leasing Information

1. Leasing Method: Noncompetitive lease sale.
2. Notice Method: No notice is required for noncompetitive leasing sale under ARS 27-555. Notice is required if the Land Department designates a known geologic structure of producing oil or gas under ARS 27-554. Leasing is by sealed bids under ARS 27-556 within the designated area and notice must be published twice in a newspaper in the state not less than 15 days prior to the date fixed for opening the bids.
3. Minimum bidding \$ (per acre): Rental payment for the first year - the leases shall provide for the payment in advance of an annual rental of \$1.00/acre for each year of the primary term of the lease. All leases shall provide for a minimum rental of \$40.00 per year.
4. Qualification of the bidder: Individuals must be at least 21 years of age.
5. State Statutes: §27-554
§27-555
6. Maximum acres: Generally not more than 2,560 acres of land confined to an area of six miles square shall be in any one lease.
7. Contact: Steve Rauzi
steve.rauzi@azgs.az.gov
Phone: (520) 770-3500

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Arizona Radiation Regulatory Agency, 4814 S. 40th St., Phoenix, AZ 85048, Phone: (602) 255-4845, ext. 222.
2. Relevant Statute/Regulations: R12-1-416(F) - Individuals may apply to other exempt levels.
3. Scope: All radioactive materials.
4. Licensing: It is required for possession in excess of limits.
5. Cleaning Equipment:

6. Disposal of Waste: Unless exempt must have approved disposal.
7. Subsequent use of Equipment: Depending on levels, controls may apply.
8. Subsequent use of Materials: Depending on levels, controls may apply.
9. Release/sale of NORM-Contaminated Land: Depending on levels.
10. Projected Volume of stored NORM in the State:
11. Respondent: Aubrey Godwin

ARKANSAS

Administration

1. State agency: Arkansas Oil and Gas Commission, 301 Natural Resources Drive, Little Rock, AR 72205. Phone (501) 683-5814.
2. Docketing procedure: Applications for hearings are required to be filed no less than 20 days prior to the date of the hearing. Hearings are scheduled for the fourth Tuesday of each month. Filing fee is \$500.00 as of 1/1/01.
 - (a) Emergency orders: The Commission can issue an emergency order without a hearing. Said order remains in force no more than 10 days.
 - (b) Notice: Ten Days. Applicant supplies names and addresses of interested parties. Applicant mails notice to interested parties and provides to the Commission an affidavit of notice and a proof of publication in a newspaper of general circulation in the county(ies) containing the subject property or units. .

Bond

1. Compliance bond required: Yes. (Or Irrevocable Letter of Credit).
2. Conditions of bond:
 - (a) Amount per well: Minimum of \$3,000 per well, maximum of \$25,000.
 - (b) Amount of blanket bond:

<u>No. of Wells</u>	<u>Principal Sum</u>
1-25	25,000.00
26-100	50,000.00
over 100	100,000.00
 - (c) Seismic: \$50,000, not to exceed \$250,000.

Spacing

1. Spacing requirements:
 - (a) Density: No minimum for oil or gas wells in uncontrolled areas. Gas units are normally 640 acre governmental sections with exceptions.
 - (b) Lineal: A minimum of 280' from a governmental division line or lease line or property line for oil or gas wells. (For wildcat wells and wells drilled in fields not covered by field rules.) Oil spacing varies while gas is normally 1320 feet from the unit line with exceptions.
2. Exceptions: Yes.
 - (a) Basis: If a well drilled at a different location is likely to prevent waste or protect correlative rights of owners within the unit, or both.
 - (b) Approval: A public hearing must be held and ruling granted by the Commission. Administrative exceptional locations can also be granted, with a notice given to the parties having the right to drill in the unit being encroached, if no objections are filed within 15 days of publication of notice in certain circumstances

Pooling

1. Authority to establish voluntary: Yes.

2. Authority to establish compulsory: Yes, Act 536 of 1963. A.C.A. 15-72-303.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes.
 - (b) Seismic drilling? Yes.
 - (c) Recompletion? No.
 - (d) Plugging and abandoning? No.
2. Permit fee:
 - (a) Drilling: \$300
 - (b) Seismic drilling: minimum \$250, maximum \$500.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? When a wellbore is thought to have deviated in excess of 3 degrees from the vertical.
 - (b) Filing of survey required? (a) in all cases where the operator has proposed to deliberately drill a directional well from an exceptional surface location and/or to an exceptional bottom hole location; (b) prior to a permit being issued, if an off-set operator requests a directional survey and agrees in writing to pay all costs and expenses of such survey and to assume liability for all risks associated with the survey and further posts a bond in sufficient sum as determined by the Commission as security against all costs and risks associated with the survey or, (c) at any time, by order of the Commission, if the Commission is first presented with substantial evidence that it is likely that the well was drilled other than at the location permitted or that the well has deviated in the direction of a unit boundary to a bottom location which would necessitate an increased penalty upon the well's production allowable.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes.
 - (b) Production casing: Yes.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes.

- (b) Production casing: Yes.
- (c) Setting time: Yes, minimum 24 hours unless accelerators are used.
- 3. Tubing requirements:
 - (a) Oil wells: Yes.
 - (b) Gas wells: No.

Completion

- 1. Completion report required: Yes.
 - (a) Time limit: Within 30 days of completion date and prior to commencement of production.
 - (b) Where submitted: Appropriate Arkansas Oil and Gas Commission Regional Office.
- 2. Well logs required to be filed: Yes.
 - (a) Time limit: Within 30 days of completion date and prior to commencement of production.
 - (b) Where submitted: Appropriate Arkansas Oil and Gas Commission Regional Office.
 - (c) Confidential time period: Yes, maximum of 90 days from completion date.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
- 3. Multiple completion regulation: Yes.
 - (a) Approval obtained: Wells may be completed as a multiple completion if the Commission staff is assured that the zones are separated in the wellbore by approved methods.
- 4. Commingling in well bore: Yes.
 - (a) Approval obtained: Gas wells – commingling authorized in certain circumstances by Rule. Oil wells -A fieldwide hearing is held to consider the feasibility of commingling marginal zones. If it appears feasible, the Commission staff is authorized to review and approve or disapprove application for commingling on an individual well basis.

Oil Production

- 1. Definition of an oil well: any well capable of producing oil in paying quantities not a gas well. An oil well is considered to be a well completed in a reservoir containing liquid hydrocarbons at original reservoir conditions (pressure, temperature, etc.)
- 2. Potential tests required: Yes.
 - (a) Time interval: At commencement of production.
 - (b) Witness required: Initial tests are witnessed on high gas-oil ratio wells.
- 3. Statewide allowable: No.
 - (a) Pool allowable: Yes. Each well within a defined pool is assigned an allowable deemed to be the most efficient

rate of production for a well completed in that type pool.

- (b) Well allowable: Yes. See above.
 - (c) Exempt allowable: Yes. Some wells may be exempt from allowable restrictions if approved by the Commission after having received supporting evidence at a public hearing, or if the wells produce from pools discovered prior to January 1, 1937.
4. Maximum gas-oil ratio: Yes. The standard gas-oil ratio is 2000/1.
- (a) Provision for limiting gas-oil ratio: Yes. Wells are penalized if the GOR exceeds the 2000/1 GOR limit (or the limiting GOR as set out in a specific Field Rule Order). The allowable is

$$\text{Bbls/day} = \frac{\text{Bbls (Normal Oil Allowable)} \times 2000 \text{ (or limit in Field Rule Order)}}{\text{Actual Producing GOR}}$$
 - (b) Exception to limiting gas-oil ratio: Yes. The Commission may approve a higher GOR limit for a pool after public hearing.
5. Bottom-hole pressure test reports required: The initial BHP is listed on the Completion Report.
- (a) Periodical bottom-hole pressure surveys: Only in pools that have volumetric formulas used in allowable computations.
6. Commingling oil in common facilities: Yes. Upon proof that production is produced from wells having common ownerships, unless specifically prohibited by Field Rule Order.
7. Measurement involving meters: Yes. Measurement of oil by meters must be approved by the Commission after a public hearing.
8. Production reports:
- (a) By lease: Yes. Purchase reports uncontrolled production by lease on a monthly basis.
 - (b) By well: Yes. Operator reports controlled production by well on a monthly basis with the exception of unitized pools.
 - (c) Time limit: On or before the 15th of the next succeeding month.

Gas Production

1. Definition of a gas well: (1) a well which produces natural gas only; (2) any well capable of producing gas in commercial quantities and also producing oil from the same common source of supply but not in commercial quantities; (3) any well classed as a gas well by the Arkansas Oil and Gas Commission for any reason; or (4) a well that contains no liquid hydrocarbons in the reservoir. A gas well is considered to be a well completed in a reservoir containing hydrocarbons in a gaseous state at original reservoir conditions.
2. Pressure base 14.65 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: Within 10 days after a new well has commenced production.
 - (b) Witness required: Yes.
4. Statewide allowable: No.

- (a) Pool allowable: Yes. By Quarterly and Annual Production Permissive.
 - (b) Well allowable: Yes. See explanation above.
 - (c) Exempt allowable: Yes. Some wells may be exempt from allowable restrictions if approved by the Commission after having received supporting evidence at a public hearing, or if the wells produce from pools discovered prior to January 1, 1937.
5. Bottom-hole test reports required: No, however, annual back pressure test is required.
- (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: Yes, with AOGC approval.
7. Measurement involving meters: Yes.
8. Production reports: Yes.
- (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Within 45 days following month of production.

Water Disposal

1. State agencies that control disposal of produced salt water: Oil and Gas Commission and Department of Environmental Quality work together. Oil and Gas Commission handles the underground disposal and Department of Environmental Quality handles surface disposal.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
- (a) Working interest: 75%.
 - (b) Royalty interest: 75% of royalty and overriding interests.

Taxation

Gas severance tax = 0.3 of 1 cent per MCF

Gas ad valorem tax = variable by county

Gas conservation assessment = 9 mills per MCF

Total gas tax burden = 0.3 of 1 cent per MCF + county ad valorem tax

Oil severance tax = 4.0% to 5.0%, depending on production levels

Oil ad valorem tax = variably by county

Oil conservation assessment = 43 mills per bbl

Total oil tax burden = 4.0% to 5.0% + county ad valorem tax

1. Tax collecting agencies: Severance Tax - Department of Finance and Administration, Revenue Division, Miscellaneous Tax Section, Box 1272, Little Rock, AR 72203. Conservation Tax - Arkansas Oil and Gas Commission, P. O. Box 1472, El Dorado, AR 71731-1472.

2. How tax is computed:
 Gas severance tax – 0.3 of 1 cent per MCF
 Gas conservation assessment – 9 mills per MCF of produced gas

 Oil severance tax – 5.0% if greater than 10 barrels of oil per day; 4.0% if less than 10 barrels of oil per day
 Oil conservation assessment – 43 mills per bbl
3. Exemptions or exceptions: Severance Tax - Yes, for discovery well, and re-establishment of production from an idle well. Conservation Assessment - none.
4. Name of tax: Severance Tax and Conservation Assessment.
5. Statutory citation: Act 136 - Amended; ACT 105-1939.

Land Leasing Information

1. Leasing Method: Sealed bids.
2. Notice Method: In a newspaper of general circulation in this state for no fewer than 3 consecutive days and in a newspaper of general circulation in the county in which the property is located for not less than 1 day, a notice that an application has been filed.
3. Minimum bidding \$ (per acre): No statutory or set minimum bid amount. State looks at each application on a case by case basis and takes recommendations from the State Oil and Gas Commission staff.
4. Qualification of the bidder: Any person, firm, company, corporation or association.
5. State Statutes: §22-5-805
 §22-5-806
 §22-5-808
6. Maximum acres: 1,500 acres.
7. Contact: Commissioner of State Lands Offices
 109 State Capitol
 Little Rock, AR 72201
 Main Number: 501-324-9222

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Health, Division of Radiation Control and Emergency Management, 4815 W. Markham Street, Little Rock, AR 72205-3867. Phone: (501) 661-2108.
2. Relevant Statute/Regulations: Section 7 "Naturally Occurring Radioactive Material (NORM)" of the Arkansas State Board of Health Rules and Regulations for Control of Sources of Ionizing Radiation.
3. Scope: Radiation protection standards for possession, use, transfer, and disposal of NORM. These regulations address NORM into products in which neither the NORM nor the emitted radiation is considered to be beneficial to the products. Regulations address waste management and disposal standards.
4. Licensing: General licenses are issued to mine, extract, receive, possess, own, use, process and dispose NORM. (RH-6010). Specific license for manufacturing and distribution of any NORM product for activities involving the remediation of equipment and/or facilities contaminated with NORM and the disposal of NORM waste. (RH-6020).
5. Cleaning Equipment: Equipment contaminated with NORM in excess of levels listed in Appendix A, Section 7 and

having maximum radiation exposure levels greater than 50 microR per hour including background shall NOT be released for unrestricted use. (RH-6010.b.).

6. Disposal of Waste: RH-6013 to a licensed disposal facility or in accordance with an alternate method approved by the Department.
7. Subsequent Use of Equipment: Equipment contaminated with NORM is exempt if the maximum radiation exposure level does not exceed 50 microR including background or radioactive contamination levels do not exceed requirements of Appendix A of Section 7 (RH-6010.d.).
8. Subsequent Use of Materials: RH-6023 requires that during the normal use and disposal that the radiation dose in any one year or the dose committed from intake of NORM will not exceed the doses of Column I of RH-6024.
9. Release/Sale of NORM-Contaminated Land: Requires that an annotation of the deed records to indicate the presence and quantity of NORM (RH-6010.f.1.B.).
10. Projected Volume of stored NORM in the State: Unknown.
11. Respondent: Jared Thompson
12. Regulating Agency: Arkansas Oil and Gas Commission, 301 Natural Resources Drive, Little Rock, AR 72205. Phone (501) 683-5814. Fax: (501) 683-5818.
13. Relevant Statute/Regulations: The Oil and Gas Commission does not have regulations concerning NORM whether it be found in pipe and scale or soil and sediment.
14. Scope: The Oil and Gas Commission may become involved with NORM disposal if an operator desires to dispose of the waste by well injection.
15. Licensing: Not applicable - see ADH
16. Cleaning Equipment: Not applicable - see ADH
17. Disposal of Waste: May work jointly with ADH if applicant desires to use injection or down hole disposal.
18. Subsequent Use of Equipment: Not applicable.
19. Subsequent Use of Material: Not applicable.
20. Release/Sale of NORM-Contaminated Land: Not applicable.
21. Projected Volume of stored NORM in the State: Unknown.
22. Respondent: Gary Looney

CALIFORNIA

Administration

1. State agency: California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, 801 K Street, MS 20, Sacramento, CA 95814-3530. Phone (916) 445-9686.
2. Docketing procedure: Hearings as needed. Notice of hearing sent to all concerned and interested parties and published in at least one newspaper of general circulation.
 - (a) Emergency orders: Yes. When the State Oil and Gas Supervisor determines that an emergency exists. (Section 3226).
 - (b) Notice: 20 days (may be as many as 30 days, depending on type of hearing). The Director of Conservation or the State Oil and Gas Supervisor is responsible to give notice, depending upon the type of order.

Bond

1. Compliance bond required: Yes. (Sections 3204-3209).
2. Conditions of bond: Required when an operator is about to drill, redrill, deepen or permanently alter a well; operate a commercial Class II disposal well; acquire an idle well; or maintain an idle well - (Idle is defined as five or more years.)
 - (a) Amount per well: Onshore - less than 5,000 feet, \$15,000; 5,000 feet but less than 10,000 feet, \$20,000; 10,000 feet or greater depth, \$30,000. Individual coverage for offshore well is not acceptable.
 - (b) Amount of onshore blanket bond:
 - (1) \$100,000 for 50 or fewer wells (does not include the bond or fee required for idle wells).
 - (2) \$250,000 for more than 50 wells (does not include the bond or fee required for idle wells).
 - (3) \$1 million bond to cover all oil and gas operations, including idle wells.
 - (c) All newly acquired idle wells are to be covered by individual or blanket indemnity bonds.
 - (d) With State Oil and Gas Supervisor approval, a provision for cash deposit in lieu of an indemnity bond for wells is provided. (Section 3205.5)
 - (e) Any idle well not covered by an individual or \$1,000,000 blanket bond shall:
 - (1) Pay an annual fee for each idle well, based on the length of time a well has been idle -- \$100 for each well idle less than 10 years, \$250 for each well idle between 10 and 15 years, or \$500 for each well idle 15 years or longer; or
 - (2) Establish an escrow account equivalent to \$5,000 for each idle well, with the required deposit funded completely within ten years; or
 - (3) File a \$5,000 indemnity bond for each idle well; or
 - (4) Establish an idle-well management plan that requires an operator to eliminate a certain percentage of long-term idle wells (those idle 10 years or longer) annually.
 - (f) Amount of offshore blanket bond; \$250,000 (no individual bonds are permitted for offshore wells).

- (g) Amount for commercial Class II disposal well: \$50,000 or a blanket bond pursuant to Section 3205(a) or (c).

Spacing

1. Spacing requirements: Yes. (Sections 3600-3609).
 - (a) Density: One well per acre for fields producing after August 14, 1931, or as approved or ordered by the Supervisor for pools discovered after Jan. 1, 1974.
 - (b) Lineal: See Sections 3600-3606.1 does not apply to fields producing on August 14, 1931. Applies to both oil and gas wells.
2. Exceptions: Yes.
 - (a) Basis: For drilling islands and developing heavy hydrocarbons that necessitate closer well spacing. (Section 3602.1).
 - (b) Approval: Through appeal to the State Oil and Gas Supervisor.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Under certain conditions (following petition to adopt a well-spacing plan other than that stated in Sections 3600-3608.1).

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes. (Section 3203).
 - (b) Seismic drilling? No. (Permitting may be required by local agencies.)
 - (c) Recompletion? Yes. (Section 3203).
 - (d) Plugging and abandoning? Yes. (Section 3229).
2. Permit fee: None required.
 - (a) Drilling: N/A.
 - (b) Seismic drilling: N/A.
 - (c) Recompletion: N/A.
 - (d) Plugging and abandoning: N/A.
3. Require filing report of work performed: Yes. (Sections 3215 & 3232).

Vertical Deviation

1. Regulation requirement: Yes. (Section 3606).
 - (a) When is directional survey necessary? For all wells drilled directionally.
 - (b) Filing of survey required? Yes. (Section 3215).

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes. (See California Code of Regulations).
 - (b) Production casing: Yes, when required. (Barefoot completions are still permitted.)
2. Minimum amount of cement required:
 - (a) Surface casing: Yes. Fill annular space from shoe to the surface.
 - (b) Production casing: Yes. At least 500 feet fill above oil and gas zones and anomalous pressure intervals, and to at least 100 feet above the base of freshwater zone.
 - (c) Setting time: No.
3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.
 - (c) Injection wells: Yes. (Exemptions are allowed.)

Completion

1. Completion report required: Yes. (Section 3215).
 - (a) Time limit: Within 60 days after such completion.
 - (b) Where submitted: To the appropriate district office of the Division of Oil, Gas, and Geothermal Resources.
2. Well logs required to be filed: Yes. (Section 3215).
 - (a) Time limit: Within 60 days after completion.
 - (b) Where submitted: To the appropriate district office of the Division of Oil, Gas, and Geothermal Resources.
 - (c) Confidential time period: If requested. (Section 3234). Not to exceed two years for onshore exploratory wells and not to exceed five years for offshore exploratory wells. Period may be extended for exploratory and offshore wells upon a showing of extenuating circumstances. Development wells may be granted confidential status if the Supervisor determines there are extenuating circumstances.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes.
3. Multiple completion regulation: No.
 - (a) Approval obtained: N/A.
4. Commingling in well bore: Yes.
 - (a) Approval obtained: Commingled production could be stopped if it is proven that such practices are detrimental to

the pools.

Oil Production

1. Definition of an oil well: "Well" means any oil or gas well or well for the discovery of oil or gas; any well on lands producing or reasonably presumed to contain oil or gas; any well drilled for the purpose of injecting fluids or gas for stimulating oil or gas recovery, repressuring or pressure maintenance of oil or gas reservoirs, or disposing of waste fluids from an oil or gas field; any well used to inject or withdraw gas from an underground storage facility; or any well drilled within or adjacent to an oil or gas pool for the purpose of obtaining water to be used in production stimulation or repressuring operations.

Definition of a prospect well or exploratory well: "Prospect well" or "exploratory well" means any well drilled to extend a field or explore a new, potentially productive reservoir.

Definition of active observation well: "Active observation well" means a well being used for the sole purpose of gathering reservoir data, such as pressure or temperature in a reservoir being currently produced or injected by the operator, and the data is gathered at least once every three years.

Definition of idle well: "Idle well" means any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last five or more years. An idle well does not include an active observation well.

Definition of long-term idle well: "Long-term idle well" means any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last 10 or more years. Long-term idle well does not include an active observation well.

2. Potential tests required: No.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
3. Statewide Allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: N/A.
4. Maximum gas-oil ratio: Yes. Field rules are established.
 - (a) Provision for limiting gas-oil ratio: Yes. (Section 3307). Such production that may be considered unreasonable waste of natural gas. (Sections 3300-3314).
 - (b) Exception to limiting gas-oil ratio: Yes, unusual circumstances.
5. Bottom-hole pressure test reports required: Yes, if BHP recordings are made.
 - (a) Periodic bottom-hole pressure surveys: Same as above.
6. Commingling oil in common facilities: Yes.
7. Measurement involving meters: Yes.
8. Production reports:

- (a) By lease: No.
- (b) By well: Yes. (Section 3227).
- (c) Time limit: Within 30 days of end of reporting month.

Gas Production

1. Definition of a gas well: A well producing nonassociated gas.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: No.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: N/A.
5. Bottom-hole pressure test reports required: Yes, if BHP recordings are made.
 - (a) Periodic bottom-hole pressure surveys: Same as above.
6. Commingling of gas in common facilities: Yes.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. (Section 3227).
 - (c) Time limit: Within 30 days of end of reporting month.

Water Disposal

1. State agencies that control disposal of produced salt water: The Division of Oil, Gas, and Geothermal Resources is the lead agency for the regulation of Class II injection wells. The U.S. Environmental Protection Agency delegated federal authority to the Division in 1983. The State's Regional Water Quality Control Boards regulate surface disposal.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes, provisions as described in Sections 3630-3659. (For areas located in fields that have been producing for more than 20 years only.)

2. Minimum percentage of voluntary agreement before approval of compulsory unitization:

- (a) Working interest: 75%.
- (b) Royalty interest: 75%.

Taxation

Gas assessment tax = \$0.061889 per 10,000 cubic feet of gas
 Gas ad valorem tax = 0.0%
 Total gas tax burden = \$0.061889 per 10,000 cubic feet of gas

Oil assessment tax = \$0.061889 per barrel of oil
 Oil ad valorem tax = 0.0%
 Total oil tax burden = \$0.061889 per barrel of oil

- 1. Tax collecting agency: State Controller, Tax Collection and Refund Section, 3301 C Street, Room 300, Sacramento, CA 95816.
- 2. How tax is computed: Oil and gas tax is computed at a variable rate. The 2005-2006 rate is \$0.0538953 per barrel of oil or 10,000 cubic feet of gas. The rate is adjusted yearly to raise funds for the support of the Division of Oil, Gas, and Geothermal Resources.
- 3. Exemptions or exceptions: Gas used in pressure-maintenance or other producing operations is exempt from assessment.
- 4. Name of tax: Oil and Gas Assessment.
- 5. Statutory citation: Article 7, Chapter 1, Division 3, California Public Resources Code (Sections 3400-3433).

Land Leasing Information

- 1. Leasing Method: Sealed competitive bids.
- 2. Notice Method: At least once in a newspaper in the City of LA, SF, or Sacramento.
- 3. Minimum bidding \$ (per acre): No less than \$1.
- 4. Qualification of the bidder:
- 5. State Statutes: §1905, §1909, §2249, §6827, §6874.
- 6. Maximum acres:
- 7. Contact: Paul B. Mount
 Phone: (310) 590-5201
 E-mail: mountp@slc.ca.gov

Naturally Occurring Radioactive Material (NORM)

- 1. Regulating Agency: Department of Health Services, Radiological Health Branch, P.O. Box 942732, Sacramento, CA 94234-7320. Phone: (916) 322-3482, Fax: (916) 324-3610.
- 2. Relevant Statute/Regulations: California Health and Safety Code, Sections 114705-115270.
 California Code of Regulations, Title 17, Sections 30100-30543.

3. Scope: Addresses all radioactive materials but is not specific to NORM and NORM issues in oil and gas production.
4. Licensing: At the present time no decontamination, handling or disposal licenses specific to oil and gas industries and the associated NORM have been issued.
5. Cleaning Equipment: Not presently licensed. No inventory or companies involved.
6. Disposal of Waste: No regulations specific to oil and gas NORM disposal; however, NORM may be injected into a Class II disposal well. If NORM sets off alarms at disposal sites or recycle facilities (including steel mills) then waste is treated as radioactive waste.
7. Subsequent Use of Equipment: No specific regulations or restrictions at the present time.
8. Subsequent Use of Materials: No specific regulations or restrictions at the present time.
9. Release/Sale of NORM-Contaminated Land: No specific regulations or restrictions at the present time.
10. Projected Volume of stored NORM in the State: Unknown, but large due to geothermal pipelines.
11. Respondent: Steve Hsu

COLORADO

Administration

1. State agency: Oil and Gas Conservation Commission, 1120 Lincoln St., Suite 801, Denver, CO 80203. Phone (303) 894-2100. Fax (303) 894-2109.
2. Docketing procedure: Upon the filing of an application, a hearing will be scheduled in accordance with Rule 503. Hearings are normally set for every 5 weeks. No application fee. No protestor or intervenor fee.
 - (a) Emergency orders: Rule 502. The Commission may issue an emergency order without notice, but it shall remain effective for no more than 15 days.
 - (b) Notice: Rule 507. Minimum of 20 days by the Commission.

Bond

1. Compliance bond required: Yes. Rule 304 and Rules 702-711.
2. Conditions of bond: Compliance with laws and rules and regulations with reference to properly plugging wells. Separate surface restoration bond when landowner is not party to oil or gas leasing agreement.
 - (a) Amount per well: Plugging - \$5,000; Surface damage - \$2,000 on land not irrigated, \$5,000 on irrigated land.
 - (b) Amount of blanket bond: Plugging - \$30,000 for less than 100 wells; \$100,000 for 100 wells or more; Surface damage - \$25,000.
3. Seismic operations bond. \$25,000 blanket.

Spacing

1. Spacing requirements: Minimum density not specific.
 - (a) Density: Not specific.
 - (b) Lineal: Rule 318. Less than 2,500 feet in depth - 200 feet from lease line, 300 feet between wells with only one well allowed in each governmental quarter-quarter section. Greater than 2,500 feet - 600 feet from lease lines, 1,200 feet between wells for both oil and gas wells.
2. Exceptions: Yes.
 - (a) Basis: Geologic, environmental, topographic or archeologic conditions, irregular sections or surface conditions.
 - (b) Approval: Administratively if no objection or receipt of waivers from offset lease owners. (Rule 318.c.) Where lease owner of offset lease is the same as owner of proposed well, waiver must be obtained from offset mineral owners; however, waiver must be reasonable. If waivers cannot be obtained from all parties and no party objects, the operation may apply for a Director variance. (Rule 502.b.) If parties object, hearing before Commission.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes. Rule 530.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes. Rule 303.
 - (b) Seismic drilling? Yes. Rule 333.
 - (c) Recompletion? Yes. Rule 303.b.
 - (d) Plugging and abandoning? Yes. Rule 311.
2. Permit fee:
 - (a) Drilling: None.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes. Rule 307, Rule 308A, Rule 308B, Rule 311.
4. Local Government Entities. In June 1992, various rules became effective concerning notice of planned drilling activities to be furnished to those local governments (counties, towns, districts, etc.) that have advised the Commission of their interest. These rules include certain rules within the 100 series, Rule 214 and Rule 303. Subsequent rules were adopted to allow local governments to file for a commission hearing prior to issuance of a permit to drill based on a potential for significant impacts on public health, safety and welfare, including the environment. Rule 508 was effective July 30, 1998 allowing local governments to request a local public forum on applications that would result in more than one well site or multi-well site per 40 acres. In addition, Rules 801 through 804 were adopted concerning Aesthetics and Noise Control Regulation.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? Rule 321, when a directional hole is drilled other than whipstocking due to hole conditions; this includes highly deviated as well as horizontal boreholes.
 - (b) Filing of survey required? Yes, within 30 days.

Casing and Tubing

1. Minimum amount required: Rule 317 and Rule 317A.
 - (a) Surface casing: Yes.
 - (b) Production casing: No.
2. Minimum amount of cement required:
 - (a) Surface casing: Circulated to surface.
 - (b) Production casing: Yes. Set 200 feet above the top of the most shallow known producing formation.
 - (c) Setting time: Yes. Eight hours.

3. Tubing requirements:

- (a) Oil wells: No.
- (b) Gas wells: No.

Completion

1. Completion report required: Yes. Rule 308A and 308B.

- (a) Time limit: 30 days after completion.
- (b) Where submitted: Oil and Gas Conservation Commission, 1120 Lincoln St., Suite 801, Denver, CO 80203.

2. Well logs required to be filed: Yes.

- (a) Time limit: 30 days after completion.
- (b) Where submitted: Oil and Gas Conservation Commission.
- (c) Confidential time period: If requested, for six months after date of completion.
- (d) Available for public use: Yes.
- (e) Log catalog available: Yes.

3. Multiple completion regulation: No.

4. Commingling in well bore: Yes. Rule 322.

- (a) Approval not required unless the Commission has issued an order or promulgated a rule excluding specific wells, geologic formation, geographic areas, or field from commingling in response to an application filed by a directly and adversely affected or aggrieved party or on the Commission's own motion.

Oil Production

1. Definition of an oil well: 100 Series of rules. Oil well shall mean a well, the principal production of which at the mouth of the well is oil, as defined by the Act. The word "oil" shall mean crude petroleum oil and any other hydrocarbons, regardless of gravities, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir.

2. Potential tests required: Yes.

- (a) Time interval: Prior to sales.
- (b) Witness required: Only as may be required by Commission orders.

3. Statewide allowable: No.

- (a) Pool allowable: No.
- (b) Well allowable: Yes. In cases where a well is an exception to a spacing order, or after a finding of waste, the Commission can limit production and set well allowables.
- (c) Exempt allowable: No.

4. Maximum gas-oil ratio: No.

- (a) Provision for limiting gas-oil ratio: Yes. The statute provides the Commission with the authority to establish efficient ratios and limit production from wells with inefficient ratios.
- (b) Exception to limiting gas-oil ratio: Yes. Only as specified by Commission order.
- 5. Bottom-hole pressure test reports required: Usually not.
 - (a) Periodical bottom-hole pressure surveys: Only as directed by Commission.
- 6. Commingling oil in common facilities is allowed. Production must be reported by allocation.
- 7. Measurement involving meters: Rule 328. Use properly calibrated meter or tank measurements.
- 8. Production reports: Rule 309.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: 45 days from the end of the month for which production is reported.

Gas Production

- 1. Definition of a gas well: 100 Series of the rules. Gas well shall mean a well, the principal production of which at the mouth of the well is gas, as defined by the Act. The word "gas" shall mean all natural gases and all hydrocarbons not defined herein as oil.
- 2. Pressure base 14.73 psia @ 60 degrees F.
- 3. Initial potential tests: Yes.
 - (a) Time interval: Prior to sales.
 - (b) Witness required: Maybe.
- 4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: Only by ratable-take provisions.
 - (c) Exempt allowable: No.
- 5. Bottom-hole pressure test reports required: Usually not.
 - (a) Periodical bottom-hole pressure surveys: Only as directed by the Commission.
- 6. Commingling of gas in common facilities: No.
- 7. Measurement involving meters: Yes.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: 45 days from the end of the month for which production is reported.

Water Disposal

State agencies that control disposal of produced salt water: Rule 324B, 325, 326, and 330. Oil and Gas Conservation Commission. Commission has primacy from EPA for all Class II injection and disposal wells except those on Indian lands.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 80%.
 - (b) Royalty interest: 80%.

Taxation

Gas severance tax = 2.0% to 5.0%; depending on amount of gross income

Gas ad valorem tax = 4.0% to 10.0%; depending on county

Total gas tax burden = 5.0% to 10.0%

Oil severance tax = 2.0% to 5.0%; depending on amount of income

Oil ad valorem tax = 4.0% to 10.0%; depending on county

Total oil tax burden = 5.0% to 10.0%

1. Tax collecting agency: State Department of Revenue, Capitol Annex Building, 1375 Sherman Street, Denver, CO 80261.
2. How tax is computed:

Severance tax on oil and gas:

Gross Oil and Gas Income	Colorado Severance Tax Rate
Under \$25,000	2% of gross income
\$25,000 and under \$100,000	\$500 plus 3% of the excess over \$24,999
\$100,000 and under \$300,000	\$2,750 plus 4% of the excess over \$99,999
\$300,000 and over	\$10,750 plus 5% of the excess over \$299,999

Ad valorem rates vary from county to county ranging from 4% to 10%. Ad valorem taxes are paid by the producer to the local governments (cities and counties).

87.5% of ad valorem taxes are allowed as a credit against severance tax. Depending on the applicable severance and ad valorem tax rates, working or royalty interest owners can receive a full refund of severance taxes. As a result, the total production taxes paid can be limited to the ad valorem tax rate.

Ad valorem taxes paid on production from stripper wells (on which no severance tax was withheld) are not included in the deduction.

Note: Anytime 7/8ths of the ad valorem tax equals or exceeds the 5% severance tax, it cancels out the severance tax. If the ad valorem tax is less than the 5% severance tax, the severance tax is displaced.

3. Exemptions or exceptions:
 - (a) Any oil produced from wells that produce fifteen barrels per day or less for the average of all producing days during the taxable year shall be exempt from the tax.

- (b) Wells that produce ninety thousand cubic feet or less of gas per day for the average of all producing days for such production during the taxable year shall be exempt from the tax.

4. Name of tax: Severance.
5. Statutory citation: 39-29-105 Colorado Revised Statutes (1973, as amended).

Land Leasing Information

1. Leasing Method: Oral bid auction; the leases are issued to the highest bidder at quarterly auctions. The leases cannot be taken over the counter after the auction. They must be nominated again if not taken at the auction.
2. Notice Method: The auction announcement is mailed approximately one month prior to the auction, and is available on the Web site at www.trustlands.state.co.us.
3. Minimum bidding \$ (per acre): The first year's rental (\$1.50/per year) plus the statutory fee of \$20.00.
4. Qualification of the bidder: the bidder's residency does not matter, but the successful bidder must be authorized by the Secretary of State's office to do business in the State of Colorado. If residency is in a foreign country, lessee must have an agent in the United States.
5. State Statutes: CO ST
 - §22-32-112
 - §36-1-113
 - §36-1-118
 - §36-1-124
6. Maximum acres: no maximum
7. Contact: Timothy Kelly
Phone: (303) 866-3934
E-mail: timothy.kelly@state.co.us

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Public Health and Environment (CDPHE), 4300 Cherry Creek Drive, South, Denver, CO 80246-1530. Phone: (303) 692-3300, Fax: (303) 759-5355.
2. Relevant Statute/Regulations: The Radiation Control Regulations, Parts 1, 3, 4, 10, 12 and 17; C.K.S. 25-11-101 and 25-11-102 and TENORM Disposal Policy of February 2007.
3. Scope: The state has broad authority to control radioactive material. NORM is evaluated on a case by case basis. Colorado has had very few instances of NORM issues in the oil and gas industry. Most of our NORM is in the sedimentary rocks associated with uranium "roll fronts" and drinking water residuals.
4. Licensing: Case by case evaluation in accordance with the TENORM Policy if >25 mrem/yr or source material concentrations.
5. Cleaning Equipment: ALARA, Part 4, TENORM Policy reference ANSI N13.12.
6. Disposal of Waste: Soils on a case-by-case basis. Colorado is part of the Rocky Mountain Low Level Waste Compact and discrete radium must be disposed through the compact. Compact Rule 6 updated for TENORM in Rocky Mountain Compact. Policy has graded approach for disposal of TENORM as solid waste in some cases.
7. Subsequent Use of Equipment: Risk assessment of residual radioactivity
8. Subsequent Use of Materials: Risk assessment of residual radioactivity. . Policy addresses release/reuse.
9. Release/Sale or NORM-Contaminated Land: There have been no restrictions on the sale or release of land, but there are

institutional controls per the Environment Covenant Act for identified sites. <25 mrem/yr in accordance with Part 4.

10. Projected Volume of stored NORM in the State: Unknown.
11. Respondent: Phil Egidi for CDPHE. 222 South 6th Street, Room 232, Grand Junction, CO 81501 Phone: (970) 248-7162, Fax: (970) 248-7198, Cell (970) 209-2885.
12. Regulating Agency: Colorado Oil and Gas Conservation Commission, 1120 Lincoln St., Ste. 801, Denver, CO 80203. Phone: (303) 894-2100, Ext. 111, Fax: (303) 894-2109.
13. Relevant Statute/Regulations: None existing or proposed. TENORM Policy and Guidance February 2007.
14. Scope: COGCC has authority over E&P wastes but CDPHE has authority over disposal of low-level radioactive material.
15. Licensing: Can license.
16. Cleaning Equipment: See Policy.
17. Disposal of Waste: See Policy.
18. Subsequent Use of Equipment: See Policy.
19. Subsequent Use of Materials: See Policy.
20. Release/Sale of NORM-Contaminated Land: Unknown.
21. Projected Volume of stored NORM in the State: Unknown.
22. Respondent: Tricia Beaver

FLORIDA

Administration

1. State agency: Department of Environmental Protection, Division of Resource Assessment and Management, Florida Geological Survey, 903 W. Tennessee St., Tallahassee, FL 32304-7700. Phone (904) 488-4191/487-2219.
2. Docketing procedure: Hearings held on Department initiative by petition of a party of interest and after notice and publication (at least three weeks). Hearings held in office of Department unless otherwise designated. (F.S. 377.31)
 - (a) Emergency orders: Yes, in event the Division finds an emergency exists. Order effective for 90 days only or until public hearing on the issue.
 - (b) Notice: Division of Resource Assessment and Management must give minimum of three weeks public notice.

Bond

1. Compliance Surety required: Yes.
2. Conditions of bond: Restoration of drill site, compliance with rules and regulations be fulfilled, well be plugged and abandoned.
 - (a) Amount per well:

Well depth	Per well	For Producer
0-9,000	\$ 50,000	\$100,000
9,001-or more	100,000	200,000
 - (b) Amount of blanket bond: \$1,000,000 (10 well limit).

Spacing

1. Spacing requirements: Yes.
 - (a) Density: 40 and 160 acres for oil well and 640 for gas well.
 - (b) Lineal: Longest diagonal (of other than a square unit) may not exceed length of diagonal of a square of same size unit by more than 25% for both oil and gas wells.
2. Exceptions: Yes.
 - (a) Basis: - 10% of size of unit designated.
 - (b) Approval: Secretary of the Department of Environmental Protection.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:

- (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: Yes.
 - (c) Recompletion: No, provided bhl meets original condition of permit.
 - (d) Plugging and abandoning: Yes, prior authorization is required. No written DEP permit is issued.
2. Permit fee:
- (a) Drilling: \$2,000.
 - (b) Seismic Prospecting: \$500.
 - (c) Recompletion: None, provided bbl meets permit requirements. Drilling a new BHL outside of original drilling unit would require a new permit.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: yes.

Vertical Deviation

1. Regulation requirement: Yes, if well was drilled as an exceptional location, H₂S is expected.
- (a) When is directional survey necessary? Intentional deviations in well or if sum of vertical surveys suggests a non-routine location (see 62c-26.004), or if H₂S is expected.
 - (b) Filing of survey required: Yes.

Casing and Tubing

1. Minimum amount required:
- (a) Surface casing: Yes.
 - (b) Production casing: Yes.
2. Minimum amount of cement required:
- (a) Surface casing: Yes.
 - (b) Production casing: Yes.
 - (c) Setting time: 24 hours. 12 hours under pressure.
3. Tubing requirements:
- (a) Oil wells: Yes. New or like new pipe. Size and weight and A.P.I. specifications of type used.
 - (b) Gas wells: Same as above.

Completion

1. Completion report required: Yes.
- (a) Time Limit: 30 days. Form 8, Well Record, required within 30 days after reaching T.D. Form 9, Well Completion Report, required within 5 days after well test is completed.

- (b) Where submitted: Florida Geological Survey, Tallahassee, FL.
- 2. Well logs required to be filed: Yes.
 - (a) Time limit: 30 days.
 - (b) Where submitted: Florida Geological Survey, Tallahassee, FL.
 - (c) Confidential time period: Yes, one year.
 - (d) Available for public use: Yes, after one year.
 - (e) Log catalog available: No.
- 3. Multiple completion regulation: No.
- 4. Commingling in well bore: No.
 - (a) Approval obtained:

Oil Production

- 1. Definition of an oil well: None.
- 2. Potential tests required: Yes.
 - (a) Time interval: Five days.
 - (b) Witness required: They may be witnessed.
- 3. Statewide allowable: No.
 - (a) Pool allowable: Yes, M.E.R.
 - (b) Well allowable: Yes, M.E.R.
 - (c) Exempt allowable: No.
- 4. Maximum gas-oil ratio: 2,000 cubic feet of gas to 1 Bbl of oil.
 - (a) Provision for limiting gas-oil ratio: Yes. Any well producing more than 2,000 GOR reduced to daily oil allowable x 2,000 divided by GOR.
 - (b) Exception to limiting gas-oil ratio: No.
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: Yes.
- 6. Commingling oil in common facilities: Yes. If field is unitized or meters are utilized prior to commingling.
- 7. Measurement involving meters: Yes.
- 8. Production reports:

- (a) By lease: No.
- (b) By well: Yes.
- (c) Time limit: 30 days from end of month in which production occurred.

Gas Production

1. Definition of a gas well: None.
2. Pressure base 14.65 psia @ 60 degrees F.
3. Initial potential tests: Yes. (No gas wells in Florida.)
 - (a) Time interval: Five days.
 - (b) Witness required: They may be witnessed.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes. Determined from maximum efficient rate (M.E.R.).
 - (b) Well allowable: Same as above.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: Yes.
6. Commingling of gas in common facilities: Yes, after measurement.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: 30 days subsequent to the month of reported production.

Water Disposal

1. State agencies that control disposal of produced salt water: Division of Resource Assessment and Management, Florida Geological Survey.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 75%.

(b) Royalty interest: 75%.

Taxation

Gas severance tax = index tax of 12.5% of MCF

Gas ad valorem tax = 0.0%

Total gas tax burden = 12.5% per MCF

Oil severance tax = 8.0%

Oil ad valorem tax = 0.0%

Total oil tax burden = 8.0%

1. Tax collection agency: Department of Revenue, 5050 W. Tennessee Street, Tallahassee, FL 32399-0100.
2. How tax is computed: Oil severance tax is computed by calculating 8% of the total value produced. Gas severance tax is computed by calculating the index rate (12.5%) times the production measured in MCF. The tax is actually an excise tax, but is commonly referred to as a severance tax.
3. Exemptions or exceptions: Oil and gas used on lease where produced is exempt from tax. Small wells producing less than 100 barrels per day and tertiary oil are taxed at a reduced rate of 5%.
4. Name of tax: The tax is an Excise Tax, but is commonly referred to as a Severance Tax.
5. Statutory citation: Chapter 211.025, and 211.02, Florida Statutes.

Land Leasing Information

1. Leasing Method: Sealed competitive bids.
2. Notice Method: Once a week for at least 4 weeks in some newspaper in the county.
3. Minimum bidding \$ (per acre): \$3.50
4. Qualification of the bidder:
5. State Statutes: §253.53, 54.
6. Maximum acres:
7. Contact: Dr. O. Greg Brock
E-mail: brock_g@epic5.dep.state.fl.us

Division of State Lands, Bureau of Public Land Administration, Department of Environmental Protection.

Naturally Occurring Radioactive Materials (NORM)

1. Regulating Agency: Department of Health, Bureau of Radiation Control, 1317 Winewood Blvd., Tallahassee, FL 32399-0700, Phone: (850) 487-2437, Fax: (850) 921-6364.
2. Relevant Statute/Regulations: Chapter 64E-5, Florida Administrative Code (soon to be reissued as chapter 64E-5, F.A.C.).
3. Scope:
4. Licensing:
5. Cleaning Equipment:

6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State: 30 drums at 55 gallons each.

OTHER:

Florida's oil and gas industry is divided into two regions. In the western Panhandle to the north of Pensacola lies the Jay trend, consisting of eight fields. In south Florida, the Sunniland trend includes 14 fields located to the west and southeast of Ft. Myers. Production in south Florida began in 1943; the Panhandle fields were not discovered until 1970. Production peaked at 47.5 million barrels in 1978 and has been in general decline since then, but both regions are expected to continue operations for many more years. The Jay fields dominate, contributing around 70 percent of total production. Offshore oil production in Florida waters is currently nonexistent due to a ban on exploration and development.

The Department of Health first investigated technologically enhanced naturally occurring radioactive materials (TENORM) contamination in Florida's oil and gas industry in the late 1980s. Exxon Company USA was the state's largest operator at time, for both the Panhandle and south Florida regions. In response to NORM regulations adopted by Louisiana and Texas, Exxon developed corporate guidelines that all of their personnel and contractors follow. The guidelines are designed to ensure compliance with the most stringent NORM regulations, regardless of whether or not the jurisdictions in which they were operating have established NORM regulations. Thus, Exxon and their contractor personnel working in Florida complied with corporate worker protection procedures, and their NORM wastes were properly disposed.

A staff health physicist inspecting Exxon's south Florida fields in 1989 found maximum radiation levels in the 20-30 μ R/hr range at the fields' tank batteries. A recently completed inspection of five of the oldest fields in the same region (now operated by Calmet Florida, Inc.) served to confirm the 1989 results. The highest gamma readings found was 80 μ R/hr in a saltwater storage tank; all other readings ranged from background (10-14 μ R/hr) to 40 μ R/hr, with most in the 20 μ R/hr range. The geochemistry of produced waters in the region does not appear to be conducive to radium replacement, resulting in low activity scale formation. Thirty-eight pipe scale samples were analyzed for radium content, with concentrations ranging from <0.75pCi/g.-11.5pCi/g. with an average of 2.1pCi/g.

The panhandle region was also investigated in the late 1980s, but documentation of the findings is lacking. Records indicate that in 1993, Exxon was approved to dispose of 186 barrels of NORM waste (drilling mud) downhole in a wellbore during plugging and abandonment of one of their exhausted wells. In all other cases, Exxon's NORM wastes were shipped out of state for disposal at licensed waste disposal facilities.

In 1996, staff inspectors visited the two treatment facilities operating in the region, one operated by Exxon, and the other by De Soto Oil and Gas, Inc. (now Petro Operating Co.). The highest external gamma reading (100-200 μ R/hr) were noted in separator tanks, but due to extremely low worker occupancy times in the elevated radiation fields, the readings were not considered an occupational hazard.

De Soto was found to be generating small quantities of NORM waste (approximately 50 drums) and storing them on site pending availability of a wellbore ready for plugging and abandonment, which they planned to use for downhole disposal of their wastes. Exxon no longer operates in the Panhandle region, having recently sold their interests to Louisiana Land Exploration (LL&E).

Due to the low occupancies for the areas where elevated gamma readings were noted, our current position is that oil and gas TENORM in Florida does not warrant increased regulatory oversight at this time. However, additional analysis of data and additional field measurements may lead us to reassess our view, particularly if an effort to promulgate comprehensive TENORM regulations is made.

11. Respondent: Walter Cofer.

GEORGIA

Administration

1. State agency: Environmental Protection Division, Department of Natural Resources, Geologic Survey Branch, Room 400, 19 Martin Luther King Jr. Dr., S. W., Atlanta, GA 30334-9004. Phone (404) 656-3214. (Rules and Regulations are available from the above).
2. Docketing procedure: None; permits are issued or denied within 4 weeks of properly completed applications.
 - (a) Emergency orders: The Director of the Environmental Protection Division may issue emergency orders for safety purposes or to protect ground and/or surface water.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: Well must be plugged according to agreed upon specifications. All information developed from the well must be submitted to the Geologic Survey.
 - (a) Amount per well: Flexible; up to \$50,000.
 - (b) Amount of blanket bond: \$50,000 and adequate documentation of financial resources to plug wells.

Spacing

1. Spacing requirements: Flexible; to insure public safety at well or to maximize production; refer to Rules and Regulations.
 - (a) Density: Flexible.
 - (b) Lineal: Flexible.
2. Exceptions: Yes.
 - (a) Basis: Adequate technical justification.
 - (b) Approval: By the Director of the Environmental Protection Division.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: Yes, from Department of Transportation with concurrence from Geologic Survey.
 - (c) Recompletion: Yes.

- (d) Plugging and abandoning: Yes.
- 2. Permit fee:
 - (a) Drilling: Yes, \$25.
 - (b) Seismic drilling: No.
 - (c) Recompletion: N/A.
 - (d) Plugging and abandoning: N/A.
- 3. Require filing report of work performed: Yes, well completion report.

Vertical Deviation

- 1. Regulation requirement: Flexible; refer to Rules and Regulations.
 - (a) When is directional survey necessary? Flexible.
 - (b) Filing of survey required: Yes.

Casing and Tubing

- 1. Minimum amount required:
 - (a) Surface casing: Yes, to bottom of all fresh water zones.
 - (b) Production casing: N/A.
- 2. Minimum amount of cement required:
 - (a) Surface casing: Yes, entire annular space.
 - (b) Production casing: N/A.
 - (c) Setting time: Not specified.
- 3. Tubing requirements:
 - (a) Oil wells: Not specified.
 - (b) Gas wells: Not specified.

Completion

- 1. Completion report required: Yes.
 - (a) Time limit: 45 days after completion.
 - (b) Where submitted: State Geologist, Georgia Geologic Survey, Room 400, 19 Martin Luther King Dr., S. W., Atlanta, GA 30334.
- 2. Well logs required to be filed: Yes.

- (a) Time limit: 45 days after well completion.
- (b) Where submitted: State Geologist, Georgia Geologic Survey, Room 400, 19 Martin Luther King Dr., S. W., Atlanta, GA 30334.
- (c) Confidential time period: Yes. Six months or longer.
- (d) Available for public use: Yes, after confidential period expires.
- (e) Log catalog available: Yes.
- 3. Multiple completion regulation: Yes.
 - (a) Approval obtained: Yes.
- 4. Commingling in well bore: Yes.
 - (a) Approval obtained: Yes.

Oil Production

- 1. Definition of an oil well: Georgia has no production as yet, so has not legally defined the term "oil well." To qualify for the oil well production bonus, the law requires at least 100 barrels of oil per day production.
- 2. Potential tests required: N/A.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
- 3. Statewide allowable: N/A.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
- 4. Maximum gas-oil ratio: N/A.
 - (a) Provision for limiting gas-oil ratio: N/A.
 - (b) Exception to limiting gas-oil ratio: N/A.
- 5. Bottom-hole pressure test reports required: N/A.
 - (a) Periodical bottom-hole pressure surveys: N/A.
- 6. Commingling oil in common facilities: N/A.
- 7. Measurement involving meters: N/A.
- 8. Production reports: N/A.
 - (a) By lease:

- (b) By well:
- (c) Time limit:

Gas Production

1. Definition of a gas well: Georgia has no production as yet, so has not legally defined the term "gas well".
2. Pressure base N/A psia @ _____ degrees F.
3. Initial potential tests: N/A.
 - (a) Time interval:
 - (b) Witness required:
4. Statewide allowable: N/A.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
5. Bottom-hole pressure test reports required: N/A.
 - (a) Periodical bottom-hole pressure surveys:
6. Commingling of gas in common facilities: N/A.
7. Measurement involving meters: N/A.
8. Production reports: N/A.
 - (a) By lease: N/A.
 - (b) By well:
 - (c) Time limit:

Water Disposal

1. State agencies that control disposal of produced salt water: Environmental Protection Division; Water Protection Branch.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: N/A at present; but rules and regulations provide for compulsory unitization.

Taxation

There is no state tax levied on oil and gas production in Georgia.

Land Leasing Information

1. Leasing Method: Sealed competitive bids.
2. Notice Method: Once a week for 2 consecutive weeks in the legal organ and in one or more newspapers in the county or counties.
3. Minimum bidding \$ (per acre):
4. Qualification of the bidder:
5. State Statutes: §50-16-43
6. Maximum acres:
7. Contact: Tony McCook
Phone: (404) 656-6328
E-mail: tony_mccook@mail.dnr.state.ga.us

Naturally Occurring Radioactive Material (NORM)

No regulations at this time.

IDAHO

Administration

1. State agency: Oil and Gas Conservation Commission, Idaho Department of Lands, 954 W. Jefferson, P O Box 83720, Boise, Idaho 83720. Telephone (208) 334-0231.
2. Docketing procedure: Proper application to be filed in accord with the "Rules of Practice and Procedure" accompanied by an application fee of \$100. A hearing date will be set by the Commission as soon as feasible and notice thereof given. Commission shall enter its order within 30 days following the hearing.
 - (a) Emergency orders: Section 47-324, Idaho Code. Situation causing order must require immediate action. Order will be effective up to 15 days from promulgation.
 - (b) Notice: Section 47-324, Idaho Code. Ten days. Notice published by the Commission.

Bond

1. Compliance bond required: Yes. Form P-2.
2. Conditions of bond: Conditioned upon the performance of the operator's duty to comply with the requirements of the Conservation Act and Rules. Released when plugging of well is approved by the Commission.
 - (a) Amount per well: \$10,000.
 - (b) Amount of blanket bond: \$25,000.

Spacing

1. Spacing requirements: Yes. General rules are automatic. (Rule 33.)
 - (a) Density: Generally, every well drilled for oil must be located on a drilling unit consisting of approximately 40 contiguous surface acres contained within the bounds of one governmental quarter-quarter sections or lots having one side in common, and being within one governmental quarter section upon which no part is attributed to another well completed or drilling to the same pool. In addition, said drilling unit will not have a side in common with another quarter-quarter section or lot upon which there is a well completed to or drilling to the same pool.

Generally, every well drilled for gas must be located on a drilling unit consisting of approximately 640 contiguous surface acres, which will be one governmental section or lots equivalent thereto, upon which no part is attributed to another well completed or drilling to the same pool.
 - (b) Lineal: Wells drilled for oil will not be located closer than 500 feet to any boundary of the unit, and not farther than 500 feet from the shortest center line of the unit.

Each well drilled for gas will be located within a square, each side to be 1,660 feet long and parallel to a center line of the section, and the center to coincide with the center of the section.
2. Exceptions: Yes. Section 47-321, Idaho Code.
 - (a) Basis: If well would likely be non-productive, or surface conditions will create excessive hazards or cost, or other good cause shown by applicant.
 - (b) Approval: Application to be filed with Commission. Must show reason for exception request, and show consent by the owners of all drilling units (established or projected) directly or diagonally offsetting the drilling unit involved with the exception. Section 47-321(d), Idaho Code.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes.
 - (b) Seismic drilling? Yes.
 - (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes.
2. Permit fee:
 - (a) Drilling: \$100.
 - (b) Seismic drilling: No.
 - (c) Recompletion: No.
 - (d) Plugging and abandoning: No.
3. Require filing report of work performed: Yes. Rule 35, Form P-7 and P-15.

Vertical Deviation

1. Regulation requirement: Yes. Rule 17.
 - (a) When is directional survey necessary? Drilling would be by special application under the Rules. Surveys would be required as necessary to insure well direction reasonably agrees with the plan as approved.
 - (b) Filing of survey required? Yes, upon completion.

Casing and Tubing

1. Minimum amount required: Rule 8.
 - (a) Surface casing: Yes. Surface casing to be set to a depth below all known and encountered fresh water aquifers, sufficiently deep to prevent blow-outs, and set through an impervious casing.
 - (b) Production casing: Casing program must be sufficient to prevent migration between horizons, and infiltration of injurious waters from other sources.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes. Cemented to the surface.
 - (b) Production casing: Yes. Degree of cementing depends upon well and field conditions.

- (c) Setting time: Yes, 8 hours.
- 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

- 1. Completion report required: Yes. Rule 9.
 - (a) Time limit: 30 days after completion.
 - (b) Where submitted: Sent to office of Commission.
- 2. Well logs required to be filed: Yes. Section 47-319, Idaho Code, Rule 9.
 - (a) Time limit: 30 days after completion.
 - (b) Where submitted: Office of the Commission.
 - (c) Confidential time period: Yes, upon request of operator. One year.
 - (d) Available for public use: All logs available to public, unless held confidential, in which case open to public following expiration of confidentiality period.
 - (e) Log catalog available: Yes, but very general and not published.
- 3. Multiple completion regulation: Yes. Rule 21.
 - (a) Approval obtained: Application to the Commission.
- 4. Commingling in well bore: Yes. Rule 22.
 - (a) Approval obtained: Application to the Commission.

Oil Production

- 1. Definition of an oil well: Rule 3. Oil well for the purposes of the Rules means any well capable of producing oil in paying quantities.
- 2. Potential tests required: Yes. Rule 9.
 - (a) Time interval: 30 days.
 - (b) Witness required: No.
- 3. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.

4. Maximum gas-oil ratio: 2,000 cubic feet per barrel of oil production. Rule 28, 2.9.
 - (a) Provision for limiting gas-oil ratio: Yes. Issuance of emergency order temporarily prohibiting continued production.
 - (b) Exception to limiting gas-oil ratio: Yes. Through hearing process.
5. Bottom-hole pressure test reports required: Yes. Rule 9. Form P-7.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: Has authority, but no regulation promulgated to date. Section 47-319, Idaho Code.
7. Measurement involving meters: Yes. Rule 26.
8. Production reports: Rule 35. Commission has the authority. Specific requirements to be established with start of production.
 - (a) By lease:
 - (b) By well:
 - (c) Time limit:

Gas Production

1. Definition of a gas well: Rule 3. Gas well shall mean (a) a well which produces natural gas only; (b) any well capable of producing gas in commercial quantities and also producing oil from the same common source but not in commercial quantities; or (c) any well classed as a gas well by the Commission for any reason.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes. Rule 9.
 - (a) Time interval: 30 days.
 - (b) Witness required: No.
4. Statewide allowable:
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Yes. Rule 9. Form P-7.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: Has authority, but no regulations promulgated to date. Section 47-319, Idaho Code.
7. Measurement involving meters: Yes. Rule 27.

8. Production reports: Rule 35. Commission has the authority. Specific requirements to be established with start of production.
 - (a) By lease:
 - (b) By well:
 - (c) Time limit:

Water Disposal

1. State agencies that control disposal of produced salt water: Oil and Gas Conservation Commission, Idaho Department of Lands.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: No.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization: N/A.
 - (a) Working interest:
 - (b) Royalty interest:

Taxation

Gas severance tax = 2.0%
 Gas ad valorem tax = 0.0%
 Total gas tax burden = 2.0%

Oil severance tax = 2.0%
 Oil ad valorem tax = 0.0%
 Total oil tax burden = 2.0%

1. Tax collecting agency: State Tax Commission, P.O. Box 36, Boise, ID 83722.
2. How tax is computed: The oil and gas severance tax rate is computed as 2.0% of the total value. At this time, Idaho does not have any producing wells and no tax is being collected.
3. Exemptions or exceptions: There are no exemptions or exceptions for gas tax in Idaho.
4. Name of tax: Severance.
5. Statutory citation: 47-330, 47-331, and 47-332 Idaho Code.

Land Leasing Information

1. Leasing Method: Competitive bidding at an oral auction.
2. Notice Method: No less than 30 days prior to the date of the auction in 2 newspaper of general circulation in Idaho and in one or more major trade journals of the department's choice.
3. Minimum bidding \$ (per acre): \$0.25 bonus.

4. Qualification of the bidder: Any person defined under IDAPA 20-03-16 §010-15, §020.
5. State Statutes: IDAPA 20-03-16 §§ 010-15, 015, 016, 020, 022, 023, 025, 026, 027, 028.
6. Maximum acres: 640 acres.
7. Contact: Sharon A. Murray. Minerals Program Manager, Idaho department of Lands, 954 W. Jefferson, P. O. Box 83720, Boise, Idaho 83720. telephone (208) 334-0231.

Naturally Occurring Radioactive Material (NORM)

No NORM regulations at this time.

ILLINOIS

Administration

1. State agency: Department of Natural Resources, Office of Mines and Minerals, Division of Oil and Gas, One Natural Resources Way, Springfield, IL 62702-1271. Phone (217) 782-7756.
2. Docketing procedure: Upon receipt of proper application, the Department shall promptly fix a date for hearing and cause notice of the hearing to be given.
 - (a) Emergency orders: Yes, for a period of 30 days or until a hearing is held.
 - (b) Notice: Notice of hearings will be published at least ten days prior to date of hearing by the Department.

Bond

1. Compliance bond required: Only for operators on record with the Department for less than two years. No bond required after that period.
2. Conditions of bond: Proper plugging and restoration of well-site on abandonment.
 - (a) Amount per well: \$1,500 less than 2,000 feet.
\$3,000 over 2,000 feet.
 - (b) Amount of blanket bond:

0 - 25 wells	\$ 25,000
26 - 50 wells	\$ 50,000
51 or more wells	\$100,000

Spacing

1. Spacing requirements:
 - (a) Density: Oil - 10 acres for an oil well in a sandstone, 20 acres for an oil well in limestone, 40 acres for an oil well deeper than 4,000 feet. Gas - 10 acres for a gas well in a sandstone, 20 acres for a gas well in a limestone, 40 acres over 2,000 feet but less than 5,000 feet, 160 acres over 5,000 feet for discovery well, offset well spacing set by hearing.
 - (b) Lineal: For an oil or gas well not less than 330 feet from the nearest external boundary lines of the drilling unit.
2. Exceptions: Yes.
 - (a) Basis: Topographical conditions, irregular section, secondary recovery operations, location over mine, or geological conditions.
 - (b) Approval: Administratively after verification of submitted information or by hearing depending on basis stated above.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: No.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes, if well drilled deeper or converted for use other than originally permitted.
 - (d) Plugging and abandoning: No.
2. Permit fee:
 - (a) Drilling: \$100.
 - (b) Seismic drilling: No.
 - (c) Recompletion: \$100, if well drilled deeper or converted for use other than originally permitted.
 - (d) Plugging and abandoning: No.
3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulations requirement: Yes.
 - (a) When is directional survey necessary? A proposed vertical deviation filed with permit application with actual survey required to be filed after well drilled.
 - (b) Filing of survey required: Yes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes, depth based on local conditions.
 - (b) Production casing: Yes, set no higher than 50 feet above the top of the uppermost producing interval.
2. Minimum amount of cement required:
 - (a) Surface casing: Circulated to surface.
 - (b) Production casing: yes, minimum of 250 feet above producing interval.
 - (c) Setting time: yes, minimum of four hours for surface casing before commencing drilling. No requirements for production casing.
3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes.
 - (a) Time limit: Within 30 days of completion of well.
 - (b) Where submitted: Department of Natural Resources, Division of Oil and Gas, One Natural Resources Way, Springfield, IL 62702-1271.
2. Well logs required to be filed: Yes.
 - (a) Time limit: Within 90 days after drilling ceases.
 - (b) Where submitted: State Geological Survey, Natural Resources Building, 615 East Peabody Drive, Champaign, IL 61820.
 - (c) Confidential time period: Yes, if requested. Two years from date of permit.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
3. Multiple completion regulation: No, unless wellspacing affected by multiple zones.
 - (a) Approval obtained: Authorization obtained during permit process, amendment for later completions required only if spacing affected.
4. Commingling in well bore: Allowable, no authorization required.
 - (a) Approval obtained: None required.

Oil Production

1. Definition of an oil well: "Oil Well" shall mean any well drilled for the production of oil.
2. Potential tests required: No.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
3. Statewide allowable: No.
 - (a) Pool allowable: N/A.
 - (b) Well allowable: N/A.
 - (c) Exempt allowable: N/A.
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: N/A.
 - (b) Exception to limiting gas-oil ratio: N/A.

5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: N/A.
6. Commingling oil in common facilities: No.
7. Measurement involving meters: No.
8. Production reports: No.
 - (a) By lease: N/A.
 - (b) By well: N/A.
 - (c) Time limit: N/A.

Gas Production

1. Definition of a gas well: "Gas Well" means a well with a gas to oil production ratio equal to or greater than 10,000 cubic feet of gas to one barrel of oil.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: No.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
4. Statewide allowable: No.
 - (a) Pool allowable: N/A.
 - (b) Well allowable: N/A.
 - (c) Exempt allowable: N/A.
5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: N/A.
6. Commingling of gas in common facilities: No.
7. Measurement involving meters: No.
8. Production reports: No.
 - (a) By lease: N/A.
 - (b) By well: N/A.
 - (c) Time limit: N/A.

Water Disposal

1. State agencies that control disposal of produced salt water: Department of Natural Resources, Office of Mines and Minerals, Division of Oil and Gas.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: No.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 51%
 - (b) Royalty interest: 51%

Taxation

1. There is no state severance tax levied on oil and gas in Illinois. There are county ad valorem taxes.

Land Leasing Information

1. Leasing Method: Sealed competitive bids on lands designated by state. State may reject all bids. Drilling on lands owned by Department of Natural Resources is prohibited.
2. Notice Method: Public notice by publication in newspaper or other publications with statewide distribution and notice given to persons on department maintained lease notice list.
3. Minimum bidding \$ (per acre): Minimum acceptable royalty rate – no less than 12 ½ % per centrum. Minimum bonuses in addition to the set royalty provision established at time of bid solicitation.
4. Qualification of bidder: Post bond and have no outstanding violations of Oil and Gas Act.
5. State Statutes: Oil and Gas Wells on Public Lands Act 5 ILCS 615/1 et. seq.
6. Maximum acres: Variable, to be determined at time of bid solicitation.
7. Contact: Duane Pulliam, interim Division Manager
Phone: (217) 782-7756
E-mail: duane.pulliam@illinois.gov

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Natural Resources, Division of Oil and Gas, One Natural Resources Way, Springfield, IL 62702-1271, Phone: (217) 782-7756, Fax: (217) 524-4819, E-mail: duane.pulliam@illinois.gov
Relevant Statute/Regulations: Illinois Oil and Gas Act – 225 ILCS 725/1.
3. Scope: Department has authority to regulate all oil and gas wastes. Does not name NORM specifically, but Department interprets all to include oilfield NORM.
4. Licensing: None required at this time. State Department of Nuclear Safety may purpose NORM regulations; however, current state low-level waste statutes implemented by Nuclear Safety are not clear on NORM authority.
5. Cleaning Equipment: None regulated at this time except from the standpoint of worker safety which is under the

- jurisdiction of the Department of Nuclear Safety.
6. Disposal of Waste: Currently, only disposal of NORM in pit residues are regulated.
 7. Subsequent Use of Equipment: Equipment not regulated at this time.
 8. Subsequent Use of Materials: Use of potentially NORM contaminated materials are not regulated at this time.
 9. Released/Sale of NORM-Contaminated Land: Current regulations only require a notice be filled with the County Clerk stating the presence of NORM at a closed pit site.
 10. Projected Volume of stored NORM in the State: Unknown.
 11. Respondent:
 12. Regulating Agency: Illinois Department of Nuclear Safety, Division of Materials, 1035 Outer Park Drive, IL 62704, Phone: (217) 785-9935, Fax: (217) 782-1328.
 13. Relevant Statute/Regulations: 32 Illinois Administrative Codes, but currently developing a specific TENORM rule.
 14. Scope: Covers all radioactive material and facilities that are not areas of exclusive federal jurisdiction.
 15. Licensing: Required for all that are not exempt.
 16. Cleaning Equipment: License required.
 17. Disposal of Waste: To specifically approved facilities and by specifically approved methods only.
 18. Subsequent Use of Equipment: Okay.
 19. Subsequent Use of Materials: Case-by-case evaluation needed.
 20. Release/Sale of NORM-Contaminated Land: Case-by-case evaluation. Decommissioning generally required.
 21. Projected Volume of stored NORM in the State: Unknown.
 22. Respondent: Steven Collins.

INDIANA

Administration

1. State agency: Division of Oil and Gas, 402 West Washington Street, Room W293, Indianapolis, IN 46204. Phone (317) 232-4055.
2. Docketing procedure: Upon receipt of a petition concerning a matter within the jurisdiction of the Department, the hearing date will be fixed and notice will be given.
 - (a) Emergency orders: There is authority under the law to issue an emergency order, by the Director of the Department of Natural Resources.
 - (b) Notice: Fifteen days by the Department.

Bond

1. Compliance bond required: Yes. Except for exemption provided for by statute. Operators may submit annual well fee in lieu of bond.
2. Conditions of bond: Restoration of surface to its former condition and plugging of well.
 - (a) Amount per well: \$2,500.
 - (b) Amount of blanket bond: \$45,000.

Spacing

1. Spacing requirements: Yes.
 - (a) Density: Oil well - 10 acres for sandstone and 20 acres for all other reservoirs except wells in the established Trenton formation which allow 5 acre spacing. Gas well - above 1,000 feet same as above; below 1,000 feet, 40 acres.
 - (b) Lineal: Oil well - 330 feet from a property or unit line; 660 feet from another well producing from the same formation. Gas well - above 1,000 feet same as oil; below 1,000 feet, 330 feet from a property or unit line and 1,320 feet from another well. Non Commercial Gas well - no spacing or unit requirements. Established Trenton field wells 165 feet from property or unit line.
2. Exceptions: Yes.
 - (a) Basis: When geological and pool conditions justify.
 - (b) Approval: By hearing.

However, public notice is required prior to permit issuance.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:

- (a) Drilling an operating, service well or test hole: Yes.
- (b) Seismic drilling? Yes.
- (c) Recompletion? No.
- (d) Plugging and abandoning? No.

2. Permit fee:

- (a) Drilling: \$250 + \$500 for expedited processing (if requested).
- (b) Seismic drilling: N/A
- (c) Recompletion: None.
- (d) Plugging and abandoning: None.
- (e) Annual fee for each Class II well: None.
- (f) Annual fee for existing permitted wells: Yes.

<u>Number of Wells</u>	<u>Amount</u>
1 well	\$150
2-5 wells	\$300
6-25 wells	\$750
26-100 wells	\$1,500
>100 wells	\$1,500 plus \$15 for each well over 100

NOTE: The Division of Oil and Gas will send a notice to operators before December 1 of each year listing the wells permitted to the operator as of November 1 of that year.

3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: No.

- (a) When is directional survey necessary? When the operator drills a directional hole.
- (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:

- (a) Surface casing: Yes - below all fresh water, except where production casing cemented to surface.
- (b) Production casing: Yes, to top of last stratum drilled.

2. Minimum amount of cement required:

- (a) Surface casing: To surface, except as noted in 1. above.
- (b) Production casing: Yes, to bottom of last string run and/or cemented to surface.

- (c) Setting time: Upon completion of drilling.
- 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.
 - (c) Class II wells: Yes.

Completion

- 1. Completion report required: Yes.
 - (a) Time limit: Within 30 days of completion of the well.
 - (b) Where submitted: Division of Oil and Gas, 402 West Washington Street, Room 293, Indianapolis, IN 46204.
 - (c) Confidential time period: Yes. If requested, one year from date of completion.
- 2. Well logs required to be filed: Yes, if run. Three copies of each log run.
 - (a) Time limit: Within 30 days of date run.
 - (b) Where submitted: Division of Oil and Gas, 402 West Washington Street, Room 293, Indianapolis, IN 46204.
 - (c) Confidential time period: Yes. If requested, one year from date of completion.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
- 3. Multiple completion regulation: No.
 - (a) Approval obtained:
- 4. Commingling in well bore: No.
 - (a) Approval obtained.

Oil Production

- 1. Definition of an oil well: Statutes or regulations do not define oil well. (However, "oil" means all liquid petroleum produced at a well.)
- 2. Potential tests required: No.
 - (a) Time interval:
 - (b) Witness required:
- 3. Statewide allowable: No.
 - (a) Pool allowable:
 - (b) Well allowable:

- (c) Exempt allowable:
- 4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: No.
 - (b) Exception to limiting gas-oil ratio: No.
- 5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: No.
- 7. Measurement involving meters: No.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: No.
 - (c) Time limit:

Gas Production

- 1. Definition of a gas well: Statutes or regulations do not define a gas well. ("Gas" means natural gas.)
- 2. Pressure base _____ psia @ ____ degrees F.
- 3. Initial potential tests: No.
 - (a) Time interval:
 - (b) Witness required:
- 4. Statewide allowable: No.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
- 5. Bottom-hole pressure tests reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: No.
- 7. Measurement involving meters: No.
- 8. Production reports:

- (a) By lease: No.
- (b) By well: No.
- (c) Time limit:

Water Disposal

1. State agencies that control disposal of produced salt water: Division of Oil and Gas, 402 West Washington Street, Room 293, Indianapolis, IN 46204.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization: No.
 - (a) Working interest:
 - (b) Royalty interest:

Taxation

Gas severance tax = 1.0% of value at the time the gas is severed, or \$0.03 per MCF; whichever is greater.

Gas ad valorem tax = 0.0%

Total gas tax burden = 1.0% or \$0.03 per MCF; whichever is greater

Oil severance tax = 1.0% of value at the time the oil is severed, or \$0.24 per barrel; whichever is greater.

Oil ad valorem tax = 0.0%

Total oil tax burden = 1.0% or \$0.24 per barrel; whichever is greater

1. Tax collecting agency: Special Tax Division, Department of Revenue, N248 State Office Building, 100 N. Senate, Indianapolis, IN 46204.
2. How tax is computed: Gas severance tax is computed as 1% of the value at the time the gas is severed or \$0.03 per MCF, whichever is greater. Oil severance tax is computed as 1% of the value at the time the oil is severed or \$0.24 per barrel, whichever is greater.
3. Exemptions or exceptions: None.
4. Name of tax: Petroleum Severance Tax.
5. Statutory citation: IC 6-8-1.

Land Leasing Information

1. Leasing Method: Sealed bids, but may offer competitive public bidding.
2. Notice Method:
3. Minimum bidding \$ (per acre): Set a minimum acceptable royalty rate, which may not be less than 12 1/2% and call for competitive offers by prospective lessees for cash bonuses in addition to the set royalty provision.
4. Qualification of the bidder:

5. State Statutes: IC 14-38-1-11
IC 14-38-1-12
IC 14-38-1-14
IC 14-38-1-16
6. Maximum acres: 3 sections or an equivalent area.
7. Contact: Herschel McDivitt, Director
Phone: (317) 232-4058
E-mail: hmcdivitt@dnr.in.gov

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: State Department of Health, Emergency Response and Radioactive Material Programs, Indoor and Radiologic Health, 2 North Meridian St., 5th Floor, Indianapolis, IN 46204-3003. Phone: (317) 233-7153, Fax: (317) 233-7154.
2. Relevant Statute/Regulations: Proposed - No state regulations for dealing with NORM in the oil and gas industry.
3. Scope: When found in scrap streams our office provides list of radiation brokers (CRCPD).
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Respondent: Herschel McDivitt

KANSAS

Administration

1. State Agency: State Corporation Commission, Conservation Division, Finney State Office Building, 130 S. Market, Room 2078, Wichita, KS 67202. Phone (316) 337-6200.
2. Docketing procedure: Hearings generally held on the third Thursday of each month. Applications must be received at least 30 days prior to date of hearing. Six month schedules available from the Conservation Division.
 - (a) Emergency orders: Yes, emergency action may be taken by the Commission without notice and hearing, such action to remain in force no longer than 30 days from the effective date. K.S.A. 55-605.
 - (b) Notice: At least 10 days prior to hearing. Kansas Corporation Commission, Conservation Division. K.S.A. 55-605 and K.A.R. 82-3-135.

License

1. License required: Yes, for every well operator, drilling, plugging contractor, including Cathodic protection bore holes and seismic drilling contractors and gas gathering system operators. Additionally, operators of gas gathering systems, facilities including all underground gas porosity storage wells and facilities must be licensed. K.S.A. 55-150, 55-155. Operators of a single residential gas well for home heating have a reduced license fee.
2. Conditions of license: Filing of a verified application, certificate of good standing from Secretary of State if applicable and payment of proper fees. K.A.R. 82-3-120; 82-3-121.

Bond

1. Compliance bond required: Yes. A bond or other financial assurance is required. K.A.R. 82-3-120.
2. Conditions of bond: Operator's must have an acceptable 3 (three) year past record of compliance. For operators that DO NOT meet this criteria they must post a performance bond or other means of financial assurance.
 - (a) Amount per well: .75¢ times the aggregate depth for all wells drilled or operated.
 - (b) Amount of blanket bond: Ranges from \$7,500 to \$45,000 depending on the number of wells and depth.

Spacing

1. Spacing requirements: Yes. K.A.R. 82-3-108 and 82-3-312.
 - (a) Density: 10 acres for oil and gas wells.
 - (b) Lineal: Gas and oil wells shall be located 330' or more from any lease or unit boundary line to qualify for a full allowable. K.A.R. 82-3-207 and 82-3-312.
2. Exceptions: Yes. Oil wells drilled to a depth of less than 2,000 feet in certain counties in eastern Kansas have a lineal distance requirement of 165 feet from the nearest lease or unit boundary line. K.A.R. 82-3-108(b.) Other exceptions to spacing requirements maybe granted by Commission order after notice of the application and possible hearing.
 - (a) Basis: Application by operator.
 - (b) Approval: Commission order. Hearing if needed after notice. K.A.R. 82-3-108.

Pooling

1. Authority to establish voluntary: Yes. Terms of contract (lease).
2. Authority to establish compulsory: No.

Drilling Permit

1. Require permits for:
 - (a) Drilling a oil, gas, re-entry workover, service, cathodic borehole or gas storage well? Yes, K.A.R. 82-3-701 et seq. Statutory authority under K.S.A. 55-151. Required prior KCC Intent to Drill permit approval and operators are required to post approved permit on location with the drilling rig during drilling operations.
 - (b) Notification: Verbal notice of drilling commencement required to District offices.
 - (c) Seismic drilling: Yes, K.A.R. 82-3-115a.
 - (d) Recompletion: No, but completion report (ACO-1 Form) is required: K.A.R. 82-3-103. Notice to the appropriate KCC district office must be made at least 48 hours prior to the commencement of recompletion with prior work over pit authorization and approval. K.A.R. 82-3-132.
 - (e) Plugging and abandoning: Yes, K.A.R. 82-3-113 and 114. Also reentry of plugged and abandoned wells. K.A.R. 82-3-103. Re-entry notification under K.A.R. 82-3-132.
2. Permit fee:
 - (a) Drilling: None.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: \$.0325 per foot total depth. Min. \$35. K.A.R. 82-3-118. Seismic generally \$1-\$5 depending on depth of shot hole.
3. Require filing report (ACO-1 Form) of work performed: Yes, K.A.R. 82-3-130. Must be filed within 120 days of commencement of drilling operations.

Vertical Deviation

1. Regulation requirement: Yes, K.A.R. 82-3-103a.
 - (a) When is directional survey necessary? Any hole that deviates (including horizontal) greater than 7° from vertical, and/or when requested by Corporation Commission through hearing or per requirements.
 - (b) Filing of survey required: Yes, K.A.R. 82-3-128, 82-3-107, and 82-3-130 (ACO-1 Form).

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes, K.A.R. 82-3-106 and by special order of the Commission. Table 1 for minimum depth. Protect through all unconsolidated material - for Protection of all fresh/usable groundwater.

- (b) Production casing: No. K.A.R. 82-3-105 requires that casing must seal off and isolate producing and water bearing zones, by being cemented in place. Must use a Portland Blend cement.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes, K.A.R. 82-3-106. Table I for minimum depths. Cement metallic casing to surface. Includes Cathodic protection bore holes surface casing pursuant to K.A.R. 82-3-702.
 - (b) Production casing: No. Unless depth of surface casing set does not meet Table I requirement. K.A.R. 82-3-105 requires that metallic casing must seal off and isolate producing and water bearing zones, by being cemented in place. Cathodic bore holes surface casing must be centralized and cemented or grouted in place to the surface pursuant to K.A.R. 82-3-702.
 - (c) Setting time: Yes, 8 hours. K.A.R. 82-3-106 (d) (4). Portland cement and blends K.A.R. 82-3-106(2) (A). Or as per grout manufacture's specifications for cathodic boreholes in K.S.A. 82-3-702.
 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No, except for certain gas storage wells.

Completion

1. Completion report required: Yes (ACO-1 Form).
 - (a) Time limit: Within 120 days from spud date. K.A.R. 82-3-130.
 - (b) Where submitted: Conservation Division.
2. Well logs required to be filed: Yes, all wireline electric logs (including geological report, Core data, DST's, and cement tickets).
 - (a) Time limit: Within 120 days of spud date. K.A.R. 82-3-130.
 - (b) Where submitted: Conservation Division.
 - (c) Confidential time period: Within 120 days of spud date by letter request. One year from date of letter request and may be extended one year by additional letter request. K.A.R. 82-3-107.
 - (d) Available for public use: Unless confidentiality requested, all logs are repositied with the Kansas Geological Survey.
 - (e) Log catalog available: Not at Kansas Corporation Commission. However, is available at Kansas Geological Survey.
3. Multiple completions regulation: Yes, K.A.R. 82-3-124.
 - (a) Approval obtained: by application. Hearing if needed after notice.
4. Commingling in well bore: Yes, K.A.R. 82-3-123.
 - (a) After Approval obtained: by application. Hearing if needed after notice.

Oil Production

1. Definition of an oil well: "Oil well" means a well that produced one stock tank barrel or more of crude oil to each 15,000 standard cubic feet of gas, as measured by the gas-oil ratio test prescribed by and reported on the form prescribed and furnished by the Commission.
2. Potential tests required: Yes.
 - (a) Time interval: In prorated pools productivity tests within 30 days of filing (ACO-1) completion report. K.A.R. 82-3-202.
 - (b) Witness required: Yes, by state representative. Representative of offset operator(s) optional. K.A.R. 82-3-202.
3. Statewide allowable: Yes. As provided for by K.A.R. 82-3-203. Per well allowable is 100, 200, 300 BOPD depending upon depth.
 - (a) Pool allowable: Yes. As provided for by K.A.R. 82-3-203 and by special proration orders.
 - (b) Well allowable: Yes. As provided for by K.A.R. 82-3-203 and by special proration orders.
 - (c) Discovery allowable: No.
4. Maximum gas-oil ratio: Yes, 15 mcf/1 BO.
 - (a) Special individual field rules provide for limiting oil production from high GOR wells.
5. Bottom-hole pressure test reports required: Not required unless by special order. Drill stem pressure tests are reported per ACO-1. K.A.R. 82-3-130, 82-3-107.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: Yes. The production from one or more common source of supply may be commingled before delivery to a purchaser. K.A.R. 82-3-125.
7. Measurement involving meters: Yes, including electronic measurement devices.
8. Production reports: Only prorated pools. K.A.R. 82-3-204. Filed to KCC office.

Oil

- (a) By lease: Yes, if only one well; All others by individual well broken down from common tank. File form CO8A monthly.
- (b) By well: Yes, by meter or gauges reading.
- (c) Time limit: By 15th of succeeding month to the Conservation division. K.A.R. 82-3-204.
- (d) All prorated and non-prorated wells report production by lease through first purchaser to the Department of Revenue, Mineral Tax Division.

Gas Production

1. Definition of a gas well: "Gas well" means a well that:
 - (a) Produces gas not associated with oil at the time of production from that reservoir; or

- (b) Produces more than 15,000 standard cubic feet of gas to each stock tank barrel of oil from the same common source of supply, as measured by the gas-oil ratio test prescribed by and reported on the form prescribed and furnished by the Commission.
- 2. Pressure base 14.65 psia @ 60 degrees F.
- 3. Initial potential tests: Yes. K.A.R. 82-3-303 and 82-3-304.
 - (a) Time interval: 30 days for multipoint tests; 30 days for initial one-point stabilized flow tests. Must be submitted to Kansas Corporation Commission 30 days after the test. Test may not be required for wells producing less than 250 mcf per day by "minimum well" exemption. For such "minimum wells" an annual shut-in pressure must be submitted with the request for testing exemption.
 - (b) Witness required: Yes.
- 4. Statewide allowable: Yes. K.A.R. 82-3-312. 50% of calculated open flow with a 250 Mcfd minimum.
 - (a) Pool allowable: Yes. Allocation based primarily on basis of proration of market demand. K.S.A. 55-703.
 - (b) Well allowable: Yes. Individual field basic proration orders set out allocation formulas for gas wells.
 - (c) Exempt allowable: No. However, certain field rules include provisions for minimum allowables. There is also a statewide minimum allowable, for wells not located in specially designated pools. K.A.R. 82-3-312.
- 5. Bottom-hole pressure test reports required: No, unless common mineral and working interest ownership may allow for commingling. K.A.R. 82-3-305.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: No.
- 7. Measurement involving meters: Yes. K.A.R. 82-3-305 is the general rule, electronic gas measurement and measurement with a turbine meter is allowed and can be used in deliverability testing in certain prorated fields.
- 8. Production reports: Gas production is reported monthly by operators. K.A.R. 82-3-306.
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limit: Monthly. K.A.R. 82-3-306.

Water Disposal

- 1. State agencies that control disposal of produced salt water: The Kansas Corporation Commission controls disposal of produced water. K.A.R. 82-3-400 et seq.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source of supply. Yes. K.S.A. 55-1301-1315.
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Unitization for enhanced recovery operations
 - (1) Working Interest: 63%

- (2) Royalty Interests (excluding overriding royalties): 63%
- (b) Unitization for management purposes
 - (1) Working Interest: 63%
 - (2) Royalty Interests (excluding overriding royalties): 75%

Taxation

Gas severance tax = 4.33%

Gas ad valorem tax = varies by county; approximately 10% of revenue

Total gas tax burden = approximately 15-17% of revenue

Oil severance tax = 4.33%

Oil ad valorem tax = varies by county; approximately 4% of revenue

Total oil tax burden = approximately 8% of revenue

1. Tax collecting agency: Department of Revenue. The Department of Revenue also collects the Kansas Corporation Commission Conservation Division fees which are currently 12.90 mills/MCF of produced gas, and 91.00 mills per barrel of oil.
2. How severance tax is computed: Gas severance is 8%, with a 3.67% credit for ad valorem tax, which is a net severance tax of 4.33%. The ad valorem tax is premised on market value of the lease as developed by applying the *Oil and Gas Guide* issued annually by the Kansas Department of Revenue, Division of Property Valuation. It is administered by county government and collected by them for use at the county level. A credit of 15 and 17% is given as expense allowance in the valuation of the gas lease for the expense of severance and ad valorem taxes. The 15% is applicable to the Hugoton Field and the 17% is applicable to all other gas producing properties.

Oil severance tax is 8% with a 3.67% credit for ad valorem taxes, which is a net severance tax of 4.33%. Oil lease ad valorem tax is generally 4% of revenues, hence the 3.67% credit for severance. The oil lease ad valorem tax is administered the same as the gas ad valorem tax.

Ad valorem values may vary widely year to year depending on price and production. In 1999 the price used for oil was \$8.75, in 2000 the price increased to \$19 and the valuation statewide doubled.

3. Exemptions or exceptions: The production of gas which is: (A) Injected for the purpose of lifting oil; (B) used for fuel on the lease; (C) lawfully vented or flared; (D) severed from a well having an average daily production with a gross value of not more than \$87 per day; (E) inadvertently lost by reason of accidental losses; (F) used for domestic or agricultural purposes on the lease; (G) placed in underground storage and which was severed from another state or the tax had been previously paid if severed in Kansas.

The severance and production of oil which is: (A) From a lease or production unit whose average daily production from a producing well, or from all producing wells is five barrels or less; (B) from producing wells which have a depth of 2,000 feet or more, and whose average daily production is six barrels or less (C) from a lease or production unit, whose production results from a tertiary recovery process; (D) from wells which have a completion depth of less than 2,000 feet and whose average daily production, from water flood, is six (6) barrels or less; (E) from wells which have a completion depth of 2,000 feet or more, and whose average daily production from a waterflood process, is seven barrels or less (F) test, frac or swab oil exchanged for value; (G) inadvertently lost by accidental means.

All oil leases, other than royalty interest therein, that have an average daily production of five barrels or less per producing well, or six barrels or less per producing well, which has a completion depth of 2,000 feet or more, are exempt from the severance tax under current law. Add one barrel if the well is a waterflood.

The production of oil or gas from a pool that was first produced after April 12, 1983 (new pool) is exempt from the severance tax. This exemption is temporary for a period of twenty-four (24) months from the date of first production. Authority for determining whether production is from a new pool rests with the Kansas Corporation Commission.

K.S.A. 79-4217 was amended by the 1998 legislature to provide for a seven year exemption from severance tax on any incremental increase in oil or gas production which is the result of a qualifying production enhancement project begun after July 1, 1998. The Kansas Corporation Commission established a process to certify that the production for which an exemption is sought is the result of a qualifying production enhancement project as set out in statute. The exemption certification process is covered under K.A.R. 82-3-900 *et. seq.*

K.S.A. 79-2001 permits production from oil wells producing above 2000 feet at a rate of 3 bbl per day to be exempt from the ad valorem tax excluding the equipment value, and royalty interests. Production of 5 bbl or less from 2001 feet and deeper are treated the same under the exemption. For gas wells that are 100 MCF per day or less, the production is exempt from ad valorem taxes.

4. Name of tax: Severance.
5. Statutory citation: Severance tax: K.S.A. 1994 Supp. 79-4216 et seq. K.S.A. 79-4217 (b); Ad valorem tax: K.S.A. 79-329; Exemptions: K.S.A. 79-2011.

Land Leasing Information

1. Leasing Method: Please read the general summary.
2. Notice Method:
3. Minimum bidding \$ (per acre):
4. Qualification of the bidder:
5. State Statutes:
6. Maximum acres:
7. Contact: Department of Administration, Phone: (785) 296-3011.

Naturally Occurring Radioactive Materials (NORM)

1. Regulating Agency: Radiation Control Program, Bureau of Air and Radiation; Kansas Department of Health and Environment.
2. Relevant Statute/Regulations: There are no existing or proposed regulations specific to NORM.
3. Scope: The State of Kansas Radiation Protection Regulations apply to all persons who receive, possess, use, transfer, own or acquire any source of radiation.
4. Licensing: NORM responses are evaluated to decide if radioactive materials license is required for the material.
5. Cleaning Equipment: Descaling or cleaning operations would require a Radioactive Materials License if scale or sludge contains significant quantities of radioactive materials such as Radium-226.
6. Disposal of Waste: There is currently no satisfactory cost-effective way of disposing of this material.
7. Subsequent Use of Equipment: Release criterion of contaminated equipment would fall under the scope of Kansas Radiation Protection Regulations. Specific requirements would be addressed depending upon the scope of the licensee's proposed activities.
8. Subsequent Use of materials: Release criterion of contaminated materials would fall under the scope of Kansas Radiation Protection Regulations. Specific requirements would be addressed depending upon the scope of the licensee's proposed

activities.

9. Release/Sale of NORM-Contaminated Land: A radioactive materials license would be required and appropriately transferred to the new owners.
10. Projected Volume of stored NORM in the State: The extent of NORM contamination in oil and gas operations in Kansas has not been assessed. It has been proposed that the Department contact with a consultant to assess the extent of NORM contamination in Kansas.
11. Respondent: David Whifill

Underground Injection Control

Kansas Corporation Commission, Conservation Division permits injection wells after application, notice and hearing if necessary. K.A.R. 82-3-400 *et seq.*

KENTUCKY

Administration

1. State agency: Division of Oil and Gas Conservation, P. O. Box 2244, Frankfort, KY 40601. Phone (502) 573-0147.
2. Docketing procedure: Any party to a property may request a hearing and said hearing will be set.
 - (a) Emergency orders: Upon application by an operator.
 - (b) Notice: 20 days in advance of the date set for the hearing.

Bond

1. Compliance bond required: Yes.

0 - 500 feet	\$ 500
501 - 1,000 feet	1,000
1,001 - 1,500 feet	1,500
1,501 - 2,000 feet	2,000
2,001 - 2,500 feet	2,500
2,501 - 3,000 feet	3,000
3,001 - 3,500 feet	3,500
3,501 - 4,000 feet	4,000
over 4,000 feet	5,000

or an amount set by the Kentucky Oil and Gas
Conservation Commission

2. Conditions of bond: All records must be filed and well properly plugged.
 - (a) Amount per well: See table above.
 - (b) Amount of blanket bond: \$10,000 – 1- 25 wells
 \$25,000 - 25 - 100 wells
 \$50,000 – 100 – 500 wells
 \$100,000 – over 500 wells for “qualified” operators that had an existing blanket bond on file with the Division as of 7-12-06. For “non-qualified” operators or new operators, blanket bonds are as follows:
 \$50,000 – 1-100 wells
 \$100,000 – over 100 wells.

Spacing

1. Spacing requirements: Yes.
 - (a) Density: 2.88 acres for shallow oil wells in non coal area
 7.85 acres for shallow oil wells in coal area
 18.03 acres for shallow gas well spacing
 Deep Wells: As established by Kentucky Oil and Gas Conservation Commission, or in lieu of approved spacing as follows:
 70 acres for oil wells between 4,000-7,000 feet
 281 acres for gas wells between 4,000-7,000 feet
 143 acres for oil wells deeper than 7,000 feet
 574 acres for gas wells deeper than 7,000 feet

- (b) Lineal: Oil well (non-coal area & less than 2000 feet) - 400 feet between wells and 200 feet from mineral boundary. Oil well (coal areas and wells in non-coal area between 2000 feet and 4000 feet) - 660 feet between wells and 330 feet from mineral boundary in coal producing areas and non-coal areas greater than 2,000 feet. Gas well - 1,000 feet between wells and 500 feet from mineral boundary for gas wells less than 4,000 feet deep. Varies with depth and geographic area.

2. Exceptions: Yes.

- (a) Basis: For tracts that are so situated that they have no drillable site.
- (b) Approval: By notice and hearing.

Pooling

- 1. Authority to establish voluntary: Yes.
- 2. Authority to establish compulsory: Yes.

Drilling Permit

- 1. Require permits for:
 - (a) Drilling a producing or service well: Yes, by statute.
 - (b) Seismic drilling? No.
 - (c) Recompletion? No restriction so long as it complies with spacing requirements and meets bonding requirements.
 - (d) Plugging and abandoning? Yes.
- 2. Permit fee:
 - (a) Drilling: \$300.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
 - (e) Well transfer fee: \$25.
- 3. Require filing report of work performed: Yes.

Vertical Deviation

- 1. Regulation requirement: For directional and horizontal wells.
 - (a) When is directional survey necessary? For all wells drilled horizontally or intentionally deviated to change the bottom hole location and for deep wells upon the request of the Kentucky Oil and Gas Conservation Commission.
 - (b) Filing of survey required? Yes.

Casing and Tubing

- 1. Minimum amount required:

- (a) Surface casing: Yes, at least 30' below deepest fresh water.
 - (b) Production casing: No.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes, circulate to surface, 30 feet below fresh water depth.
 - (b) Production casing: No, except for injection wells circulate to surface.
 - (c) Setting time: No.
 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes.
 - (a) Time limit: 90 days after completion of drilling.
 - (b) Where submitted: Division of Oil and Gas, P. O. Box 2244, Frankfort, KY 40601.
2. Well logs required to be filed: Yes.
 - (a) Time limit: 90 days.
 - (b) Where submitted: Division of Oil and Gas, P. O. Box 2244, Frankfort, KY 40601.
 - (c) Confidential time period: Yes, upon request for one year maximum.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
3. Multiple completion regulation: No authorization required.
 - (a) Approval obtained.
4. Commingling in well bore: No requirements.
 - (a) Approval obtained:

Oil Production

1. Definition of an oil well: Oil Well - means any well which produces one (1) barrel or more of oil to each ten thousand (10,000) cubic feet of natural gas.
2. Potential tests required: No.
 - (a) Time interval:
 - (b) Witness required:
3. Statewide allowable: No.

- (a) Pool allowable:
- (b) Well allowable:
- (c) Exempt allowable:
- 4. Maximum gas-oil ratio: 10,000 cubic feet to 1 barrel crude oil.
 - (a) Provision for limiting gas-oil ratio: No.
 - (b) Exception to limiting gas-oil ratio:
- 5. Bottom-hole pressure test reports required: Only if such test is run by the operator.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: No requirements.
- 7. Measurement involving meters: No requirements.
- 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: No.
 - (c) Time limit: By February 28 of following year to the Department of Revenue.
By April 15 of following year to the Division of Oil and Gas.

Gas Production

- 1. Definition of a gas well: Gas Well - means any well which:
 - (a) Produces natural gas not associated or blended with crude petroleum oil any time during production; or
 - (b) Produces more than ten thousand (10,000) cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon.
- 2. Pressure base 14.73 psia @ 60 degrees F.
- 3. Initial potential tests: No requirement.
 - (a) Time interval:
 - (b) Witness required:
- 4. Statewide allowable: No.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
- 5. Bottom-hole pressure test reports required: Only if run by operator.

- (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: No requirements.
- 7. Measurement involving meters: No requirement.
- 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: Yes, to the Division of Oil and Gas.
 - (c) Time limit: By February 28 of following year to the Department of Revenue.
By April 15 of following year to the Division of Oil and Gas.

Water Disposal

- 1. State agencies that control disposal of produced salt water: Surface - Division of Water, 18 Reilly Road, Frankfort, KY 40601; Underground - Division of Oil and Gas Conservation, P. O. Box 2244, Frankfort, KY 40601.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 51%.
 - (b) Royalty interest: 51%.

Taxation

Gas gross production tax = 4.5%
 Gas ad valorem tax = approximately 1%
 Total gas tax burden = approximately 5.5%

Oil gross production tax = 4.5%
 Oil ad valorem tax = approximately 1%
 Total oil tax burden = approximately 5.5%

- 1. Tax collecting agency: Revenue Cabinet, Capitol Annex, Frankfort, KY 40601.
- 2. How tax is computed: Gross production tax - Natural gas is taxed at 4.5% of the gross value of the gas severed and processed in Kentucky. Oil is taxed at 4.5% of the market value of all the oil produced in the state. The oil tax is imposed and attached when the oil is first transported from the tanks or other receptacle located at the place of production, and shall be imposed upon all persons owning an interest in such oil.

Ad valorem tax - Kentucky has a broadly based classified property tax system. Total ad valorem tax includes both state and local taxes and is approximately 1% throughout the state. The state ad valorem tax rate for natural gas and oil property that is both producing and undeveloped was .148% in 1999. The .148% tax rate is expressed in cents per \$100 of assessed value. The total ad valorem tax rate varies by local district and depends on the local rates.

- 3. Exemptions or exceptions: A tax credit of 4.5% is available for inactive oil and gas wells. An inactive well is classified as one that has been inactive for a consecutive two-year period or a well that has been plugged and abandoned, in accordance with regulations determined by the Department of Mines and Minerals.
- 4. Name of tax: Gross Production.

5. Statutory citation: Natural gas tax - KRS 143A.010 et seq.; Oil tax - KRS 137.120; Ad valorem tax - KRS 132.820.

Land Leasing Information

No regulations at this time.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Cabinet for Health and Family Services, 275 East Main, Frankfort, KY 40601. Phone: (502) 564-3700, Fax: (502) 564-1492.
2. Relevant Statute/Regulations: CRCPD states that "TENORM does not include the natural radioactivity of rocks, soil, or background but instead refers to materials whose radioactivity is technologically enhanced by controlled practices." Part N of CRCPD states TENORM is "radioactive material." 902 KAR 100:010(176) states "radioactive material" means a solid, liquid, or gas which emits radiation spontaneously. TENORM falls into this area as defined by the CRCPD.
3. Scope: Given the above 902 KAR 100 could be considered applicable to TENORM. All the areas listed below would fall under existing regulations. If TENORM is not considered radioactive material, then Kentucky would have regulations applicable to this material.
4. Licensing:
5. Cleaning:
6. Disposal of waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the state:
11. Respondent: Dewey Crawford.

LOUISIANA

Administration

1. State agency: Office of Conservation, P. O. Box 94275, Capitol Station, Baton Rouge, LA 70804-9275. Phone (225) 342-5540.
2. Docketing procedure: LSA-RS-30:6(F) - Any interested person has the right to have the Commissioner call a hearing for the purpose of taking action in respect to a matter within the jurisdiction of the Commissioner by making a request therefore in writing. Upon receiving the request the Commissioner shall promptly call a hearing. After the hearing, and with all convenient speed and in any event within thirty days after the conclusion of the hearing, the Commissioner shall take whatever action he deems appropriate with regard to the subject matter. In the event of failure or refusal of the Commissioner to issue an order within the period of thirty days, he may be compelled to do so by mandamus at the suit of any interested person. LSA-RS-30:4(C) - The Commissioner has authority to make after notice and hearing as provided in this Chapter, any reasonable rules, regulations, and orders that are necessary from time to time in the proper administration and enforcement of this Chapter, including rules, regulations, or orders. Based on the above cited authority, the Commissioner of Conservation adopted "Rules of Procedure for Conducting Hearings before the Commissioner of Conservation of the State of Louisiana," effective April 1, 1964, and last revised effective October 11, 1983.
 - (a) Emergency orders: LSA-RS-30: 6C - If the Commissioner finds an existing emergency which in his judgment requires the making, changing, renewal, or extension of a rule, regulation, or order without first having a hearing, the emergency rule, regulation, or order shall have the same validity as if a hearing had been held after due notice. The emergency rule, regulation, or order shall remain in force no longer than fifteen days from its effective date. In any event, it shall expire when the rule, regulation, or order made after notice and hearing with respect to the same subject matter becomes effective.
 - (b) Notice: LSA-RS-30: 6B - No rules, regulation, order, or change, renewal, or extension thereof, shall, in the absence of an emergency, be made by the Commissioner under the provisions of this Chapter except after a public hearing upon at least ten days' notice given in the manner and form prescribed by the Commissioner. This hearing shall be held at a time and place and in the manner prescribed by the Commissioner. The Commissioner, in his discretion, may designate a member of his staff to conduct public hearings on his behalf. Any person having an interest in the subject matter of the hearing shall be entitled to be heard. Provided, however, that whenever any application shall be made to the Commissioner of Conservation for creation, revision or modification of any unit or units for production of oil or gas, or for adoption of any plan for spacing of wells or for cycling of gas, pressure maintenance or restoration, or other plan of secondary recovery, the applicant shall be required to file with the application two copies of a map of such unit or units or well spacing pattern or two explanations of such plan of cycling, pressure maintenance or restoration, or other secondary recovery program and at least thirty (30) days' notice shall be given of the hearing to be held thereon, in the manner prescribed by the Commissioner of Conservation, and a copy of such plat or explanation of program shall remain on file in the Office of Conservation in Baton Rouge, and in the Office of the District Manager of the Conservation District in which the property is located, and be open for public inspection, at least thirty (30) days prior to such hearing.

Financial Security

1. Compliance bond required: May be required.
2. Conditions of Financial Security: Statewide Order No. 29-B (LAC 43: XIX.104)
 - (A) Unless otherwise provided by the statutes, rules and regulations of the Office of Conservation, financial security shall be required by the operator of record (operator) pursuant to this section for each applicable well as further set forth herein in order to ensure that such well is plugged and abandoned and associated site restoration is accomplished. A compliance order and/or civil penalty which has been timely satisfied shall not cause an operator to be considered a non-compliant operator for the purpose of this section.

(1) Permit to Drill

- (a) On or after July 1, 2000 the applicant for a permit to drill must provide financial security for such well in accordance with the following:
 - (i) An operator who has exhibited a record of compliance with the statutes, rules and regulations of the Office of Conservation for a period of 48 months immediately preceding the permit date of the well and who has no outstanding violations shall be exempt from providing financial security under this section.
 - (ii) An operator who has not been a registered operator of record for a period of 48 months immediately preceding the permit date of the well in question shall comply with the following:
 - (a) An operator who has not previously been an operator of a well (drilling, drilled, or completed) shall provide financial security in a form acceptable to the commissioner prior to issuance of a permit to drill.
 - (b) An operator who has previously been an operator of a well (drilling, drilled or completed) for less than the prescribed 48 months but has otherwise exhibited a record of compliance with the statutes, rules and regulations of the Office of Conservation and who has no outstanding violations shall provide financial security in a form acceptable to the commissioner within 30 days of completion date as reported on Form Comp or Form WH-1.
 - (iii) An operator who has not exhibited a record of compliance with the statutes, rules, and regulations of the Office of Conservation for a period of 48 months immediately preceding the permit date of the well shall provide financial security in a form acceptable to the commissioner prior to issuance of permit to drill.

(2) Amended Permit to Drill/Change of Operator

- (a) Any application to amend permit to drill for change of operator must be accompanied by financial security in accordance with the following:
 - (i) An operator who has previously been an operator of a well for a period of at least 48 months immediately preceding the amended permit to drill date, who has exhibited a record of compliance with the statutes, rules and regulations of the Office of Conservation and who has no outstanding violations shall be exempt from providing financial security under this section.
 - (ii) Any operator who does not meet the criteria specified in 104.A.2.a.i. above shall provide financial security in a form acceptable to the commissioner prior to issuance of an amended permit to drill.
- (3) Financial security in a form acceptable to the commissioner shall be provided prior to issuance of a permit to drill or amended permit to drill to any operator which includes a primary officer therein who is or was a primary officer of an operator assigned an orphan status.
- (4) The financial security requirements provided herein shall apply to Class V wells as defined in LAC 43:XVII.103 for which an application for a permit to drill or amended permit to drill is submitted on and after July 1, 2000, at the discretion of the commissioner.

- (B) Compliance with this financial security requirement shall be provided by any of the following or a

combination thereof:

- (1) certificate of deposit issued in sole favor of the Office of Conservation in a form prescribed by the commissioner from a financial institution acceptable to the commissioner. A certificate of deposit may not be withdrawn, canceled, rolled over or amended in any manner without the approval of the commissioner; or
- (2) a performance bond in sole favor of the Office of Conservation in a form prescribed by the commissioner issued by an appropriate institution authorized to do business in the state of Louisiana; or
- (3) letter of credit in sole favor of the Office of Conservation in a form prescribed by the commissioner issued by a financial institution acceptable to the commissioner.

(C) Financial Security Amount:

(1) Land Location

- (a) Individual well financial security shall be provided in accordance with the following:

<u>Depth (ft.)</u>	<u>Amount</u>
<3,000	\$1.00 per foot
3,001 - 10,000	\$2.00 per foot
>10,001	\$3.00 per foot

- (b) Blanket financial security shall be provided in accordance with the following:

<u>Total Number of Wells</u>	<u>Amount</u>
<10	\$ 25,000.00
11-99	\$125,000.00
>100	\$250,000.00

- (2) *Water Location - Inland Lakes and Bays* - any water location in the coastal zone area as defined in LSA-R.S. 49:214.27 except in a field designated as offshore by the commissioner.

- (a) Individual well financial security shall be provided in the amount of \$8.00 per foot of well depth.
- (b) Blanket financial security shall be provided in accordance with the following:

<u>Total Number of Wells</u>	<u>Amount</u>
<10	\$ 125,000.00
11-99	\$ 625,000.00
>100	\$1,250,000.00

- (3) *Water Location - Offshore* - any water location in a field designated as offshore by the commissioner.

- (a) Individual well financial security shall be provided in the amount of \$12.00 per foot of well depth.
- (b) Blanket financial security shall be provided in accordance with the following:

<u>Total Number of Wells</u>	<u>Amount</u>
<10	\$ 250,000.00
11-99	\$1,250,000.00
>100	\$2,500,000.00

- (4) An operator of land location wells and water location wells who elects to provide blanket financial security

shall be subject to an amount determined by the water location requirements.

- (5) The amount of the financial security as specified above may be increased at the discretion of the commissioner.
- (D) A change of name by a compliant operator of record through acquisition, merger, or otherwise does not preclude said successor operator from meeting the requirements for exemption from financial security under this section.
- (E) The commissioner retains the right to utilize the financial security provided for a well in responding to an emergency applicable to said well in accordance with R.S. 30:6.1.
- (F) Financial security shall remain in effect until release thereof is granted by the commissioner pursuant to written request by the operator. Such release shall only be granted after plugging and abandonment and associated site restoration is completed and inspection thereof indicates compliance with applicable regulations or upon transfer of such well to an exempt operator. In the event provider of financial security becomes insolvent, operator shall provide substitute form of financial security within 30 days of notification thereof.
- (G) Plugging and abandonment of a well, associated site restoration, and release of financial security constitutes a rebuttable presumption of proper closure but does not relieve the operator from further claim by the commissioner should it be determined that further remedial action is required.
- (H) In the event that an operator has previously provided financial security pursuant to LAC 43:XIX.104, such operator shall provide increased financial security, if required to remain in compliance with this section, within 30 days after notice from the commissioner.

Authority Note: Promulgated in accordance with R.S. 30:4 et seq.

Historical Note: Adopted by the Department of Conservation (August 1943), amended by the Department of Natural Resources, Office of Conservation LR 26:1306 (June 2000), LR 27:1917 (November 2001).

Spacing

1. Spacing requirements:

- (a) Density: No minimum acreage requirements for oil or gas wells.
- (b) Lineal: Statewide Order No. 29-E (LAC 43:XIX.1901) applies and states that wells drilled in search of gas shall not be located closer than 330 feet to any property line nor closer than 2,000 feet to any other well completed in, drilling to, or for which a permit shall have been granted to drill to, the same pool.

Where Statewide Order No. 29-E (LAC 43:XIX.1901) is applicable, no spacing shall be required for oil wells drilled in search of oil to depths less than 3,000 feet subsea. Wells drilled in search of oil to depths below 3,000 feet subsea shall not be located closer than 330 feet from any property line nor closer than 900 feet from any other well completed in, drilling to, or for which a permit shall have been granted to drill to, the same pool.

Statewide Order No. 29-H, applicable to "new" pools, has been terminated by Statewide Order No. 29-H-1. Spacing previously developed under Statewide Order No. 29-H will be regulated by Statewide Order No. 29-E. Any special order which adopted the spacing requirements of Statewide Order No. 29-H has been amended requiring the spacing provisions of Statewide Order 29-E (LAC 43:XIX.1901).

2. Exceptions: Yes.

- (a) Basis: Refer to Statewide Order No. 29-E (LAC 43:XIX.1901).
- (b) Approval: By letter setting forth all pertinent facts and reasons why granting the exception is necessary.

Pooling

1. Authority to establish voluntary: No.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes, Statewide Order No. 29-B, Section II (LAC 43:XIX.103).
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes, Statewide Order No. 29-B, Section III (LAC 43:XIX.105).
 - (d) Plugging and abandoning: Yes, Statewide Order NO. 29-B, Section III (LAC 43:XIX.105).
2. Permit fee:
 - (a) Drilling: Fee schedule subject to change annually. Please refer to the Office of Conservations Web site at www.dnr.state.la.us for a complete current fee schedule.

<u>Depth (ft.)</u>	<u>Amount</u>
0 - 3,000	\$ 126
3,001 -10,000	\$ 631
10,001 - Plus	\$1,264

- (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes, Statewide Order No. 29-B, Section IV (LAC 43:XIX.107).

Vertical Deviation

1. Regulation requirement: Yes, Statewide Order No. 29-B, Section XVIII (LAC 43:XIX.135).
 - (a) When is directional survey necessary? When the well is directionally controlled and is thereby intentionally deflected from the vertical, or the surface location is less than 330 feet from the nearest property line, and the well is drilled below a depth of 3,786 feet, or the resultant lateral deviation as calculated from Inclination Survey data is a distance greater than the distance from the center of the surface location of the well bore to the nearest property line, or the well bore deviates laterally a resultant distance greater than that determined by a five degree angle from a vertical line passing through the center of the surface location of the well bore.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes, Statewide Order No. 29-B, Section V-B (LAC 43:XIX.109.B).
 - (b) Production casing: Yes, Statewide Order No. 29-B, Section V-D (LAC 43:XIX.109.D).

2. Minimum amount of cement required:
 - (a) Surface casing: Yes, Statewide Order No. 29-B, Section V-B (LAC 43:XIX.109.B).
 - (b) Production casing: Yes, Statewide Order No. 29-B, Section V-D (LAC 43:XIX.109.D).
 - (c) Setting time: Yes. Surface - "under pressure" for 12 hours. Production - "under pressure" for 12 hours, minimum total of 24 hours before initiating test or drilling plug.

3. Tubing requirements: None

Completion

1. Completion report required: Yes, Statewide Order No. 29-B, Section X (LAC 43:XIX.119).
 - (a) Time limit: Within 24 hours from time of completion. Notice may be made by telephone or telegram to the district manager if supplemented by written notice on proper form within three days from the completion date.
 - (b) Where submitted: Appropriate District Office of the Office of Conservation.
2. Well logs required to be filed: Yes, Statewide Order No. 29-B, Section IV (LAC 43:XIX.107).
 - (a) Time limit: Within 10 days after completion.
 - (b) Where submitted: Appropriate District Office of the Office of Conservation.
 - (c) Confidential time period: Yes, upon written request; (Act 4 of the Extraordinary Session of 1973) wells shallower than 15,000 feet--one year with a one-year extension; wells deeper than 15,000 feet--two years with a two-year extension; Act 691 of the Regular Session of 1979--offshore logs, upon written request--two years with a two-year extension.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes.
3. Multiple completion regulation: Yes, Statewide Order Nos. 29-C-4 (LAC 43:XIX.1301).
4. Commingling in well bore: No, except in certain circumstances we use the same procedures as selective completion equipment as outlined in Statewide Order No. 29-C-4 (LAC 43:XIX.1305(G)).
 - (a) Approval obtained: By public hearing and administratively.

Oil Production

1. Definition of an oil well: No specific definition. In the event of uncertainty, a PVT analysis is required to be conducted by the operator.
2. Potential tests required: Yes, Statewide Order No. 29-B, Section X (LAC 43:XIX.119).
 - (a) Time interval: Within five days of completion.
 - (b) Witness required: Yes, by inspectors of the Office of Conservation.
3. Statewide allowable: Yes. The Statewide allowable is the summation of individual well and unit allowables.
 - (a) Pool allowable: Yes. For poolwide units created under LSA-RS-30:5(C), a maximum efficient rate (MER) allowable based upon the productive capability of the reservoir is assigned if request is submitted by operator and

approved by Office of Conservation. Otherwise, allowable for said poolwide units is based upon number of completions in the unit and the depth bracket allowable.

For competitive units created under LSA-RS-30: 9 each unit is assigned an allowable based upon the acreage in said unit and the acreage factor (Bbls./Acre) calculated for the pool. (Acreage factor based upon acres in pool and depth bracket.)

For a single unit created under LSA-RS-30:9, the unit is assigned an allowable based upon the depth bracket or if the unit encompasses the entire reservoir it may be assigned an MER allowable if the requirements as noted above are met.

Statewide Order No. 29-H has been terminated by Statewide Order No. 29-H-1 (LAC 43:XIX.2501), effective January 1, 1980, which provides: The allowable assignment for each oil well, including those wells previously assigned allowables based on the provisions of Statewide Order No. 29-H, should be based on the Statewide Crude Oil Depth Bracket Allowable Schedule adopted by Office of Conservation Order No. 151-A-2 (LAC 43:XIX.3701), effective October 20, 1994. Essentially, allowable for units previously developed under No. 29-H will be calculated in the same manner as the three paragraphs above.

- (b) Well allowable: Yes. Depth bracket allowable formula for lease wells.
 - (c) Exempt allowable: Yes. Hardship allowables, Statewide Order No. 45-I-A (LAC 43:XIX.3501), exempt allowables, stripper fields.
 - (d) Horizontal well allowable: Maximum Efficient Rate (MER) unless determined otherwise after public hearing in competitive situations (LAC 43:XIX.3701).
4. Maximum gas-oil ratio: Yes, Statewide Order No. 45-I-A (LAC 43:XIX.3501). 2,000 cubic feet of gas per barrel of oil.
 - (a) Provision for limiting gas-oil ratio. Yes. Allowed to produce quantity of oil determined by multiplying base allowable by base GOR and dividing by GOR of well.
 - (b) Exception to limiting gas-oil ratio: Yes. Refer to Statewide Order 45-I-A (LAC 43:XIX.3501).
 5. Bottom-hole pressure test reports required: Bottom hole pressure is requested on Form DM-1-R which is filed on or before the first day of May and November. Bottom hole pressure may also be required by special field order.
 - (a) Periodical bottom-hole pressure surveys: As answered above.
 6. Commingling oil in common facilities: Yes, Statewide Order No. 29-D-1 (LAC 43:XIX.1501).
 7. Measurement involving meters: Yes, Statewide Order No. 29-G-1 (LAC 43:XIX.2301).
 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: No.
 - (b) Time limit: On or before the first day of the third calendar month following the month covered by the report or within 60 days.

Gas Production

1. Definition of a gas well: No specific definition. In the event of uncertainty, a PVT analysis is required to be conducted by the operator.

2. Pressure base 15.025 psia @ 60 degrees F.
3. Initial potential tests: Yes, Statewide Order No. 29-B, Section X (LAC 43:XIX.119).
 - (a) Time interval: Within five days of completion.
 - (b) Witness required: Yes.
4. Statewide allowable: Yes, Statewide Order No. 29-F (LAC 43:XIX.2101). The statewide allowable is the summation of individual well and unit allowables (based on well potential test).
 - (a) Pool allowable: Yes. For poolwide units created under LSA-RS-30: 5C, the summation of the individual well potential tests of wells completed in the pool.

 For competitive units created under LSA-RS 30:9, each unit shall be assigned an allowable in accordance with the procedure outlined in Statewide Order No. 29-F (LAC 43:XIX.2101).

 For a single unit created under LSA-RS-30:9, the unit allowable is based upon well potential test.
 - (b) Well allowable: Yes. Based upon well potential test.
 - (c) Exempt allowables: Yes, stripper gas fields.
5. Bottom-hole pressure test reports required: Bottom-hole pressure is requested on Form DT-1 which is filed on or before the first day of May and November. Bottom-hole pressure may also be required by special field orders.
 - (a) Periodical bottom-hole pressure surveys: As answered above.
6. Commingling of gas in common facilities: Yes, Statewide Order No. 29-D (LAC 43:XIX.1501).
7. Measurement involving meters: Yes, LSA-RS-30:44 (required by statutes).
8. Production reports: Gas production is reported by lease or unit.
 - (a) By lease: Yes.
 - (b) By well: No.
 - (c) Time limit: On or before the first day of the third calendar month following the month covered by report or within 60 days.

Water Disposal

1. State agencies that control disposal of produced salt water: Office of Conservation and Department of Environmental Quality.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: None, however, 75% - if the unit is created under the provisions of LSA-RS-30:5C (multi-well or enhanced recovery).
 - (b) Royalty interest: None, however, 75% - if the unit is created under the provisions of LSA-RS-30:5C (multi-well or enhanced recovery).

Contact: Gary Ross, Assistant Commissioner of Conservation, Louisiana Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275. Phone: (225) 342-5540.

Taxation

Gas severance tax, full rate = 26.9 cents per MCF
 Incapable oil well gas rate = 3 cents per MCF
 Incapable gas well gas rate = 1.3 cents per MCF
 Total gas tax burden = 1.3 cents up to 25.2 per MCF

Oil severance tax, full rate = 12.50% of value
 Oil severance tax, incapable rate = 6.25% of value
 Oil stripper well rate = 3.125**%
 Total oil tax burden = 3.125% to 12.50%
 **Exempt if the gross taxable value is less than \$20 barrel

1. Tax collecting agency: Department of Revenue and Taxation, Taxpayer Services Division, Severance Tax Section, P.O. Box 201, Baton Rouge, LA 70821.
2. How tax is computed: Crude oil and condensate is taxed at a full rate of 12.50% and crude oil only at an incapable rate of 6.25% of value. There is a stripper well rate of 3.125% of value for crude oil only. Gas is taxed at a full rate of 26.9 cents per MCF, and the rate is redetermined July 1 of each year.

The incapable rates are as follows:

- (a) oil well gas – 3 cents per MCF
- (b) gas well gas – 1.3 cents per MCF

3. Name of tax: Severance.
4. Statutory citation: Louisiana Revised Statutes, Title 47, Section 631 through 646.
5. Contact: Sebrena Coleman, Revenue Tax Director, Taxpayer Services Division, Severance Tax Section, Louisiana Department of Revenue, P.O. Box 201, Baton Rouge, LA 70821-0201. Phone: (225) 219-2200.

Land Leasing Information

1. Leasing Method: Sealed, public bid opened at monthly Mineral Lease Sale held on second Wednesday of every month.
2. Notice Method: Publication of tract description up for lease in the official journal of the state and in the official journal of the parish where the lands are located - must appear in these journals not more than 60 days prior to the date for the opening bids for that tract.
3. Minimum bidding \$ (per acre): Royalty bid cannot be less than 1/8 of all oil or gas produced and saved or utilized (LSA-R.S. 30:127).
4. Qualification of the bidder: Any person or entity authorized to do business in the state of Louisiana can submit bids.
5. State Statutes: LSA-R.S. 30:124-127
6. Maximum acres: 2,500 acres by State Mineral Board Policy.
7. Contact: Rick Heck, Director of Petroleum Lands, Petroleum Lands Division, Office of Mineral Resources, P. O. Box 2827, Baton Rouge, LA 70821-2827. Phone: (225) 342-6122.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Louisiana Department of Environmental Quality, Office of Environmental Compliance, Emergency and Radiological Services Division, Licensing and Registrations Sections, P.O. Box 4312, Baton Rouge, LA 70821-4312. Phone: (225) 219-3021, Fax: (225) 219-3154.
2. Relevant Statute/Regulations: Louisiana Administrative Code, Title 33, Part 15, Chapter 14 Regulation and Licensing of Naturally Occurring Radioactive Material (NORM), amended January 1995.
3. Scope: The regulations say: "These regulations apply to any person who engages in waste generation, extraction, mining, beneficiating, processing, possession, use, transfer, treatment, transportation, or disposal of NORM or recycling of NORM contaminated equipment in such a manner as to technologically alter the natural sources of radiation or their potential exposure pathways to humans." Yet, in practice, the State of Louisiana has put NORM regulatory emphasis on the oil and gas industry. Largely, because the occurrence of NORM has predominately been found in the oil and gas industry. There are few other industries such as paper and pulp and petrochemical where the regulation of NORM has been enforced.
4. Licensing: Louisiana created a general license requirement of all oil and gas operators/companies who own or operate sites where NORM contamination has been discovered. Upon discovery of the presence of NORM, an operator/company is required to notify the State of Louisiana of the site using the NORM notification form. The information is compiled into a database and each operator/company is assigned a general license number and each site is tracked by a site specific number. At the present, the State of Louisiana has approximately 450 NORM general licenses.

For companies engaged in providing NORM decontamination, handling, disposal, and other related NORM services, the State of Louisiana requires such companies to possess a NORM specific license issued from the Department or another agreement state. At the present, the State of Louisiana has 22 companies specifically licensed through the State of Louisiana.

5. Cleaning Equipment: NORM general licensees are allowed to *...perform maintenance on vessels, tanks, tubular goods, or water treatment systems, or the clearing of pipe lines to maintain oil and gas production...* under the onsite maintenance provision stated in LAC33:XV.1408.A.4., provided that written worker protection procedures are submitted to the Department, and that the maximum radiation level does not exceed two millirem per hour.

The decontamination of NORM contaminated equipment for release for unrestricted use is reserved for companies that possess a NORM specific license from the State of Louisiana or an agreement state. The handling and decontamination of NORM contaminated equipment and sites is largely performed by companies that possess a NORM specific license.

6. Disposal of Waste: At present, the following are disposal option available to oil and gas operators:
 - (a) Commercial treatment by method of landfarming. There are one or two commercial landfarms in Louisiana permitted for NOW disposal that accept NORM with concentration less than 30 picocuries per gram of Ra-226 or Ra-228.
 - (b) Non-commercial Downhole Disposal into wellbore to be plugged and abandoned.
 - (c) Commercial deep well injection. There are two commercial facilities in the state of Texas permitted and licensed to inject NOW/NORM into an injection well.
7. Subsequent Use of Equipment: NORM contaminated tubular goods and pipe are often decontaminated and then, reused. That which is unusable is decontaminated and sold as scrap.
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land: To release the site, documentation is required supporting the removal of the NORM. Included in the documentation, would be a radiation survey of the area where the NORM was present, soil sample data, and records supporting the transfer of the equipment or NORM waste for treatment, storage, or disposal. The release criteria for a site is outlined in Louisiana's NORM Implementation Manual and in LAC 33:XV.1417.

10. Projected Volume of stored NORM in the State: It is uncertain how much NORM is being stored in the state. In 1994 and 1995, two disposal options came available that provided an outlet for many operators to begin moving their inventory of NORM waste for disposal. One of the options existed in Louisiana through a company that operated a commercial landfarm specifically permitted/licensed to accept NOW/NORM waste. The other option existed in Texas through a company that operated a commercial injection well permitted/licensed to accept NOW/NORM waste.
11. Respondent: Brad Schexnayder, Licensing and Registrations Section, P.O. Box 4312, Baton Rouge, LA 70821-4312. Phone: (225) 219-3021, Fax: (225) 219-3154.

MARYLAND

Administration

1. State agency: Maryland Department of the Environment, Water Management Administration, Minerals, Oil and Gas Division, 1800 Washington Blvd., Baltimore, MD 21230.
2. Docketing procedure: The Department may act either upon its own motion or the petition of any interested person and shall promptly fix a date for a hearing and cause notice of the hearing to be given. The public hearing shall be held at the time and place described by the Department. Any interested person is entitled to be heard by the Department. Section 14-114(a) and (d), Annotated Code of the Public General Laws of Maryland (PLM).
 - (a) Emergency orders: The Department is authorized to issue an emergency order without notice or hearing. An emergency order may not remain effective for more than 15 days. Section 14-114(b), PLM.
 - (b) Notice: Except for an emergency, a rule, regulation, order or amendment may not be made by the Department without a public hearing upon at least 10 days notice. The Department of the Environment is responsible to give notice. Section 14-114(a), PLM.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: A bond is required on the form obtained from the Department of the Environment with regard to drilling, plugging and abandoning wells drilled for oil and gas. Said bond will not be released until all of the permit holder's obligations under the laws have been fulfilled to the satisfaction of the Department. Section 14-111(a)(5),(d)(1), PLM, 26.19.01.06(c)(5) and 26.19.01.13 CMR.
 - (a) Amount per well: No minimum.
\$100,000 maximum. Section 14-111(a)(5), PLM; 26.19.01.06(C)(5)(a) CMR.
 - (b) Amount of blanket bond: No minimum.
\$500,000 maximum. Section 14-111(a)(5), PLM; 26.19.01.06(C)(5)(a) CMR.

Spacing

1. Spacing requirements: Yes.
 - (a) Density: No proration units formed in Maryland for oil -- only voluntary units for gas.
 - (b) Lineal: 2,000 ft. from existing gas well, 1,320 ft. from existing oil well, 1,000 ft. from property line, 1,000 ft. from any occupied house, school, church, public building or place of public meeting for both oil and gas wells, 26.19.01.09 (C,D,E,F & G) and 26.19.08.06, Code of Maryland Regulations (CMR) and Section 14-112(a),(b)(c), PLM. Drilling prohibited in the Chesapeake Bay or its tributaries 26.19.01.09(A).
2. Exceptions: Yes. 26.19.01.09 (C, D, E, F & G), CMR.
 - (a) Basis: No permit will be issued to drill a well within 1,000 ft. of the boundary of a tract of land or the boundary of tracts of land included in a pooling agreement or within 1,000 ft. from any occupied dwelling house, school, church, public building or place of public meeting unless the permit holder has made a satisfactory written agreement with the oil and gas owner and lessee of such adjacent land or building. The Department may issue a permit to drill a well within 1,000 ft. of a boundary of a tract of land if it is impossible to locate a well 1,000 ft. or more from the boundaries of the tract.
 - (b) Approval: Following notice and hearing by the Department.

Pooling

1. Authority to establish voluntary: Yes. Section 14-113, PLM.
2. Authority to establish compulsory: No.

Drilling Permit

1. Require permits for:
 - (a) Drilling an exploration or gas storage well: Yes. Section 14-104, PLM, and 26.19.01.06(A), CMR. Conversion from exploration to production well requires permit modification, 26.19.01.09(K), CMR.
 - (b) Seismic Operations: Yes. Road access permit necessary from State Highway Administration if on state/federal roads. 26.19.01.03, CMR.
 - (c) Recompletion: Requires permit modification. 26.19.01.14(A)(1 & 2).
 - (d) Plugging and abandoning: No. Requires Departmental notification and affidavit of work performed, within Departmental guidelines, by operator. 26.19.01.12, CMR.
2. Permit fee:
 - (a) Drilling: None.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: No fee for filing completion report.
3. Require filing report of work performed: Yes. Completion report. 26.19.01.10(V), CMR.

Vertical Deviation

1. Regulation requirement: Yes. No more than 3° from vertical, 26.19.01.11, CMR.
 - (a) When is directional survey necessary? When correlative rights are in dispute, the Department may require directional and deviational surveys at the operators' expense, 26.19.01.11(D), CMR.
 - (b) Filing of survey required: No.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes. Surface casing to extend at least 100 ft. below the deepest known fresh water aquifer, or the deepest known workable coal seam, whichever is deeper. 26.19.01.10(O)(4), CMR.
 - (b) Production casing: Yes. The casing should be of a type and weight sufficient for the depth and formation pressures anticipated. 26.19.01.10(S).

2. Minimum amount of cement required:
 - (a) Surface casing: Yes. Annular surface return. 26.19.01.10(P).
 - (b) Production casing: Yes. 26.19.01.10(S).
 - (c) Setting time: Yes. 12 hours. 26.19.01.10(P)(3) and 26.19.01.10(S)(4).
3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes. Section 14-111(a)(1), PLM and 26.19.01.10(V).
 - (a) Time limit: Within 30 days after completion of the well.
 - (b) Where submitted: Maryland Department of the Environment, Water Management Administration, Minerals, Oil & Gas Division, 2500 Broening Highway, Baltimore, MD 21224.
2. Well logs required to be filed: Yes. 26.19.01.10(V)(10), CMR.
 - (a) Time limit: Within 30 days after completion of the well.
 - (b) Where submitted: Maryland Department of the Environment, Water Management Administration, Minerals, Oil & Gas Division, 2500 Broening Highway, Baltimore, MD 21224.
 - (c) Confidential time period: Yes. All information is held confidential until the operator releases such information.
 - (d) Available for public use: Yes, after operator releases confidential information.
 - (e) Log catalog available: Yes.
3. Multiple completion regulation: Yes.
 - (a) Approval obtained: Requires permit modification. 26.19.01.14(A)(1), CMR.
4. Commingling in well bore: Yes.
 - (a) Approval obtained: Requires permit modification. 26.19.01.14(A)(2), CMR.

Oil Production

1. Definition of an oil well: "Oil" means crude petroleum oil and other hydrocarbons regardless of gravity, which are produced at the wellhead in liquid form, except liquid hydrocarbons known as distillate or condensate recovered or extracted from gas. An oil well would be the drilled hole through which oil is produced. Section 14-102(f), PLM, and 26.19.01.01(B)(32), CMR.
2. Potential tests required: Yes. 26.19.01.10(V)(8), CMR.
 - (a) Time interval: Within 30 days after completion of the well.

- (b) Witness required: No.
- 3. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
- 4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: N/A.
 - (b) Exception to limiting gas-oil ratio: N/A.
- 5. Bottom-hole pressure test reports required: Yes. Initially. 26.19.01.10(V)(8), CMR.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: Yes.
- 7. Measurement involving meters: Yes. The operator must verify the accuracy of oil meters. 26.19.01.10(N), CMR.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. 26.19.01.10(Y), CMR.
 - (c) Time limit: The operator must file a monthly production report quarterly to the Maryland Department of the Environment, Minerals, Oil & Gas Division.

Gas Production

- 1. Definition of a gas well: "Gas" means all natural gas and other fluid hydrocarbons, not defined as oil, which are produced from a natural reservoir. A gas well would be the drilled hole through which gas is produced. Section 14-102(e), PLM, and 26.19.01.01(B)(20), CMR.
- 2. Pressure base: None statewide. Garrett County is 14.73 psia @ 60 degrees F. Public Local Law of Garrett County, Sec. 27-2(j) 1971 Edition, as amended in 1978.
- 3. Initial potential tests: Yes. 26.19.01.10(V)(8), CMR.
 - (a) Time interval: Within 30 days after completion of the well.
 - (b) Witness required: No.
- 4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.

5. Bottom-hole pressure test reports required: Yes, initially. 26.19.01.10(V)(8), CMR.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: Yes.
7. Measurement involving meters: Yes. Section 14-119(a), PLM. A person who is the owner or operator of any gas well may not willfully take gas from the well unless the gas is metered by a standard metering system. Also 26.19.01.10(N), CMR.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. 26.19.01.10(Y), CMR.
 - (c) Time limit: The operator must file a monthly production report quarterly to the Maryland Department of the Environment, Minerals, Oil & Gas Division.

Water Disposal

1. State agencies that control disposal of produced salt water: The Hazardous and Solid Waste Administration of the Department of the Environment would, upon application, issue a discharge permit controlling both surface and subsurface hazardous or industrial wastes.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: No.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: N/A.
 - (b) Royalty interest: N/A.

Taxation

There is no statewide tax on oil and gas in Maryland. The only countywide tax that exists is a gas production tax in Garrett County.

1. Tax collecting agency: Garrett County Treasurer and Tax Collector, 203 S. Fourth Street, Oakland, MD 21550.
 - (a) Statewide: None.
 - (b) Countywide: Only Garrett County.
2. How tax is computed: Garrett County's gas production tax is computed as 7% of the gross wholesale market value of gas production. Out of this 7% of gross wholesale market value, 2.8% is the purchaser's proportion, and 4.2% is the producer's proportion.
3. Exemptions or exceptions: No.
4. Name of tax: Gas Production.

5. Statutory citation: 1957 Garrett County Code, Section 428, 1951, Chapter 265, Section 302(A) of Annotated Code.

Land Leasing Information

Regulations pending at this time.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environment, Minerals, Oil and Gas Division, 2500 Broening Highway, Baltimore, MD 21224. Phone: (410) 631-8055.
2. Relevant Statute/Regulations: No regulations or laws exist or are proposed regarding NORM in oil and gas production.
3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land: Not applicable.
10. Projected Volume of stored NORM in the State:
11. Respondent: C. Edmon Larrimore

MICHIGAN

Administration

1. State agency: Office of Geological Survey, Department of Environmental Quality, P.O. Box 30256, Lansing, MI 48909. Phone (517) 241-1515. (Supervisor of Wells - same address).
2. Docketing procedure: Petition for matters to be heard before the Supervisor of Wells. Section 61516, Natural Resources and Environmental Protection Act, Act 451 of 1994, as amended (NREPA); Administrative Rules R 324.1201 through R 324.1212.
 - (a) Emergency orders: Yes. By Supervisor of Wells set forth in Section 61516 of NREPA. Remains in full force and effect no more than 21 days. Hearing may be held in the interim and a permanent order is issued pursuant thereto.
 - (b) Notice: Twenty-one days prior to date of hearing (R 324.1204). The petitioner must furnish proof of publication and affidavits of proof of mailing by first class mail or personal service.

Bond

1. Compliance bond required: Yes. R 324.210, R 324.211.
2. Conditions of bond: Remaining in full force and effect until such time the well or wells are properly plugged and abandoned or sold and transferred to the new owner and released by the Supervisor of Wells. R 324.213, R 324.214, R 324.215, and R 324.216.
 - (a) Amount per well: Dependent on well depth, \$10,000 - \$30,000. R 324.212.
 - (b) Amount of blanket bond: Dependent on well depth, \$100,000 - \$250,000. R 324.212.

Spacing

1. Spacing requirements: Minimum 40-acre drilling unit conforming to governmental surveyed quarter-quarter section of land. Wells located approximately 1,320 feet apart. R 324.301.
 - (a) Density: Oil well - 40 acres. Gas well - 40 acres. R 324.301.
 - (b) Lineal: Oil well - 1,320 feet. Gas well - 1,320 feet. R 324.301 (b).
2. Exceptions: Yes. R 324.301 (2) and R 324.303.
 - (a) Basis: Evidence and testimony.
 - (b) Approval: By order of Supervisor of Wells pursuant to a public hearing, or pursuant to the voluntary pooling provisions of R 324.303.
 - (c) Pooled or communitized tracts may be developed according to approved alternative spacing and location plans. R 324.303.

Pooling

1. Authority to establish voluntary: Yes. R 324.303.
2. Authority to establish compulsory: Yes, public hearing is necessary. R 324.304.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes. R 324.201.
 - (b) Seismic drilling? Yes, for holes 50' or deeper and penetrating bedrock. Part 625, Mineral Wells of NREPA.
 - (c) Recompletion? Yes. Deepening R 324.206 and R 324.420; Rework R 324.511.
 - (d) Plugging and abandoning? Yes. R 324.901.
2. Permit fee:
 - (a) Drilling: \$300. Sec. 61525 of NREPA.
 - (b) Seismic drilling: \$500.00 for individual test wells. Blanket test permits (50' - 250') follow a permit fee schedule.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes. R 324.418, R 324.419, R 324.421, R 324.511, and R 324.902(10).

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? When the hole is intentionally directionally drilled. R 324.421.
 - (b) Filing of survey required? Yes. R 324.421.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes. R 324.408.
 - (b) Production casing: Yes. R 324.410.
2. Minimum amount of cement required:
 - (a) Surface casing: Circulate to surface. R 324.408.
 - (b) Intermediate and Production casing: Varies on formation and depth. R 324.411, 413.
 - (c) Setting time: 12 hour minimum. R 324.411.
3. Tubing requirements: All wells shall run tubing on completion. For certain conditions, exceptions may be granted.
 - (a) Oil wells: Yes. R 324.507.
 - (b) Gas wells: Yes. R 324.507. Gas storage wells are exempt.

Drilling and Completion

1. Drilling report required: Yes. R 324.418 (a).
 - (a) Time Limit: Within 60 days after completion of drilling. R 324.418 (a).
2. Completion report required: Yes. R 324.418 (b).
 - (a) Time limit: Within 60 days after well completion operations. R 324.418 (b).
 - (b) Where submitted: Supervisor of Wells, Office of Geological Survey, Department of Environmental Quality, P. O. Box 30256, Lansing MI 48909.
3. Well logs required to be filed: Yes. R 324.419.
 - (a) Time limit: Within 30 days after conducting the logging run. R 324.419.
 - (b) Where submitted: Supervisor of Wells, address above.
 - (c) Confidential time period: If requested by letter. R 324.416 provides for 90 days after drilling completion.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
4. Multiple completion regulation: Yes. R 324.508.
 - (a) Approval obtained: Upon written application and approval of Supervisor of Wells.
5. Commingling in well bore: Yes. R 324.509.
 - (a) Approval obtained: Upon written application and approval of Supervisor of Wells.

Oil Production

1. Definition of an oil well: A well that produces economic quantities of liquid hydrocarbon that is in the liquid state in the reservoir.
2. Potential tests required: Yes. R 324.606.
 - (a) Time interval: Commenced within 10 days after completion.
 - (b) Witness required: Rarely but representative of the Supervisor of Wells may if he wishes.
3. Statewide allowable: No.
 - (a) Pool allowable: The Supervisor of Wells may set a pool allowable if required to prevent waste and after a public hearing. Oil and/or gas allowable can vary for each reservoir. Section 61506, 61512 of NREPA; R 324.601.
 - (b) Well allowable: The Supervisor of Wells may set a well allowable if required to prevent waste and after a public hearing. Section 61506, 61512, 61513 of NREPA; R 324.601.

- (c) Exempt allowable: Yes. If a well location exception is granted the well allowable maybe reduced. Discovery wells may get a full allowable in an offspot location. Section 61513 of NREPA; R 324.301.
- 4. Maximum gas-oil ratio: The Supervisor of Wells may establish efficient gas-oil ratios if required to prevent waste and after a public hearing. Section 61506 of NREPA; R 324.601.
 - (a) Provision for limiting gas-oil ratio: Yes. The Supervisor of Wells may set oil or gas allowables on basis of gas-oil ratio for specific fields, after public hearing. Section 61506, 61512, 61513 of NREPA; R 324.601.
 - (b) Exception to limiting gas-oil ratio:
- 5. Bottom-hole pressure test reports required: Supervisor of Wells may require for specific reservoir. R 324.609.
 - (a) Periodical bottom-hole pressure surveys: Yes, for specified reservoirs.
- 6. Commingling oil and/or gas in common facilities: Yes, with approval of Supervisor of Wells. Requires facility details, and schematic drawing. Each well's production must be individually measured and compared to and balanced with actual sales. All details are to be reported on forms provided. R 324.510.
- 7. Measurement involving meters: Yes. R 324.510.
- 8. Production reports: All wells.
 - (a) By lease: Yes. R 324.610, R 324.612, or Supervisor of Wells Order.
 - (b) By well: Yes. R 324.610, R 324.612, or Supervisor of Wells Order.
 - (c) Time limit: 45 days following production month.

Gas Production

- 1. Definition of a gas well: A well that produces economic quantities of hydrocarbons that are in the gaseous state in the reservoir.
- 2. Pressure base 14.73 psia @ 60 degrees F.
- 3. Initial potential tests: Yes. AOF test (1 or 4 point).
 - (a) Time interval: Before pipeline connection permit is permanently issued.
 - (b) Witness required: Rarely.
- 4. Statewide allowable: Yes. 17 1/2% of AOF for single well reservoirs.
 - (a) Pool allowable: Yes. When transmission lines are running at capacity and curtailment is required.
 - (b) Well allowable: Yes. Proration allowable (when more than one well is in reservoir) is based on amount of pay under the drilling unit (90% generally) and absolute open flow test (10% generally).
 - (c) Exempt allowable: Yes. Low potential wells have a minimum allowable.
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: Yes.

6. Commingling of gas in common facilities: Yes, with approval of Supervisor of Wells. Requires facility details and schematic drawing. Each well's production must be individually measured and compared to and balanced with actual sales. All details are to be reported on forms provided. R 324.510.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: Yes, if pooled or unitized.
 - (b) By well: Yes.
 - (c) Time limit: 45 days following production month.

Water Disposal

1. State agencies that control disposal of produced salt water: Office of Geological Survey, Department of Environmental Quality. Section 61506 of NREPA; R 324.801 to R 324.808.

Unitization

1. Unitization of all or part of a pool or common source of supply for secondary or enhanced recovery: Yes. Part 617, Unitization, of NREPA.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization by one of the following: (Section 61706.).
 - (a) Persons liable for 75% of costs and owners of 75% of royalty production.
 - (b) Persons entitled to 75% of all production proceeds and owners of 50% of royalty production.
 - (c) Persons entitled to 90% of all production.

Taxation

Gas severance tax = 5.0%
 Gas ad valorem tax = 0.0%
 Total gas tax burden = 5.0%

Oil severance tax = 6.6%
 Oil ad valorem tax = 0.0%
 Total oil tax burden = 6.6%

1. Tax collecting agency: Department of Treasury, Customer Contract Division, Lansing, MI 48922.
2. How tax is computed:
 - (a) Michigan's gas severance tax is 5%. The oil severance tax is 6.6%.
 - (b) In addition to the severance tax there is a surveillance fee imposed to cover regulatory costs. The fee is set at a 1% maximum.
 - (c) The producer or purchaser pays severance tax on the gross cash market value of the gas and oil produced during the preceding month, computed at the wellhead, exclusive of the production attributable to the State, the United States, or a political subdivision of the State of United States. In addition, producers pay a surveillance fee on the gross cash

market value of the gas and oil to cover costs of state regulation. The fee is set in an amount calculated to cover the regulatory costs for the upcoming year, with a maximum rate of one percent.

3. Exemptions or exceptions: The severance tax on a stripper oil well is reduced to 4.0%.
4. Name of tax: Severance.
5. Statutory citation: Act 451 PA of 1994, Section 61524; Act 48 PA of 1929, Sec. 3, 14.

Land Leasing Information

1. Leasing Method: Competitive public auction.
2. Notice Method: At least once in a newspaper where the lands are situated not less than 10 days before the sale.
3. Minimum bidding \$ (per acre): \$13.00.
4. Qualification of the bidder: No specific qualification - any person.
5. State Statutes: Section 324.502 of the NREPA; Administrative Rules R 299.8102 – 299.8107.
6. Maximum acres: 160 acres.
7. Contact: Thomas Wellman
wellmant@michigan.gov
 Phone: (517) 373-7666

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environmental Quality
 For NORM materials associated with well plugging: Office of Geological Survey, P.O. Box 30256, Lansing, MI 48909.
 Phone: (517) 241-1548, Fax: (517) 241-1601.
 For other NORM materials: Waste and Hazardous Materials Division, P.O. Box 30630, Lansing, MI 48909-8130.
 Phone: (517) 335-8204, Fax: (517) 335-8706.
2. Relevant Statute/Regulations:
 For NORM materials associated with well plugging: Special Order of the Supervisor of Wells/Supervisor of Mineral Wells, Issued 11/3/1992.
 For other NORM materials: Act 368, P.A. 1978 as amended. The associated administrative rules (Michigan's Ionizing Radiation Rules) have not yet been revised to specifically address NORM concerns related to oil and gas production. Cleanup and Disposal Guidelines for Sites Contaminated with Radium-226 (Guidelines) are applicable.
3. Scope: Special Order deals with approved method for plugging wells in which NORM contamination exists on downhole equipment or is generated during plugging operations.
4. Licensing: None required.
5. Cleaning Equipment: None specified.
6. Disposal of Waste:
 NORM-contaminated tubulars may be reinserted into the well bore from which it was taken. Soils and other materials contaminated with NORM during plugging may be disposed of by insertion into the well being plugged.
 Bulk waste with a radium-226 concentration not exceeding 50 picocuries per gram, averaged over any single shipment, can be disposed of in a Type II solid waste landfill. The maximum radium-226 concentration within any single shipment must not exceed 100 picocuries per gram. Waste materials with radium-226 in concentrations above 50 picocuries per

gram must be disposed of at a licensed radioactive waste disposal facility.

7. Subsequent Use of Equipment: If NORM-contaminated equipment is not reinserted, it may be stored, reused, or recycled following applicable state and federal government regulations.
8. Subsequent Use of Materials: As for equipment above.
9. Release/Sale of NORM-Contaminated Land: If release is for *unrestricted* use, the Guidelines will be used to determine acceptable levels of residual contamination of radium-226. If release under certain restrictions may be appropriate, the Department will review specific site proposals for other release limits using the methodology for dose assessment in NUREG/CR-5512, Vol. 1 (U.S. Nuclear Regulatory Commission, October 1992). Restricted use release will not be approved if the maximum individual total effect dose equivalent can exceed 100 millirem per year under a reasonable worst-case scenario. Each specific site remediation proposal involving restricted use must include an *As Low as Reasonably Achievable* analysis.
10. Projected Volume of stored NORM in the State: Not applicable.
11. Respondent: Ray Vugrinovich (Office of Geological Survey), David Minnaar (Waste and Hazardous Materials Division).

MISSISSIPPI

Administration

1. State agency: State Oil and Gas Board, 500 Greymont Avenue, Suite E, Jackson, MS 39202-3446. Phone (601) 354-7114.
2. Docketing procedure: (a) Regular monthly meetings are held by the Board on the third Wednesday of each month. (b) Upon receipt of a proper request for hearing, by written petition or application, the Board shall call a hearing within 30 days and must take action with regard to the subject matter within 30 days after the conclusion of the hearing provided all required forms and data have been filed. Prehearing exhibits must be filed at least 9 days prior to the hearing.
 - (a) Emergency orders: Emergency order may be entered by the Board, on good cause shown, without notice and hearing, but the order is valid for a period of 45 days only and a hearing must be held, after notice, within that time.
 - (b) Notice: Twenty days prior to the regularly scheduled hearing date by the party who files the petition, or in action initiated by the Board, the agency. Thirty days for force pooling with risk penalties. All notices are signed by the State Oil and Gas Supervisor.

Bond

1. Compliance bond required: Yes; for new permits to drill and for transfer of permits. Statewide Rule 4.
2. Conditions of bond: Statewide Rule 4.
 - (a) Amount per well: \$10,000 {0' - 10,000'}, \$15,000 {10,001' - 16,000'}, \$30,000 (16,001' - 20,000'}, \$50,000 {20,001' or more}.
 - (b) Amount of blanket bond: \$100,000.

Spacing

1. Spacing requirements: Yes. Statewide Rules 7 and 8.
 - (a) Density: Oil well - 40 acres above 12,000 ft. and 80 or 160 acres below 12,000 ft. Gas well - 320 acres above 12,000 ft. and 640 acres below 12,000 ft.
 - (b) Lineal: Oil well - Statewide Rule 7. Gas well - Statewide Rule 8, unless special field rules authorize exception.
2. Exceptions: Yes. Statewide Rule 9.
 - (a) Basis: Either by adoption of Special Field Rules, which take precedence over State-wide Rules, or by request for exception to either.
 - (b) Approval: By notice and hearing before the State Oil and Gas Board.

Pooling

1. Authority to establish voluntary: Yes. Section 53-3-7.
2. Authority to establish compulsory: Yes. Section 53-3-7, 1972 Code.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes. Statewide Rule 4.
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes. Statewide Rule 4 (h) & 25.
 - (d) Plugging and abandoning: Yes. Statewide Rules 27 & 28.
 - (e) Change of operator: Yes. Statewide Rule 5.
2. Permit fee:
 - (a) Drilling: \$600, \$600 SWDW. (Class II Wells, UIC) Statewide Rule 4.
 - (b) Seismic drilling: No.
 - (c) Recompletion: \$100. Statewide Rule 4.
 - (d) Plugging and abandoning: No.
 - (e) Change of operator: \$100. Statewide Rule 5.
3. Require filing report of work performed: Yes, Statewide Rule 23 and (Rule 28B(3d)).

Vertical Deviation

1. Regulation requirement: Yes, Statewide Rule 14.
 - (a) When is directional survey necessary? Intentionally deviated wells, and all producible wells drilled which are an exception to the spacing rules under Statewide Rule 9 shall have directional surveys made to the total depth of the hole before setting the final string of casing. A certified copy of such directional survey shall be filed with the Board by the operator within 30 days from the making there-of. This requirement may be waived by the Supervisor, with the concurrence of the Chief Engineer, upon acceptable proof filed by the operator, whether by inclination survey or otherwise, that the bottom-hole location did not cross any unit boundaries.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes, based on well total depth. Statewide Rule 11.
 - (b) Production casing: Statewide Rule 12. To a sufficient depth adequately to protect the oil or gas bearing pool.
2. Minimum amount of cement required:
 - (a) Surface casing: Statewide Rule 11, 500 sacks of cement or circulated to surface.
 - (b) Production casing: Statewide Rule 12, 500 feet above casing shoe.

- (c) Setting time: Surface casing - 12 hours and production casing - 24 hours.
- 3. Tubing requirements: Statewide Rule 18.
 - (a) Oil wells: Each flowing oil well is limited to a maximum of 2 1/2-inch tubing.
 - (b) Gas wells: Gas wells are limited to 4-inch tubing.

Completion

- 1. Completion report required: Statewide Rule 23.
 - (a) Time limit: Within 6 months for Stratigraphic test; all others within 30 days after completion or recompletion.
 - (b) Where submitted: State Oil and Gas Board, 500 Greymont Avenue, Suite E, Jackson, MS 39202-3446.
- 2. Well logs required to be filed: Statewide Rule 24.
 - (a) Time limit: Within 6 months for Stratigraphic test; all others within 30 days after completion or within 60 days from logging date which ever is the earliest.
 - (b) Where submitted: State Oil and Gas Board, 500 Greymont Avenue, Suite E, Jackson, MS 39202-3446.
 - (c) Confidential time period: If so requested. Six months. Eighteen months for strat tests. May be extended an additional six months by the Supervisor and an additional year by the Board, after notice and hearing.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes, microfiche file with index.
- 3. Multiple completion regulation: Statewide Rule 15.
 - (a) Approval obtained: After notice and hearing before State Oil and Gas Board.
- 4. Commingling in well bore: Statewide Rule 15.
 - (a) Approval obtained: After notice and hearing before State Oil and Gas Board.

Oil Production

- 1. Definition of an oil well: Oil well shall mean any well capable of producing oil and which is not a gas well as defined herein.
- 2. Potential tests required: Statewide Rule 41.
 - (a) Time interval: N/A.
 - (b) Witness required: Not required.
- 3. Statewide allowable: No.
 - (a) Pool allowable: No, except in unitized pools.
 - (b) Well allowable: Statewide Rule 35, according to depth of producing interval, or MER.

- (c) Exempt allowable: Yes, discovery well of pool may produce at an unrestricted rate until cost of drilling and completing is recovered. Section 53-1-17, Miss. Code of 1972.
- 4. Maximum gas-oil ratio: 2,000-1. Statewide Rule 40.
 - (a) Provision for limiting gas-oil ratio: Yes. Statewide Rule 40.
 - (b) Exception to limiting gas-oil ratio: Yes, if authorized by the Board after notice and hearing.
- 5. Bottom-hole pressure test reports required: Statewide Rule 38.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: Statewide Rule 21A.
- 7. Measurement involving meters: Statewide Rule 21C.
- 8. Production reports: Statewide Rule 42.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time Limit: First day of the second month following the month for which production is reported.

Gas Production

- 1. Definition of a gas well: Gas well shall mean any well the production from which is predominantly gas or condensate, or both.
- 2. Pressure base 15.025 psia @ 60 degrees F. Statewide Rule 2 (h).
- 3. Initial potential tests: Statewide Rule 41.
 - (a) Time interval: N/A.
 - (b) Witness required: Not required.
- 4. Statewide allowable: No.
 - (a) Pool allowable: Statewide Rule 34.
 - (b) Well allowable: Yes, the pool allowable is allocated to wells based on maximum efficient rate of production from the pool. Statewide Rule 34.
 - (c) Exempt allowable: Yes. Discovery well of pool may produce at an unrestricted rate until cost of drilling and completing is recovered. Section 53-1-17, Miss. Code of 1972.
- 5. Bottom-hole pressure test reports required: Statewide Rule 38.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: No.
- 7. Measurement involving meters: Statewide Rule 21.
- 8. Production reports:

- (a) By lease: No.
- (b) By well: Yes. Statewide Rule 42.
- (c) Time limit: First day of the second month following the month for which production is reported.

Water Disposal

1. State agencies that control disposal of produced salt water: Regulatory agency (State Oil and Gas Board). Federal Underground Injection Control (UIC) Program (Safe Drinking Water Act) for Class II wells has been assigned to the State Oil and Gas Board. Bureau of Pollution Control will regulate industrial waste injection wells.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. Section 53-3-101, Miss. Code of 1972.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 75%.
 - (b) Royalty interest: 75%.

Taxation

Gas severance tax = 6.0%
 Gas ad valorem tax = 0.0%
 Gas Maintenance tax = 0.5 cents per mcf
 Total gas tax burden = 6.0% + .05 cents per mcf

Oil severance tax = 6.0%
 Oil ad valorem tax = 0.0%
 Oil Maintenance tax = 4.4 cents per barrel
 Total oil tax burden = 6.0% + 4.4 cents per barrel

1. Tax collecting agency: Severance tax - Mississippi State Tax Commission, P. O. Box 1033, Jackson, MS 39215. Maintenance Tax Assessments - State Oil and Gas Board, 500 Greymont Avenue, Suite E, Jackson, MS 39202-3446.
2. How tax is computed: Gas severance tax is 6% of the value of the production, at the mouth of the well. The maintenance tax assessments for gas are computed as 0.5 cents per MCF of gas. Oil severance tax is 6% of the value of the production, at the mouth of the well. The maintenance tax assessments for oil are 4.4 cents per barrel of oil. A severance tax return must be filed on or before the 25th of the month following the month of production.
3. Exemptions or exceptions:
 - (a) Wells completed after April 1, 1994, that use an approved enhanced oil recovery method receives a three percent (3%) reduced rate.
 - (b) To receive exempt status, a written request must be submitted to the Mississippi Oil and Gas Board.
4. Name of tax: Severance:
5. Statutory citation: Gas Severance Tax 27-25-703, Oil Severance Tax 27-25-503, Maintenance Tax Assessments 53-1-73.

State Land Leasing Information

1. Leasing Method: Negotiation bid and advertisement sealed bids - offshore: often use an advertisement sealed bids.
2. Notice Method: Advertisement in a Jackson paper, Southeastern Oil Review, and newspaper in the county where the

activities occur.

3. Minimum bidding \$ (per acre): \$2.00 per acre, 3/16 of Royalty - mostly advertise the minimum bidding amount on the case by case.
4. Qualification of the bidder: Any person can submit bids - residency is not required.
5. State Statutes: MS ST §29-7-3
6. Maximum acres: Offshore - 1/2 block.
7. Contact: Jack Moody
Phone: (601) 961-5522
E-mail: jack_moody@deq.state.ms.us

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Health, Division of Radioactive Health, Radioactive Materials Branch, P.O. Box 1700, Jackson, MS 39215. Phone: (601) 354-6167, Fax: (601) 354-6687.
2. Relevant Statute/Regulations: Mississippi State Board of Health Regulations for Control of Radiation, Section N.
3. Scope: Mississippi Legislature gave NORM regulatory action to the State Oil and Gas Board in 1995.
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Respondent: B. J. Smith
12. Regulating Agency: Mississippi State Oil and Gas Board for E&P generated NORM, 500 Greymont Ave., Ste. E, Jackson, MS 39202. Phone: (601) 354-6474, Fax: (601) 354-6873.
13. Relevant Statute/Regulations: Rule 68. Disposal of NORM. State Code 53-1-3 (t)
Rule 69. Control of NORM. State Code 53-1-17 (7)
14. Scope: Applies to NORM derived from exploration and production activities at facilities which on or after 7/1/95 were permitted by the State Oil and Gas Board, and which on some date were active or inactive.
15. Licensing: None. Site survey required on all sites with results reported on Form 21.
16. Cleaning Equipment: Required for "release for unrestricted use" but not regulated.
17. Disposal of Waste: Permitted under Rule 68 for disposal by landspreading, in wells being plugged and abandoned, or offsite at a licensed low level radioactive waste or NORM disposal facility.
18. Subsequent Use of Equipment: No restrictions if transferred to another producer. Radiation limits if released for unrestricted use.

19. Subsequent Use of Materials: No restrictions if used by another oil and gas producer.
20. Release/Sale of NORM-Contaminated Land: No restrictions if transferred to another producer. Radiation limits for release for unrestricted use.
21. Projected Volume of stored NORM in the State: N/A.
22. Respondent: W. Kent Ford

MISSOURI

Administration

1. State agency: State Oil and Gas Council administered through the Geological Survey Program, P. O. Box 250, Rolla, MO 65402. Phone (573) 368-2143.
2. Docketing procedure: Public hearing held at such time and place as may be prescribed by the Council.
 - (a) Emergency orders: By Chapter 259.140 RSMo. Council is authorized to issue an emergency order without hearing which shall be effective upon promulgation. Effective for no more than 15 days.
 - (b) Notice: 10 days. State Oil and Gas Council. Chapter 259.140 RSMo.

Bond

1. Compliance bond required: Yes. 10 CSR 50-2.020 - Surety Bond, Certificate of Deposit, or Letter of Credit. Chapter 259.070 (d) RSMo.
2. Conditions of bond: Form OGC-2. Bond is the obligation of the owner of producing well or wells or proposals to drill for oil or gas or for stratigraphic purposes.
 - (a) Amount per well: 10 CSR 50-2.020.

<u>Depth (ft.)</u>	<u>Amount</u>	<u>Depth (ft.)</u>	<u>Amount</u>
0- 500	\$1,000	2,001-5,000	\$4,000
501-1,000	2,000	5,001----	4,000
1,001-2,000	3,000		Plus \$1/ft. beyond 5,001

- (b) Amount of blanket bond: 10 CSR 50-2.020.

<u>Depth (ft.)</u>	<u>Amount</u>	<u>Number of Unplugged Wells/Bond</u>
0- 800	\$20,000	50
801-1,200	30,000	15

Spacing

1. Spacing requirements: Yes.
 - (a) Density: 10 CSR 50-2-070

Oil - 40 acres may be excepted if less than 1200 ft. deep to producing formation.

Gas - 640 acres may be excepted if less than 1500 ft. deep to producing formation.
 - (b) Lineal: 165 feet from lease boundary or property line for an oil well. 234 feet for a gas well. 10 CSR 50-2.070. Non-commercial gas well 165 feet from lease line.
2. Exceptions: Yes. 10 CSR 50-2.070.
 - (a) Basis: To protect against offset drainage from wells drilled prior to enactment of Chapter 259 RSMo. and special project development.

- (b) Approval: Upon application to the State Geologist who is administrator. 10 CSR 50-2.070.

Pooling

1. Authority to establish voluntary: 10 CSR 50-4.010.
2. Authority to establish compulsory: 10 CSR 50-5.010.

Drilling Permit

Change in legislation allowing Global Positioning System well location in lieu of Registered Land Survey.

The Oil and Gas Council recently authorized an amendment to the rules that allows for oil and gas well locations to be determined by a Global Positioning System (GPS) receiver. The rule allows the use of GPS receivers as an alternative to standard land surveying methodologies. Determining the location of oil and gas wells with a GPS unit will be easier, quicker, and less costly thereby allowing the oil and gas industry to reduce certain costs and operate more efficiently.

<http://www.sos.mo.gov/adrules/csr/current/10csr/10c50-2.pdf>

10CSR 50-2.030 (2) (A) *Amended: Filed, Sept. 15, 2006, effective April 30, 2007.*

1. Require permits for:
 - (a) Drilling a producing or service well? Yes. 10 CSR 50-2.030.
 - (b) Seismic drilling: Not specifically stated under oil and gas law, may be required under water well regulations, 10 CSR 23-6.010.
 - (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes. 10 CSR 50-2.060.
2. Permit fee:
 - (a) Drilling: None.
 - (b) Seismic drilling: Not under oil and gas law, but may be required under water well regulations, 10 CSR 23-6.010.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes. 10 CSR 50-2.050. OGC-5 Drilling Report.

Vertical Deviation

1. Regulation requirement: No.
 - (a) When is directional survey necessary? Never.
 - (b) Filing of survey required? If taken by operator. 10 CSR 50-2.050.

Casing and Tubing

1. Minimum amount required: 10 CSR 50-2.040.
 - (a) Surface casing: Yes.

- (b) Production casing: No.
- 2. Minimum amount of cement required:
 - (a) Surface casing: Yes, to surface.
 - (b) Production casing: As necessary to protect all water, oil or gas bearing strata, etc.
 - (c) Setting time: Yes. Minimum 6 hours, maximum 24 hours depending on amount of CaCl_2 .
- 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

- 1. Completion report required: Yes. 10 CSR 50-2.050.
 - (a) Time limit: 30 days.
 - (b) Where submitted: To the State Geologist, P.O. Box 250, Rolla, MO 65402.
- 2. Well logs required to be filed: Yes. 10 CSR 50-2.050.
 - (a) Time limit: 30 days.
 - (b) Where submitted: To the State Geologist, P.O. Box 250, Rolla, MO 65402.
 - (c) Confidential time period: Yes. One year if requested.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes.
- 3. Multiple completion regulation: No.
 - (a) Approval obtained: No.
- 4. Commingling in well bore: No.
 - (a) Approval obtained: No.

Oil Production

- 1. Definition of an oil well: Crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas other than gas produced in association with oil and commonly known as casinghead gas. 10 CSR 50-1.030.
- 2. Potential tests required: No.
 - (a) Time interval: No.
 - (b) Witness required: No.
- 3. Statewide allowable: No. However, Council has statutory authority. Chapter 259.090 RSMo.

- (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Yes. Chapter 259.70 RSMo.
 - (b) Exception to limiting gas-oil ratio: No.
 5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
 6. Commingling oil in common facilities: No.
 7. Measurement involving meters: No.
 8. Production reports: 10 CSR 50-2.080.
 - (a) By lease: Yes.
 - (b) By well: Yes, if requested.
 - (c) Time limit: 30 days.

Gas Production

1. Definition of a gas well: All natural gas and all other fluid hydrocarbons, which are produced at the wellhead and not defined as oil. 10 CSR 50-1.030.
2. Pressure base Not stated psia @ ____ degrees F.
3. Initial potential tests: No.
 - (a) Time interval: No.
 - (b) Witness required: No.
4. Statewide allowable: No. (Council has authority.) Chapter 259.090 RSMo.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: No.
7. Measurements involving meters: No.
8. Production reports: 10 CSR 50-2.080.

- (a) By lease: Yes.
- (b) By well: Yes, if requested.
- (c) Time limit: 30 days.

Water Disposal

- 1. State agencies that control disposal of produced salt water: 10 CSR 50-2.090. State Oil and Gas Council.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source supply. Yes. 10 CSR 50-5.010
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization. Chapter 259.120 RSMo.
 - (a) Working interest: 75%.
 - (b) Royalty interest: 75%.

Taxation

There is no state tax levied on oil and gas production in Missouri. Chapter 259.220 RSMo.

Land Leasing Information

No regulations at this time.

Naturally Occurring Radioactive Material (NORM)

- 1. Regulating Agency: Missouri Department of Natural Resources, Division of Environmental Quality, Solid Water Program, P.O. Box 176, Jefferson City, MO 65102. Phone: (573) 751-5401, Fax: (573) 526-3902.
- 2. Relevant Statute/Regulations: 10 CSR 50-2.090. Solid Waste regulations deal with NORM. There is no oil or gas production that needs NORM regulation.
- 3. Scope:
- 4. Licensing:
- 5. Cleaning Equipment:
- 6. Disposal of Waste:
- 7. Subsequent Use of Equipment:
- 8. Subsequent Use of Materials:
- 9. Release/Sale of NORM-Contaminated Land:
- 10. Projected Volume of stored NORM in the State:
- 11. Respondent: Chris Nagel DEQ

Jeff Jaquess - Oil and Gas

MONTANA

Administration

1. State agency: Board of Oil and Gas Conservation, P.O. Box 217, Helena, MT 59624. Phone (406) 449-2622. Technical Office: 2535 St. Johns Avenue, Billings, MT 59102, Phone (406) 656-0040. Northern Field Office: 218 Main Street, P.O. Box 690, Shelby, MT 59474, Phone (406) 434-2422.
2. Docketing procedure: Upon receipt of petition concerning any matter within the jurisdiction of the Board, the Board will promptly fix a date for hearing and cause notice of the hearing to be given. The Board must enter its order within 30 days after its hearing.
 - (a) Emergency orders: Sections 82-11-141, 82-11-151, Montana Code Annotated (MCA). Yes, when an emergency requiring immediate action is found to exist, the Board is authorized to issue an emergency order without advance notice or hearing, which shall be effective upon promulgation. An emergency order may not remain in effect beyond the next regular meeting of the Board.
 - (b) Notice: An order or amendment thereof may not be made by the Board without a public hearing upon at least ten (10) days notice. At least 20 days prior to the public hearing, a person who applies for a well spacing unit or who applies to pool all interests in a well spacing unit shall cause written notice to be served upon the record owners of the oil and gas leasehold interests sought to be spaced or pooled.

Bond

1. Compliance bond required: Yes. Rule 36.22.1308.
2. Conditions of bond: Conditioned upon proper plugging and abandonment of a well and restoration of the surface to its original contours.
 - (a) Amount per well: \$1500 (2000 feet or less); \$5,000 (3500 feet or less); \$10,000 greater than 3500 feet.
 - (b) Amount of blanket bond: \$50,000.

May be increased to \$3,000, \$10,000, \$20,000, or \$100,000 respectively at the Board's discretion.

Spacing

1. Spacing requirements: Yes. Rule 36.22.702.
 - (a) Density: 40 acres for oil wells less than 6,000' deep; 160 acres for wells from 6,001' to 11,000'; 320 acres for wells deeper than 11,000'. For a gas well, 640 acres.
 - (b) Lineal: 330' from legal subdivision line for wells less than 6,000'; 660' from quarter section lines for wells 6,001 to 11,000'; 660' from drilling unit boundaries for wells below 11,000'. For gas wells, 990' from governmental section lines.
2. Exceptions: Yes, Rule 36.22.702(1).
 - (a) Basis: For wildcat wells less than 6,000', wells may be moved a maximum of 75' closer to quarter-quarter section line, and wells between 6,000' to 11,000' may be moved a maximum for 150' closer to quarter section lines in extremely rough terrain where it is impractical to move in any other direction but only after inspection by the Board representative and subsequent approval by the petroleum engineer or his authorized agent. No tolerance for wells below 11,000' nor for gas wells.
 - (b) The Board may also grant exceptions to protect correlative rights or to prevent waste. Section 82-11-124, MCA.

- (c) Approval: Administrative approval for tolerances described in (a). Exceptions beyond those tolerances in (a) require notice and hearing.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes. Rule 36.22.601.
 - (b) Seismic drilling: Permit is issued by County Clerk and Recorder. Rule 36.22.503; Section 82-1-105, MCA.
 - (c) Recompletion: Yes. Rule 36.22.601(2).
 - (d) Plugging and abandoning. Yes. Rule 36.22.1301.
2. Permit fee:
 - (a) Drilling: Fee is based on depths as follows: 0 - 3,500, \$25; 3501' - 7,000', \$75; 7,001 - below, \$150. Rule 36.22.603.
 - (b) Seismic drilling: \$5.00. Section 82-1-105(4), MCA.
 - (c) Plugging and abandoning: None.
3. Require filing report of work performed: Yes. Rule 36.22.1013.
4. Require publication of notice of intent to drill: Yes. If the proposed well or hole is not located within the boundaries of a delineated field for which, after public hearing, an order has been entered by the Board that drilling permits may issue for locations within that field without further public hearing, the applicant must cause publication of notice in a format prescribed by the Board in one issue of a newspaper in general circulation in Helena and a newspaper of general circulation in the county where the proposed well or hole is located. Proof of such publication in the form of a copy of the page on which the ad appears showing the ad and the date of publication or an affidavit of the publisher must be filed with the Board. Any party may demand in writing an opportunity to be heard within ten (10) days after the date of the publication of the notice. Rule 36.22.601.
5. Require notice to surface owner: Yes. Sections 82-10-503, 82-11-122, MCA.

Vertical Deviation

1. Regulation requirement: Yes, Rule 36.22.1003. Unless otherwise ordered by the Board upon hearing all wells shall be so drilled that the horizontal distance between the bottom of the hole and the location at the top of the hole shall be at all times at a practical minimum.
 - (a) When is directional survey necessary? When the intent is to direct the bottom of the hole away from the vertical, notice shall be filed with the Board and administrative approval obtained. Deviations to straighten the hole, sidetrack junk or correct mechanical difficulties need not be approved. Administrative approval for controlled directional drilling is not available where the proposed bottomhole location is not in compliance with applicable field or statewide well locations rules. Rule 36.22.1003.

- (b) Filing of survey required? Yes, within 30 days after completion of work.

Casing and Tubing

1. Minimum amount required: Rule 36.22.1001.
 - (a) Surface casing: Yes. Shall be run to reach a depth below all potable fresh water located at levels accessible for agricultural and domestic use.
 - (b) Production casing: No specific requirements.
2. Minimum amount of cement required: Rule 36.22.1001.
 - (a) Surface casing: Yes. Sufficient to circulate to surface.
 - (b) Production casing: No.
 - (c) Setting time: Yes, 8 hours before pressure testing. All cemented casing strings shall stand under pressure until the cement has reached a compressive strength of 300 pounds per square inch.
3. Tubing requirements: Rule 36.22.1206.
 - (a) Oil wells: Yes. All flowing oil wells shall be equipped with and producing through tubing unless the well is a dual completion.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes. Rule 36.22.1013.
 - (a) Time limit: Within 30 days after completion for field development wells, within six (6) months for wildcat wells, within three (3) years for stratigraphic test wells.
 - (b) Where submitted: Board of Oil and Gas Conservation, 2535 St. Johns Avenue, Billings, MT 59102 for wells drilled in Southern District; Board Field Office, Box 690, Shelby, MT 59474 for wells drilled in Northern District.
2. Well logs required to be filed: Yes. Rule 36.22.1013.
 - (a) Time limit: Within 30 days of completion for field development wells, within six (6) months of completion for exploratory wells, within three (3) years for completion for stratigraphic test wells.
 - (b) Where submitted: Two copies to the Board of Oil and Gas Conservation district office where the well is located (Billings or Shelby).
 - (c) Confidential time period: Operator may withhold filing of logs and completion information on exploratory wells for up to six (6) months after the completion date; information from stratigraphic test wells may be held confidential for three (3) years.
 - (d) Available for public use: Yes. Logs and other well information are available for public use in Billings for the entire state and in Shelby for the Northern district wells only.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes. Rule 36.22.1004 for dual completion.
 - (a) Approval obtained: By first notifying the Board on Form No. 2 and by notifying each offset operator in writing at

least 10 days prior to commencement and obtaining approval from the petroleum engineer or his authorized agent after such 10 days. If within such 10 days any offset operator shall file with the Board a written protest to the proposal, the matter shall be immediately set for hearing, after notice, and shall not be approved until permitted by order of the Board after such hearing.

4. Commingling in well bore: Yes. Rule 36.22.1208.
 - (a) Approval obtained: Must receive written permission from the Board, which may require at the discretion of the Board, notice and hearing.

Oil Production

1. Definition of an oil well: Any well capable of producing oil in paying quantities; not a gas well. Rule 36.22.302(33).
2. Potential tests required: Yes. Rule 36.22.1013.
 - (a) Time interval: Filed on prescribed form within 30 days following completion of field wells and 6 months following completion of wildcats.
 - (b) Witness required: No.
3. Statewide allowable: No.
 - (a) Pool allowable: Yes. The Board may set allowables for pools or wells when warranted to protect correlative rights or prevent waste. None in effect at this time.
 - (b) Well allowable: See (a).
 - (c) Exempt allowable: No provision.
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Yes. Rule 36.22.1216; Section 82-11-124(2), MCA. GOR's to be reported within 30 days after completion. May be limited after notice and hearing upon application.
 - (b) Exception to limiting gas-oil ratio: Yes.
5. Bottom-hole pressure test reports required. Rule 36.22.1214. Yes, within 30 days following completion, and reported on prescribed form within 20 days after test is made.
 - (a) Periodical bottom-hole pressure surveys: Subsequent tests may be required by the Board to provide adequate data for establishing the maximum efficiency rates of production (MER).
6. Commingling oil in common facilities: No provision.
7. Measurement involving meters: No provision.
8. Production reports: Rule 36.22.1242.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Filed on prescribed form on or before the last day of each month succeeding the month in which the production or taking occurs.

Gas Production

1. Definition of a gas well: Any well which produces natural gas only; or any well capable or producing gas in commercial quantities and also producing oil from the same common source of supply but not in commercial quantities; and any well classified as a gas well by the Board for any reason. Rule 36.22.302(27).
2. Pressure base 14.73 psia @ 60 degrees F. Rule 36.22.1218.
3. Initial potential tests: Yes. Rule 36.22.1013.
 - (a) Time interval: 30 days after completion for field wells; 6 months after completion for "wildcat" wells.
 - (b) Witness required: no.
4. Statewide allowable: No provision.
 - (a) Pool allowable: The Board has the authority to limit production when warranted to prevent waste and to protect correlative rights. Usually, operators only limit production in times of low market demand.
 - (b) Well allowable: See (a).
 - (c) Exempt allowable: No provision.
5. Bottom-hole pressure test reports required. Rule 36.22.1214. Yes, within 30 days following completion, and reported on prescribed form within 20 days after test is made.
 - (a) Periodical bottom-hole pressure surveys: Subsequent tests may be required by the Board to provide adequate data for establishing the maximum efficiency rate of production (MER).
6. Commingling oil in common facilities: No provision.
7. Measurement involving meters: Yes. Rule 36.22.1218.
8. Production reports: Rule 36.22.1242.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Filed on prescribed form on or before the last day of each month succeeding the month in which the production or taking occurs.

Water Disposal

1. State agencies that control disposal of produced salt water: Yes. Rule 36.22.1226. Controlled by Board of Oil and Gas Conservation.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. Sections 82-11-204, 205, 206, 207, and 208, MCA.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization: Yes. Section 82-11-207, MCA.
 - (a) Working interest: 80%.

- (b) Royalty interest: 80%.

Taxation

Gas severance tax = see chart below

Gas ad valorem tax = see chart below

Total gas tax burden = variable; see summary below

Oil severance tax = see chart below

Oil ad valorem tax = see chart below

Total oil tax burden = variable; see summary below

1. Tax collecting agency: Department of Revenue, Natural Resources and Corporation Tax Division, Mitchell Building, Helena, MT 59601.
2. How tax is computed:

Natural gas is taxed on the gross taxable value of production based on the type of well and type of production according to the following schedule for working interest and nonworking interest owners:

Natural gas production tax in Montana:		Working Interest	Nonworking Interest
(a) Primary Recovery Production:			
(1)	first twelve months of qualifying production:	0.8%	15.1%
(2)	after twelve months:		
(a)	pre-1999 wells:	15.1%	15.1%
(b)	post-1999 wells:	9.3%	15.1%
(b)	Stripper Natural Gas:	11.3%	15.1%
(c) Horizontally Completed Well Production:			
(1)	first 18 months:	0.8%	15.1%
(2)	next 18 months:	9.3%	15.1%

- The total gross value of natural gas produced and sold each quarter is determined by taking the total number of cubic feet of natural gas produced and sold each month as the average value at the mouth of the well during the month that the natural gas is produced and sold, as determined by the department.
- In computing the total number of cubic feet of gas produced and sold, the amount of gas used by the person in connection with the operation of the well must be deducted from the total.

Oil is taxed on the gross taxable value of production based on the type of well and type of production according to the following schedule for working and nonworking interest owners.

Oil production tax in Montana:		Working Interest	Nonworking Interest
(a) Primary Recovery Production:			
(1)	first twelve months of qualifying production:	0.8%	15.1%
(2)	after 12 months:		
(a)	pre-1999 wells:	12.8%	15.1%
(b)	post-1999 wells:	9.3%	15.1%
(b)	Stripper Oil Production:		

- | | | | | |
|-----|--|-------|-------|-------|
| (1) | first 1 through 10 a day production: | 5.8% | 15.1% | |
| (2) | more than 10 barrels a day production: | 9.3% | 15.1% | |
| (c) | Stripper Well Exemption Production: | 0.8% | 15.1% | |
| | Horizontally Completed Well Production: | | | |
| (1) | first 18 months of qualifying production: | 0.8% | 15.1% | |
| (2) | after 18 months: | | | |
| | (a) pre-1999 wells: | 12.8% | 15.1% | |
| | (b) post-1999 wells: | 9.3% | 15.1% | |
| (d) | Incremental Production: | | | |
| (1) | new or expanded secondary recovery production: | 8.8% | 15.1% | |
| (2) | new or expanded tertiary production: | | 6.1% | 15.1% |
| (e) | Horizontally Recompleted Well: | | | |
| (1) | first 18 months: | 5.8% | 15.1% | |
| (2) | after 18 months: | | | |
| | (a) pre-1999 wells: | 12.8% | 15.1% | |
| | (b) post-1999 wells: | 9.3% | 15.1% | |
3. Exemptions or exceptions: Exemptions for natural gas used by the operator in connection with his operations is exempt.
 4. Name of tax: Production Tax (ex-severance).
 5. Statutory citation: Production Tax (ex-severance): Sections 15-36-301 through 324, MCA.

Land Leasing Information

1. Leasing Method: Public auction - oral bidding.
2. Notice Method: Advertisement in three Montana newspapers, Montana Department of Natural Resources Web site, www.dnrc.state.mt.us/trust/mmbog.htm and Rocky Mountain Oil Journal.
3. Minimum bidding \$ (per acre): \$1.50 per acre, minimum bid is \$100.
4. Qualification of the bidder: Any person can submit bids. Corporations must be incorporated in Montana or licensed to do business in the state.
5. State Statutes:
6. Maximum acres: 1 section or 1 portion of 1 section
7. Contact: Barbara Hamburg
Phone: (406) 444-4561

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Montana Department of Public Health and Human Services.
2. Relevant Statute/Regulations: None; will be developing regulations within the next year, based on the CRCPD's state suggested regulations.
3. Scope:
4. Licensing:

5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Respondent: George Eicholtz

NEBRASKA

Administration

1. State agency: Nebraska Oil and Gas Conservation Commission, P. O. Box 399, Sidney, NE 69162. Phone (308) 254-6919. Web site <http://www.nogcc.ne.gov>
2. Docketing procedure: Hearings held on fourth Tuesday of each month. Application must be received 21 days prior to hearing date. Original and six copies must be filed.
 - (a) Emergency orders: Yes. Order is effective upon promulgation, but shall remain effective for no more than 20 days.
 - (b) Notice: 15 days. Applicant is responsible, in most cases, by certified mail and Commission by newspaper notice.

Bond

1. Compliance bond required: Yes. Rule 3.004.
2. Conditions of bond: Duty to comply with all laws of the state and the rules, regulations and orders of the Commission.
 - (a) Amount per well: \$5,000.
 - (b) Amount of blanket bond: \$25,000.

Spacing

1. Spacing requirements: Yes, unless accepted by public hearing. Rule 3.013.
 - (a) Density: 40 acres for oil or gas well.
 - (b) Lineal: No closer than 500 feet to 40-acre legal subdivision line for oil or gas, wells deeper the 2,500'. No closer than 300 feet to 40 acre legal subdivision for wells less than 2,500'.
2. Exceptions: Yes.
 - (a) Basis: Topographical, irregular sections or geological considerations.
 - (b) Approval: Administrative if all owners within 500 ft. of proposed well approve, or by public hearing. Production may be limited to protect correlative rights.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes. Rule 3.003.
 - (b) Seismic drilling? Yes. Rule 3.032.

- (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes.
2. Permit fee:
 - (a) Drilling: \$200. No fee for service well.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: \$100. - producer, none - dry hole. Rule 3.028.
 3. Require filing report of work performed: Yes. Rule 3.006 & 3.007.

Vertical Deviation

1. Regulation requirement: Yes. Rule 3.014.
 - (a) When is directional survey necessary? When necessary to insure protection of correlative rights.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Through fresh water zones.
 - (b) Production casing: No.
2. Minimum amount of cement required:
 - (a) Surface casing: Circulate.
 - (b) Production casing: No.
 - (c) Setting time: Yes. 500 psi compressive strength.
3. Tubing requirements
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes. Rule 3.006.
 - (a) Time limit: 30 days from logging date.
 - (b) Where submitted: Commission offices, Sidney, NE.
2. Well logs required to be filed: Yes. Rule 3.031.
 - (a) Time limit: 30 days from logging date.

- (b) Where submitted: Commission offices, Sidney, NE.
- (c) Confidential time period: Yes, not more than 12 months.
- (d) Available for public use: Yes.
- (e) Log catalog available: No.
- 3. Multiple completion regulation: Yes. Rule 3.017.
 - (a) Approval obtained: Application and public hearing.
- 4. Commingling in well bore: Yes. Rule 3.016.
 - (a) Approval obtained: Application and public hearing.

Oil Production

- 1. Definition of an oil well: A well from which the principal production at the wellhead is oil as defined in the Act. Rule 1.009.
- 2. Potential tests required: Yes.
 - (a) Time interval: 30 days or in accordance with special field rules.
 - (b) Witness required: No.
- 3. Statewide allowable: No.
 - (a) Pool allowable: Yes, based on M.E.R.
 - (b) Well allowable: Yes, based on M.E.R. or protection of correlative rights.
 - (c) Exempt allowable: No.
- 4. Maximum gas-oil ratio: Yes, to prevent waste only.
 - (a) Provision for limiting gas-oil ratio: Yes, to prevent waste.
 - (b) Exception to limiting gas-oil ratio: Yes.
- 5. Bottom-hole pressure test reports required: When required by special field rules.
 - (a) Periodical bottom-hole pressure surveys: See above.
- 6. Commingling oil in common facilities: Yes, providing production is metered or measured separately.
- 7. Measurement involving meters: To the extent that production be accurately measured.
- 8. Production reports: Yes.
 - (a) By lease: Yes.
 - (b) By well: Only by specific order.

- (c) Time limit: 25th day of month following production.

Gas Production

1. Definition of a gas well: The principal production of which at the wellhead is gas as defined in the Act. Rule 1(10).
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: 30 days.
 - (b) Witness required: No.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes, M.E.R. or ratable take.
 - (b) Well allowable: Yes, M.E.R. or ratable take.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: When required by special field rules.
6. Commingling of gas in common facilities: Yes, after application and public hearing.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: When required by special field rules.
 - (c) Time limit: 25th day of month following production.

Water Disposal

1. State agencies that control disposal of produced salt water: Oilfield waters handled by Oil and Gas Commission. Rule 4. Section 57-905 (4), Revised statutes. Chapter 4, underground injection. 3.022, produced water pits.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. Section 57-910, Revised statutes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 65%.
 - (b) Combined interest: 75%.

Taxation

State Taxes

County Taxes

Gas severance Tax = 3.0%
 Gas Ad Valorem = 0%
 Conservation Tax = 0.3%
 Total Current Tax = 3.3%

Real Estate @ Fair Market Value
 @ County's Mill Levies
 Personal Property, Tangible Equipment
 Located at Well and Tank Battery

Oil Severance Taxes
 Non-stripper = 3.0%
 Stripper = 2.0%
 Oil Ad Valorem = 0%
 Conservation Tax = 0.3%
 Total Current Tax = 2.3% to
 = 3.3%

Real Estate @ Fair Market Value
 @ County's Mill Levies
 Personal Property, Tangible Equipment
 Located at Well and Tank Battery

1. Tax collecting agency: Department of Revenue, P. O. Box 94818, Lincoln, NE 68509. As well as, various county treasurers.
2. How tax is computed: Severance tax is levied at the rate of three percent (3%) of the value of non-stripper oil and natural gas severed from the soil of the state. Stripper wells producing oil shall remit severance tax at the rate of two percent (2%). The first purchaser pays the tax if the oil or natural gas is sold in Nebraska, or by the person doing the severing if the oil or gas is sold outside Nebraska. The tax collected is identified as either coming from school lands or from all other lands. The entire amount is credited to the Severance Tax Fund.

The Severance Tax Administration Fund receives one percent of the gross severance tax receipts, excluding those receipts from tax derived from oil and natural gas severed from school lands. The balance of the Severance Tax Fund received from school lands is allocated to the Permanent School Fund. The balance of the Severance Tax Fund received from other than school lands is allocated as follows:

- (a) the Legislature may transfer an amount to be determined by the Legislature through the appropriations process up to \$300,000 for each year to the State Energy Office Cash Fund,
- (b) the Legislature may transfer an amount to be determined by the Legislature through the appropriations process up to \$30,000 for each year to the Governor's Policy Research Office for administration of the Municipal Natural Gas Regulation Revolving Loan Fund, and
- (c) on August 1, 2000, the State Treasurer shall transfer one hundred thousand dollars to a cash fund to be administratively created under the Legislative Council for the purpose of conducting the study authorized by subsection (5) of section 19-4617, and
- (d) the remainder shall be credited to the Permanent School Fund. Any funds transferred that are not expended by June 30, 2001 shall be credited to the Permanent School Fund.

There is also a conservation tax of 3 mills/dollar effective 6/01/2006. Counties also make oil and gas tax assessments that vary from county to county. Values are based upon "fair market value" of lease as determined by appraiser.

3. Exemptions or exceptions: Oil or gas as is used only in severing operations or for repressuring or recycling purposes is excluded from the gas severance tax. The interests of government units and Native American Indian tribes are exempt from the severance tax. Oil produced from stripper wells is subject to a severance tax of two percent, rather than three percent.
4. Statutory Citation: Section 57-701 through 57-714, Nebraska Revised Statutes.

Land Leasing Information

1. Leasing Method: Public auction - oral bidding.
 NOTE: file at the Board of Educational Lands and Funds
2. Notice Method: Public notice - placed in a publication two consecutive weeks in a legal newspaper, published in the

county where the land to be leased is situated.

3. Minimum bidding \$ (per acre): If the land is located in the county and there is no oil and gas production - \$1.00/acre bonus and 1/8 royalty; if the land is located in the county and there is oil and gas production - \$2.00/acre bonus and 1/6 royalty.
4. Qualification of the bidder: Any person who nominated and submitted the complete lease sale application with the minimum one (1) year rental fee.
5. State Statutes: NE ST
 - §23-3109
 - §23-3110
 - §57-220
6. Maximum acres: 640 acres per section
7. Contact: Laura Bahr-Frew
(402) 471 – 2014
Board of Educational Lands and Funds
nebrbelf@mail.state.ne.us

NOTE: Nebraska holds two (2) sales a year.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: HHS Regulation and Licensure, Public Health Assessment, Radioactive Material Program, P. O. Box 95007, Lincoln, NE 68509. Phone: (402) 471-2168.
2. Relevant Statute/Regulations: At the present time, Nebraska has not adopted specific NORM regulations. Occurrences of NORM problems are currently handled under the state's general regulations for the control of radiation.
3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Respondent: Brian Hearth

NEVADA

Administration

1. State agency: Nevada Commission on Mineral Resources, Division of Minerals, 400 W. King St., Suite 106, Carson City, NV 89703-4212. Phone (775) 684-7040, FAX (775) 684-7052.
2. Docketing procedure: The Division may act upon its own motion or upon the petition of any interested person concerning any matter within the jurisdiction to set a date for hearing without undue delay. The Division shall enter its order within 30 days after the hearing.
 - (a) Emergency orders: Yes. The Division may issue emergency orders without notice and hearing. Emergency rule, regulation or order shall remain in force no longer than 15 days from its effective date.
 - (b) Notice: No less than 10 days prior to the date of the hearing. The Administrator of the Division of Minerals is responsible to give notice.

Bond

1. Compliance bond required: Yes, a bond of not less than \$10,000 for individual well bonds and not less than \$50,000 for statewide drilling bond is required for all drilling in Nevada. The Division will accept a federal bond in a form and amount equivalent to the form and amount approved by the Division.
2. Conditions of bond: Sufficient surety conditioned for the performance of the duty to plug each dry or abandoned well or the repair of wells causing waste.
 - (a) Amount per well: \$10,000.
 - (b) Amount of blanket bond: \$50,000.

Spacing

1. Spacing requirements: Yes.
 - (a) *Density:

Oil well - 5,000' or less: 40 acres - not less than 330' from boundary of quarter-quarter section.

Oil well - more than 5,000': 160 acres - not less than 330' from boundary of quarter section.

Gas well - 5,000' or less: 160 acres - not less than 660' from boundary of quarter section.

Gas well - more than 5,000': 640 acres - not less than 990' from boundary of section.
 - (b) Lineal: No provision. Determined after hearing.

*The spacing requirements do not apply to federal units, working interest agreements, and areas subject to existing orders.
2. Exceptions: Yes.
 - (a) Basis: Protection of correlative rights of lessees, location may be nonproductive, or topographical conditions.
 - (b) Approval: By hearing after proper notice and order issued by the Division.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes, Application for Permit to Drill an Oil or Gas Well.
 - (b) Seismic drilling? No.
 - (c) Recompletion: Yes.
 - (d) Plugging and abandoning: Yes, Sundry Notice and Report on Wells.
2. Permit fee:
 - (a) Drilling: \$200.00.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: Plugging and Abandonment program by Sundry Notice , Division approval required
3. Require filing report of work performed: Oil and Gas Completion Report, Oil, Gas and Geothermal Well Plugging Report.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? Due to spacing requirements, directional surveys may be required during drilling operations. Upon well completion, bottom hole surveys are required.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Must be set into impervious formation. Not less than 500 ft. required on all wells or 10 percent of projected total depth if greater than 5,000 ft.
 - (b) Production casing: No provision.
2. Minimum amount of cement required:
 - (a) Surface casing: Circulate cement to surface.
 - (b) Production casing: 500 feet above bottom of casing.
 - (c) Setting time: Yes - minimum compressive strength of 300 psi at bottom-hole conditions must be attained.

3. Tubing requirements:

- (a) Oil wells: No.
- (b) Gas wells: No.

Completion

1. Completion report required: Yes - Oil and Gas Completion Report.

- (a) Time limit: Thirty days.
- (b) Where submitted: Division of Minerals.

2. Well logs required to be filed: Yes - two copies.

- (a) Time limit: Thirty days after completion.
- (b) Where submitted: Division of Minerals.
- (c) Confidential time period: Yes - six months. May be extended for series of wells.
- (d) Available for public use: Yes.
- (e) Log catalog available: No.

3. Multiple completion regulation: Yes.

- (a) Approval obtained: May be approved administratively.

4. Commingling in well bore: Yes.

- (a) Approval obtained: Production from one pool shall not be commingled with that from another pool in the same field before gauging.

Oil Production

1. Definition of an oil well: "Oil well" means any well which is not a gas well and which is capable of producing oil or condensate.

2. Potential tests required: No provision.

- (a) Time interval: No provision.
- (b) Witness required: No provision.

3. Statewide allowable: No.

- (a) Pool allowable: No.
- (b) Well allowable: Yes. May be limited by the Division after notice and hearing to protect correlative rights and to prevent waste.
- (c) Exempt allowable: No.

4. Maximum gas-oil ratio: No.

- (a) Provision for limiting gas-oil ratio: Yes. No well shall be permitted to produce gas in excess of the maximum ratio determined by the Division for a pool after notice and hearing.

- (b) Exception to limiting gas-oil ratio: Yes. If excess is returned to the pool from which produced.
- 5. Bottom-hole pressure test reports required: No provision.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: Yes. Common tankage may be used to receive the production from any number of wells, provided adequate tankage and other equipment is installed so that production for each well can be accurately determined at reasonable intervals.
- 7. Measurement involving meters: No provision.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes – Oil and Gas Producers Monthly Report.
 - (c) Time limit: Thirty days.

Gas Production

- 1. Definition of a gas well: "Gas well" means a well which produces primarily natural gas or any well classified as a gas well by the Division.
- 2. Pressure base 14.73 psia @ 60 degrees F.
- 3. Initial potential tests: Each gas well must be tested initially by the multipoint back pressure method at a time prescribed by the Division.
 - (a) Time interval: No provision.
 - (b) Witness required: No provision.
- 4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: Yes. May be limited by the Division after notice and hearing to protect correlative rights and to prevent waste.
 - (c) Exempt allowable: No.
- 5. Bottom-hole pressure test reports required: No provision.
 - (a) Periodical bottom-hole pressure surveys: No provision.
- 6. Commingling of gas in common facilities: Yes. Common tankage may be used to receive the production from any number of wells, provided adequate tankage and other equipment is installed so that production for each well can be accurately determined at reasonable intervals.
- 7. Measurement involving meters: Yes.
- 8. Production reports:

- (a) By lease: No.
- (c) By well: Yes.
- (d) Time limit: Thirty days.

Water Disposal

1. State agencies that control disposal of produced salt water: Division of Minerals, Division of Environmental Protection.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 62.5%.
 - (b) Royalty interest: 62.5%.

Taxation

Gas administrative fee = 100 mills per 50,000 per cubic ft of gas

Total gas tax burden = \$0.10 per 50,000 cubic feet of gas

Oil tax burden = 100 mills per barrel of oil

Total oil tax burden = \$0.10 per barrel of oil

1. Tax collecting agency: Administrative Fee - Nevada Division of Minerals, 400 W. King St., Suite 106, Carson City, NV 89703. Net Proceeds of Mines Tax - Nevada Department of Taxation, Capitol Complex, 1550 East College Parkway, Carson City, NV 89706.
2. How tax is computed: The administrative fee is 100 mills per BBL or 50,000 cubic feet of natural gas. The Net Proceed of Mines Tax is an annual assessment based on percent of net proceeds after allowable deductions.
 - (a) Notwithstanding the provisions of NAC 522.343, the amount of the administrative fee that a producer or purchaser of oil or natural gas must pay pursuant to subsection 2 of NRS 522.150 for new production is one-half cent per barrel of oil or per 50,000 cubic feet of natural gas, as appropriate, and in accordance with the provisions of this section.
 - (b) Upon the filing of Form 5, the well completion report, pursuant to NAC 522.510, the division shall determine whether the production from the well that is the subject of the report qualifies as new production. If the division determines that the production from the well qualifies as new production, the producer or purchaser is entitled to pay the administrative fee required by subsection 2 of NRS 522.150 for that new production at the reduced rate prescribed in subsection 1 for 12 consecutive months, beginning on the put-on production date reported in Form 5 for that well. At the end of the 12-month period, the producer or purchaser must pay the administrative fee required by NRS 522.150 for further production from the well in the amount prescribed in NAC 522.342.
 - (c) A producer or purchaser may, pursuant to NRS 522.110, challenge a determination made by the division pursuant to subsection 2.
 - (d) As used in this section, "new production" means production from a new or existing well that is completed in a new interval, as determined by the division.
3. Exemptions or exceptions: None.

4. Name of tax: Administrative Fee and Net Proceeds of Mines Tax.
5. Statutory citation: Administrative Fee: Nevada Revised Statutes (NRS) 522.150; Net Proceeds of Mines Tax – NRS 362.100.

Land Leasing Information

No regulations at this time.

Naturally Occurring Radioactive Material (NORM)

No NORM regulations at this time.

NEW YORK

Administration

1. State agency: Department of Environmental Conservation, Division of Mineral Resources, 625 Broadway, 3rd Fl., Albany, NY 12233-6500. Phone (518) 402-8056. Region 9 Office, 182 E. Union St., Allegany, NY 14706-1328. Phone (716) 372-0645. Region 8 Office, 6274 East Avon-Lima Road, Avon, NY 14414. Phone (585) 226-2466.
2. Docketing Procedure: Compulsory integration hearings will be held on a regular schedule to address recently permitted wells where the Department determines integration is necessary in accordance with new statutory provisions which took effect in August 2005. Other public hearings are held upon the Department's own motion or upon application of any interested party. The Department shall promptly fix a date for a hearing thereon. The hearings shall be held without undue delay after the filing of the petition. The Department shall make its order within sixty days after the close of the hearing record.
 - (a) Emergency orders: The Department may make an emergency order without notice or hearing, which shall be effective when made. No emergency order shall be effective for more than fifteen days.
 - (b) Notice – compulsory integration hearings: The well operator is responsible to provide notice to uncontrolled interests in spacing units and by publication at least 30 days prior to an integration hearing.
 - (c) Notice – other matters: At least ten days notice, exclusive of the date of service. The Department is responsible to give notice.

Bond

1. Compliance bond required: Yes, but only for post-regulatory (10/1/63) wells, and only with respect to plugging and abandonment.
2. Conditions of bond: That the well be properly plugged and abandoned, all notices and reports be filed with the Department and the surface be restored to a condition similar to the adjacent terrain.
 - (a) Amount per well:
 - (1) For wells less than 2,500 feet in depth:
 - a. 1 to 25 wells: \$2,500 per well, up to \$25,000.
 - b. 26 to 50 wells: \$25,000 plus \$2,500 per well in excess of 25, up to a total of \$40,000.
 - c. 51 to 100 wells: \$40,000 plus \$2,500 per well in excess of 50, up to a total of \$70,000.
 - d. Over 100 wells: \$70,000 plus \$2,500 per well in excess of 100, up to \$100,000.
 - (2) For wells between 2,500 feet and 6,000 feet in depth:
 - a. 1 to 25 wells: \$5,000 per well, up to \$40,000.
 - b. 26 to 50 wells: \$40,000 plus \$5,000 per well in excess of 25, up to a total of \$60,000.
 - c. 51 to 100 wells: \$60,000 plus \$5,000 per well in excess of 50, up to a total of \$100,000.
 - d. Over 100 wells: \$100,000 plus \$5,000 per well in excess of 100, up to a total of \$150,000.
 - (3) For wells over 6,000 feet in depth: Amount set by the Department based upon the anticipated cost to plug the well. Not to exceed \$250,000 per well, up to a total of \$2,000,000.
 - (4) If the operator has wells described in (1) and others in (2), instead of providing bonding to satisfy the provisions of each category, he/she may provide an amount as if all the wells were between 2,500 feet and 6,000 feet in depth.
 - (b) Amount of blanket bond: No bond required in excess of (a).
3. Acceptable alternatives to a surety bond:

- (a) Cash on deposit with Department.
- (b) Escrow account.
- (c) Irrevocable letter of credit.
- (d) Certificate of Deposit.

Spacing

1. Spacing requirements: Yes.

- (a) Density, gas wells outside of pre-1995 fields which are not being extended:
 - (1) Medina or shale, any depth: 40 acres +/- 10%.
 - (2) Onondaga reef or Oriskany, any depth: 160 acres +/- 10%.
 - (3) Fault-bounded Trenton and/or Black River hydrothermal dolomite, 4000 - 8000 feet deep: 320 acres +/- 10%.
 - (4) Fault-bounded Trenton and/or Black River hydrothermal dolomite, deeper than 8000 feet: 640 acres +/- 5%.
 - (5) All other pools, less than 4000 feet deep: 80 acres +/- 10%.
 - (6) All other pools, 4000 - 6000 feet deep: 160 acres +/- 10%.
 - (7) All other pools, 6000 - 8000 feet deep: 320 acres +/- 10%.
 - (8) All other pools, deeper than 8000 feet: 640 acres +/- 5%.
- (b) Density, all other non-exempt fields, pools or wells: 40 acres or in the center of a circle of radius 660 feet, subject to change under provision of a spacing order.
- (c) Lineal, gas wells outside of pre-1995 fields which are not being extended:
 - (1) Medina or shale, any depth: 660 feet from any unit boundary.
 - (2) Onondaga reef or Oriskany, any depth: 660 feet from any unit boundary.
 - (3) Fault-bounded Trenton and/or Black River hydrothermal dolomite, 4000 - 8000 feet deep: one-half mile from any other well in another unit in the same pool and no less than 1000 feet from any unit boundary that is not defined by a field-bounding fault and in no even less than 660 feet from any unit boundary.
 - (4) Fault-bounded Trenton and/or Black River hydrothermal dolomite, deeper than 8000 feet: one mile from any other well in another unit in the same pool and no less than 1500 feet from any unit boundary that is not defined by a field-bounding fault and in no even less than 660 feet from any unit boundary.
 - (5) All other pools, less than 4000 feet deep: 660 feet from any unit boundary.
 - (6) All other pools, 4000 - 6000 feet deep: 660 feet from any unit boundary.
 - (7) All other pools, 6000 - 8000 feet deep: 1000 feet from any unit boundary.
 - (8) All other pools, deeper than 8000 feet: 1500 feet from any unit boundary.

- (d) Lineal, all other non-exempt fields, pools, or wells: 660 feet from the boundary line of any lease or unit and 1,320 feet from any other producing well completed or being drilled to the same pool.
 - (e) Wells along the NY/PA state border have a reduced minimum setback distance of 330 feet.
 - (f) A spacing order promulgated after notice and a comment period supersedes statewide spacing provisions.
2. Exceptions: Yes.
- (a) Basis: Reasonable exceptions to protect correlative rights and prevent waste.
 - (b) Approval, gas wells outside of pre-1995 fields which are not being extended: A spacing order is required before the well permit may be issued. The Order may be issued after notice and a comment period, without a hearing, if no substantive and significant issues are raised. A hearing will be scheduled if the Department determines that a substantive and significant issue has been raised in a timely manner.
 - (c) Approval, all other non-exempt fields, pools or wells: May be granted administratively after proper notice and if no objections are filed. A public hearing is required if a substantive and significant dispute exists.
 - (c) Oil fields or pools discovered, developed and operated prior to 1/1/81 are exempt from spacing requirements.
 - (d) Underground gas storage wells, solution salt mining wells, brine disposal wells, stratigraphic wells and geothermal wells are exempt from spacing requirements.

Pooling

- 1. Authority to establish voluntary: Yes.
- 2. Authority to establish compulsory: Yes.

Drilling Permit

- 1. Require permits for:
 - (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes.
 - (d) Plugging and abandoning: Yes.
 - (e) Stratigraphic test well: Yes, if greater than 500 feet deep.
 - (f) Geothermal well: Yes, if greater than 500 feet deep.
 - (g) Brine disposal well: Yes, if greater than 500 feet deep.
- 2. Permit fee:
 - (a) \$100 plus \$190 for each 500 feet of depth or portion thereof.
 - (b) Seismic drilling: None. No permit required.

- (c) Recompletion: If recompletion includes deepening the well to a lower zone, a permit fee is required; in other cases no fee is required.
- (d) Plugging and abandoning: None.
- 3. Require filing report of work performed: Yes.

Vertical Deviation

- 1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? Upon Department request and/or as a condition of permit to drill an intentionally deviated well.
 - (b) Filing of survey required? Yes.

Casing and Tubing

- 1. Minimum amount required:
 - (a) Surface casing: Minimum of 75 feet below deepest fresh water formation or 75 feet into bedrock, whichever is greater.
 - (b) Production casing: Prevent migration between zones and commingling.
- 2. Minimum amount of cement required:
 - (a) Surface casing: Cement to surface.
 - (b) Production casing: To a height sufficient to prevent any movement of oil, gas or water outside of the casing. In principal or primary aquifer areas, production casing must be cemented to the surface.
 - (c) Setting time: Yes. Prudent current industry practices, according to casing and cementing guidelines issued by our office.
- 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

- 1. Completion report required: Yes.
 - (a) Time limit: Within 30 days after completion of any well.
 - (b) Where submitted: NYS Department of Environmental Conservation, Division of Mineral Resources for region where well is located.
- 2. Well logs required to be filed: Yes.
 - (a) Time limit: Within 30 days after completion of any well.

- (b) Where submitted: NYS Department of Environmental Conservation, Division of Mineral Resources for region where well is located.
 - (c) Confidential time period: Department will hold well logs and completion data confidential for six months from spud date. This period may be extended an additional six months if drilling has been continuous throughout the first six month period. An operator may request a maximum of two years confidentiality pursuant to Section 23-0313 of the New York State Oil, Gas and Solution Mining Law.
 - (d) Available for public use: Yes. Access is available after the applicable six month or two-year confidentiality period expires.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes. 6NYCRR 554.6.
 - (a) Approval obtained: Prior permission is required for a multiple completion.
 4. Commingling in well bore: Yes, with permission of the Department.
 - (a) Approval obtained: By application. Approval may be granted on an administrative basis or after public hearing at the Department's discretion.

Oil Production

1. Definition of an oil well: No definition.
2. Potential tests required: If pertinent (not on stripper wells).
 - (a) Time interval: At operator's discretion.
 - (b) Witness required: No.
3. Statewide allowable:
 - (a) Pool allowable: No in most areas.
 - (b) Well allowable: No, except under regulations for the "Bass Island" trend or as provided in a spacing order.
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: 2,000 cu. ft./bbl. but can be changed by application and public hearing.
 - (a) Provision for limiting gas-oil ratio: Yes.
 - (b) Exception to limiting gas-oil ratio: Only on a pool basis. By application and public hearing.
5. Bottom-hole pressure test reports required: Only in specific instances.
 - (a) Periodical bottom-hole pressure surveys: Only in specific instances.
6. Commingling oil in common facilities: Yes, upon application to and with prior approval of the Department.
7. Measurement involving meters: No.
8. Production reports:
 - (a) By lease: Yes, annually.

- (b) By well: Yes, annually.
- (c) Time limit: Three months after close of calendar year to which report pertains. "Bass Island" well production is reported on a quarterly basis, filed within 60 days after the close of the quarter concerned.

Gas Production

1. Definition of a gas well: No definition.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: At operator's discretion.
 - (b) Witness required: No.
4. Statewide allowable:
 - (a) Pool allowable: No.
 - (b) Well allowable: No, except under regulations for the "Bass Island" or as provided in a spacing order.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Only in specific instances.
 - (a) Periodical bottom-hole pressure surveys: Only in specific instances, "Bass Island" wells are tested annually.
6. Commingling of gas in common facilities: Yes, upon application to and with prior approval of the Department.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes [if available – delete text in brackets].
 - (c) Time limit: Three months after close of calendar year to which report pertains. "Bass Island" well production is reported on a quarterly basis, filed within 60 days after the close of the quarter concerned.

Water Disposal

1. State Agencies that control disposal of produced salt water: Department of Environmental Conservation, Division of Water, Division of Environmental Permits, and Division of Mineral Resources.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 60%.
 - (b) Royalty interest: 60%.

Taxation

There is no state severance tax levied on oil and gas in New York. However, oil and gas properties are taxed at the local level and production is a factor in determining the assessed value of the property. The NYS Office of Real Property Tax Services sets the unit of production based on data supplied by operators. For performing that service the state charges operators an annual fee based on production.

Land Leasing Information

1. Leasing Method: Sealed bids. Negotiated lease option for small tracts.
2. Notice Method: Published in the official newspaper or newspapers or otherwise in a newspaper designated for such purposes.
3. Bid Guarantee \$ (per acre): \$500.00 for each nominated area + \$1 per acre, if the tract is 125 acres or less, then min. \$5 per acre. Minimum bid is \$15.00 per acre.
4. Qualification of the bidder: Any person in compliance with the Law and Regulations.
5. State Statutes: New York State Environmental Conservation Law § 23-1101
6. Maximum acres: No established maximum.
7. Contact: Charles Gilchrist
Phone: (518) 402-8056
E-mail: crgilchr@gw.dec.state.ny.us
8. Leasing Method: Sealed bids. Negotiated noncompetitive lease option for split minerals interests and small tracts necessary to consolidate production units.
9. Notice Method: Published in the official newspaper or newspapers or otherwise in a newspaper designated for such purposes.
10. Bid Guarantee \$ (per acre): \$500.00 for each nominated area + \$1 per acre, if the tract is 125 acres or less, then min. \$5 per acre. Minimum bid is \$15.00 per acre.
11. Qualification of the bidder: Any person.
12. State Statutes: New York State Environmental Conservation Law § 23-1101
13. Maximum acres: No established maximum.
14. Contact: Charles Gilchrist
Phone: (518) 402-8056
E-mail: crgilchr@gw.dec.state.ny.us

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environmental Conservation (DEC), Division of Solid & Hazardous Materials, 625 Broadway, 9th Floor, Albany, NY 12233-7255. Phone: (518) 402-8579, Fax: (518) 402-8646
2. Relevant Statute/Regulations: 6 NYCRR Part 380 - Rules and Regulations for Prevention and Control of Environmental Pollution by Radioactive Materials.

3. Scope: Discharge and disposal of radioactive materials; applies to NORM if:
 - (a) Processed and concentrated and
 - (b) Subject to radioactive materials licensing.
4. Licensing: Department of Environmental Conservation is not a radioactive materials licensing agency. The licensing agencies in New York State (State Health Department, State Labor Department, New York City Health Department) have not required licenses for NORM from oil and gas production.
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land: DEC has cleanup guidelines for soils contaminated with radioactive materials (DSHM, TAGM 4003); DEC does not regulate sale of NORM-contaminated land.
10. Projected Volume of stored NORM in the State: DEC has not made this estimate.
11. Contact: Barbara Youngberg.

NEW MEXICO

Administration

1. State agency: New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, 1220 S. Saint Francis Drive, Santa Fe, NM 87505. Phone (505) 476-3440, FAX (505) 476-3462, Web site <http://emnrd.state.nm.us/ocd>.
2. Docketing procedure: Upon receipt of a proper application, the Division will hold a public hearing at such time and place as it prescribes, not less than 30 days after filing of the application. The Division Director may appoint members of the staff as Examiners to conduct public hearings.
 - (a) Emergency orders and rules: Action by the Division without a hearing. Orders issued without hearing remain in force no longer than 15 days. Emergency hearings may be called with shortened notice. Rule 1225.
 - (b) Notice: Dependent on type of proceeding. Minimum of 20 days, except in emergency. By applicant. Rule 1210.

Financial Assurance

1. Plugging financial assurance required: Yes. NMSA 1978, § 70-2-14. Rule 101. Surety, cash bond, irrevocable letter of credit, or well-specific plugging insurance policy.
2. Conditions of financial assurance: That the well be plugged and abandoned, and the well site remediated, in compliance with Division rules.
 - (a) Amount per well: \$5,000 plus \$1.00 per foot of depth in major producing counties; \$10,000 plus \$1.00 per foot of depth elsewhere.
 - (b) Amount of blanket bond: \$50,000.
Single well bond may be required in addition to blanket bond for wells inactive for more than 2 years. NMSA 1978 § 70-2-14; Rule 101.
3. Waste management facilities: Rule 53.
 - (a) Commercial facilities: Greater of (i) \$25,000 or (ii) closure cost estimate (Note: Existing facilities capped at \$250,000 per facility, except in event of a major modification).
 - (b) Centralized facilities: \$25,000 per facility or \$50,000 statewide blanket bond.

Spacing

1. Spacing requirements: Yes. Rule 104 or special pool rules, unless otherwise specified by special pool rules.
 - (a) Density: 40 acres for an oil well. SE gas: 160 acres to Top Wolfcamp and 320 acres (with 2 wells allowed per 320-acre unit) Wolfcamp and older. NW gas: 160 acres to base of the Dakota and 640 acres below the Dakota. All other areas 160-acre gas.
 - (b) Lineal: Oil: 330 feet from spacing unit boundary. Gas: 660 feet from spacing unit boundary 10 feet from any quarter/quarter line in a 160 acre or 320 acre unit; 1200 feet from unit boundary, 130 feet from any quarter line and 10 feet from any quarter/quarter line in a 640-acre unit.
2. Exceptions to well location requirements: Yes.
 - (a) Basis: When necessary to prevent waste or protect correlative rights. Rule 104F. Water floods and pressure maintenance. Rule 701.

- (b) Approval: District Offices for waterfloods and pressure maintenance; Administrative for other reasons. Any application may be set for hearing.
- 3. Exceptions to acreage/density requirements: Yes.
 - (a) Basis: Exceptions to acreage requirements may be granted to conform to U.S. Public land surveys or if proposed unit meets certain configuration requirements. Exception to number of wells in a unit may be granted at discretion of the Director. Rule 104.D.
 - (b) Approval: Exceptions to acreage requirements necessary to conform to public land surveys may be approved by District Office for small variances, or administratively for longer variances. Other exceptions may be approved administratively. Exceptions to numbers of wells per unit require hearing. Any application may be set for hearing. Rule 104.D.

Pooling

- 1. Authority to establish voluntary: Yes.
- 2. Authority to establish compulsory: Yes for separate tracts or undivided interests within a spacing unit. NMSA 1978, § 70-2-17 and 70-2-18. Rule 35.

Drilling Permit

- 1. Require permits for: All lands.
 - (a) Drilling a producing or service well: Rules 102 and 1101. Permitting on federal lands coordinated with BLM. Rule 1128.
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes. Rule 1102. Permitting on federal lands coordinated with BLM. Rule 1128.
 - (d) Plugging and abandoning: Yes. Rule 1103.
- 2. Permit fee:
 - (a) Drilling: None.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
- 3. Require filing report of work performed: Yes. Rule 1103.

Vertical Deviation

- 1. Regulation requirement: Yes. Rule 111.
 - (a) When a wellbore deviates more than five degrees in any 500-foot interval and where there exists the possibility that such excessive deviated wellbore exceeds the distance to the nearest outer boundary line of that well's spacing unit.
 - (b) Filing of survey required: Yes.

Casing and Tubing

1. Minimum amount required: Rule 107.
 - (a) Surface casing: Through all usable fresh water zones.
 - (b) Production casing: To sufficient depth to ensure protection of all oil and gas bearing strata, including the one(s) being produced.
 - (c) Specific requirements in certain areas.
2. Minimum amount of cement required: Rule 107 B-I.
 - (a) Surface casing: Yes, circulate to surface.
 - (b) Production casing: Yes, to ensure protection of all oil and gas bearing strata encountered in the well, including the oar(s) being produced.
 - (c) Setting time: 18 hours in some areas; in other areas where cement has reached a compressive strength of 500 psi – see rule 107.G.
3. Tubing requirements:
 - (a) Flowing oil wells: Yes, if casing larger than 2 7/8 inches.
 - (b) Gas wells: Yes, if casing larger than 3 1/2 inches.

All flowing oil wells and gas wells: Set tubing as near the bottom as practical with tubing perforations not more than 250 feet above top of pay.

Completion

1. Completion report required: Yes. Rules 117 and 1105.
 - (a) Time limit: Within 20 days following completion.
 - (b) Where submitted: Appropriate district office.
2. Well logs required to be filed: Yes. Rule 1105.
 - (a) Time limit: 20 days.
 - (b) Where submitted: District office.
 - (c) Confidential time period: Yes. 90 days if requested in writing.
 - (d) Available for public use: Yes.
 - (e) Log catalog information: No, but all logs are currently available on the Division's Internet Web site. (Commercial microfilm available; IHS Energy Group and MJ Systems in Denver. Also, New Mexico Bureau of Mines, New Mexico Institute of Mining and Technology, Socorro, New Mexico have duplicate copies of most logs filed with the Division).
3. Multiple completion regulation: Rule 112-A.

- (a) Approval obtained: By District approval of Form C-101 and/or C-103.
4. Commingling in well bore: Rule 303-C.
- (a) Approval obtained: Administrative in most cases; appropriate cases set for hearing. Ability to establish reference cases to simplify processes. Rule 303-C.

Oil Production

1. Definition of an oil well: Any well that produces less than 100,000 cu. ft. of gas per barrel of oil from a pool classified as an oil pool. Rules 7.G(5) and 7.0(4). In an associated oil and gas pool it is a well that produces less than 30,000 cu. ft. per barrel. Rules of the "General Rules and Regulation for the Associated Oil and Gas Pacts of NW and SE New Mexico" as promulgated by R-5353, as amended.
2. Potential tests required: No.
 - (a) Time interval: None specified. Not applicable.
 - (b) Witness required: No. Not applicable.
3. Statewide allowable: Yes. Rule 505.
 - (a) Pool allowable: Pool rules may establish well allowables at levels different than statewide allowables.
 - (b) Well allowable: Yes. From periodic gas-oil ratio tests.
 - (c) Exempt allowable: Yes. Discovery allowables.
4. Maximum gas-oil ratio: 2,000:1.
 - (a) Provision for limiting gas-oil ratio. Yes. Top pool allowable times limiting GOR for that pool.
 - (b) Exception to limiting gas-oil ratio. Yes. After notice and hearing, pool GOR could be increased.
5. Bottom-hole pressure test reports required: In some pools.
 - (a) Periodic bottom-hole pressure surveys: In some pools.
6. Commingling oil in common facilities: Yes. Rules 303.B. Administrative approval provided that production is accurately measured prior to commingling. Application may be set for hearing if there is diverse ownership and an owner objects, or otherwise at the direction of the Director.
7. Measurement involving meters: In Automatic Custody Transfer and where there is diversified ownership in commingling.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Rule 1115.
 - (c) Time limit: 15th day of second month following the month of production.

Gas Production

1. Definition of a gas well: Any well that produces from a pool classified as a "gas pool" or produces with a GOR of 100,000 cu. ft. per barrel or more. In associated pool, it is a well which produces with a GOR of 30,000 cu. ft. per barrel or more.
2. Pressure base 15.025 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: 30 days after Christmas tree - unconnected wells. 60 days after connection to gas transportation system.
 - (b) Witness required: No.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes. Set twice yearly for prorated pools. Rule 605, Order No. R-8170-H, as amended.
 - (b) Well allowable: Yes. Proration schedules for prorated pools published in April and October allocating pool allowable to individual wells; schedules currently suspended.
 - (c) Exempt allowable: Hardship wells may be authorized (after notice and hearing) to produce at a minimum rate. Minimum allowables for prorated pools may also be established on a pool basis after notice and hearing.
5. Bottom-hole pressure test reports required: No.
 - (a) Periodic bottom-hole pressure surveys: No.
 - (b) Surface Pressures: No.
6. Commingling of gas in common facilities: Yes.
7. Measurement involving meters: All gas must be accounted for by metering or other method approved by the Division. Rule 403.A.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Rule 1115.
 - (c) Time limit: 15th day of second month following the month of production. Note: Gas transporter must file a report of gas taken by the 15th day of the second month following the month the gas was taken.

Water Disposal

1. State agencies that control disposal of produced salt water and all related oil field waste: New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division. Rules 50, 701-712.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: For secondary recovery and pressure maintenance only. NMSA 1978, §70-7-1 through 70-7-21.
2. Minimum percentage for ratification of the order providing for unit operations:
 - (a) Working interest: 75%.

- (b) Royalty interest: 75%.

Taxation

Gas severance tax = 3.75%
 Gas ad valorem production tax = varies due to county derived rate
 Gas school tax = 4.0%
 Gas conservation tax = .19%
 Gas ad valorem equipment tax = county derived rate
 Total gas tax burden = approximately 9.14%

Oil severance tax = 3.75%
 Oil ad valorem tax = varies due to county derived rate
 Oil school tax = 3.15%
 Oil conservation tax = .19%
 Oil ad valorem equipment tax = county derived rate
 Total oil tax burden = approximately 8.29%

1. Tax collection agency: Taxation and Revenue Department, Audit and Compliance Division, Oil and Gas Bureau, P.O. Box 2308, Santa Fe, NM 87504-2308.
2. How tax is computed:
 - (a) school tax: 4% (gas) 3.15% (oil)
 - (b) severance tax: 3.75% (oil, gas)
 - (c) conservation tax: .19% (oil, gas)
 - (d) ad valorem production tax: variable due to county derived rate
 - (e) natural gas processors tax: effective 1/1/99, tax is imposed on the amount of MMBTUs of natural gas delivered to a processor at a processing facility. Tax rate is derived on a state fiscal year basis and is calculated through a statutory-based method.
 - (f) ad valorem equipment tax: derived by county and is based from values reported by taxpayers from previous calendar year and is assessed against the operator of record of the property.
3. Due dates:
 - (a) school, severance, conservation, ad valorem production: 55 days after month of sale.
 - (b) natural gas processors tax: 25 days after the month of receipt of gas by processor.
 - (c) ad valorem equipment tax: assessed to operator in October (based on previous year's taxable value) and due November 30.
4. Adjustments:
 - (a) Adjustments recognized for school, severance, conservation, and ad valorem production tax include:
 - (1) royalties paid or due to the United States, the State of New Mexico or any Indian tribe, Indian pueblo or Indian ward of the United States.
 - (2) actual costs associated with transportation and processing.
 - (b) Adjustments recognized for the natural gas processors tax include MMBTU's of natural gas that are:

- (1) used for natural gas processing by the processor.
- (2) returned to the lease from which it is produced.
- (3) legally flared by the processor.
- (4) lost as a result of processing plant malfunction or other incidences of force majeure.

5. Tax incentives:

- (a) well-workover projects - 2.45% severance tax on the excess of the production projection for both oil and natural gas.
- (b) production restoration projects - zero severance tax rate for ten years on natural gas and oil.
- (c) Indian intergovernmental tax credit - 75% of the lesser of:
 - (1) the aggregate amount of severance-type taxes imposed by the Indian nation or
 - (2) the aggregate amount of severance-type taxes imposed by the State.
- (d) qualified enhanced oil recovery projects - 1.875% severance tax rate on oil
- (e) Stripper well properties - incentive rates apply both to severance tax and school tax.

REPEALED EFFECTIVE 12-31-05.

Note: All incentive programs may be sunsetted based upon prices currently recognized for oil.

6. Statutory citation:

- (a) Severance tax: NMSA Section 7-29-1 et seq.
- (b) Conservation tax: NMSA Section 7-30-1 et seq.
- (c) Emergency school tax: NMSA Section 7-31-1 et seq.
- (d) Natural gas processors tax: NMSA Section 7-33-1 et seq.
- (e) Ad valorem production tax: NMSA Section 7-32-1 et seq.
- (f) Production equipment ad valorem tax: NMSA Section 7-34-1 et seq.

Land Leasing Information

- 1. Leasing Method: A monthly two part competitive sale, with the first part of the sale being sealed bids that have been received by the Accounting Division of the State Land Office prior to 9:30 am of sale day. Part two is additional tracts by oral auction as listed in the sale notice.
- 2. Notice Method: A lease sale notice bulletin is mailed approximately three weeks prior to each monthly sale to all industry operators that have been placed at their request on the mailing list. An un-official copy of the sale notice is available through baervan@nmt.edu.
- 3. Minimum bidding: Called a "minimum bonus bid" and set at \$10,000.00 for a standard 640-acre section (a 320 acre tract would be \$5,000.00), in the restricted (producing) areas. Minimum bonus in the non-restricted (frontier) areas is set at \$1.00 per acre.
- 4. Qualification of the bidder: No pre-qualifying of bidders except for the assignment of a computer identification number called an OGRID Number.

5. State Statutes: NMSA 1978, § 19-7-1, NMSA 1978, § 19-10-17, NMSA 1978, § 19-10-70.
6. Minimum acres: Tracts offered in both restricted and non-restricted areas are limited to a maximum of one full section (approximately 640 acres).
7. Contact person: Joe Mraz
Phone: (505) 827-5774
E-mail: jmraz@slo.state.nm.us
Naturally Occurring Radioactive Material (NORM)
1. Regulating Agency: Radiation Licensing and Registration Section, New Mexico Environmental Department (NMED).
Oil Conservation Division, New Mexico Energy, Minerals and Natural Resources Department (OCD).
2. Relevant Statute/Regulation:

NMED: Naturally Occurring Radioactive Materials in the Oil and Gas Industry (Subpart 14)

Scope: Apply to persons who engage in extraction, transfer, storage or disposal of NORM. Apply to sludges and scale and storage and cleaning of tubulars and equipment.

OCD: Disposal of Regulated Naturally Occurring Radioactive Material (Rule 714)

Scope: Establish procedures for the disposal of regulated NORM.
3. Licensing: General and specific
4. Cleaning Equipment: Allowed under worker protection plans and limits of exposures in the regulations.
5. Disposal of Waste: Not regulated if 30 Pico curies per gram or less of Ra226 above background or 150 Pico curies per gram or less of any other NORM radio nucleide about background. Disposal in commercial-centralized facilities, plugged and abandoned wells, Class I and II injection wells permitted with permit. Disposal of regulated NORM in non-retrievable flow lines and pipelines permitted so long as the accumulation resulted from normal operations.
6. Subsequent Use of Equipment: Facilities and equipment containing regulated NORM shall not be released for unrestricted use.
7. Storage of Materials: NORM can be stored up to one year under general licenses, longer under specific licenses or an extension granted by NMED.
8. Projected Volume of Stored NORM in the State: Unknown
9. Respondent: Jerrie Moore, NMED; Roger Anderson, OCD

NORTH CAROLINA

Administration

1. State agency: Department of Environment and Natural Resources, Division of Land Resources, 1612 Mail Service Center, Raleigh, NC 27699-1612. Phone (919) 733-3833.
2. Docketing procedure: The structure and operating procedure of our regulatory agency is by design both simple and flexible. However, should oil and gas production become a reality, the agency would be restructured as is deemed necessary.
 - (a) Emergency orders:
 - (b) Notice:

Bond

1. Compliance bond required: Yes, Rule .0004.
2. Conditions of bond: The bond is conditioned that "any well opened or caused to be opened by an operator shall, upon abandonment, be plugged in accordance with the rules and regulations of said department."
 - (a) Amount per well: \$5,000.
 - (b) Amount of blanket bond: None.

Spacing

1. Spacing requirements: No, "upon completion of a discovery well within a new pool or reservoir, the Department shall consider and adopt, after public hearing, temporary well spacing and drilling units." As additional reservoir information becomes available, permanent rules and regulations will be adopted including: minimum drilling unit; method of determining pool allowable; method of allocating total allowable; minimum distances from separate leasehold or pooled unit and between wells to the same reservoir.
2. Exceptions: Yes, Rule .0006 (c).
 - (a) Basis: The basis for such exceptions is topographic conditions, geologic conditions and other pertinent conditions.
 - (b) Approval: Exceptions are granted if it is shown that more hydrocarbons can be recovered under the leasehold by such exceptions.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes.
 - (b) Seismic drilling? No.

- (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes.
2. Permit fee:
 - (a) Drilling: \$50.
 - (b) Seismic drilling:
 - (c) Recompletion: \$15.
 - (d) Plugging and abandoning? \$15.
 3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? A directional survey is necessary for each well subsequently produced for oil or gas. "All wells shall be drilled in such a manner that vertical deviation of the hole does not exceed 3 degrees between the bottom of the hole and the top of the hole, and shall not deviate in such a manner as to cross property or unit lines."
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required: Yes, Rule .0007.
 - (a) Surface casing: Yes, "The surface casing shall extend from the surface to the first impervious layer not less than 50' below all fresh water strata."
 - (b) Production casing: No.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes, "the casing shall be so centralized and the annulus of such size that cement can be injected to fill the entire space behind casing back to the surface."
 - (b) Production casing: Yes, "it shall be cemented with sufficient volume to fill the annular space back of the casing to a point at least 500' above casing shoe and at least 50' above the producible reservoir nearest to the surface."
 - (c) Setting time: Yes, "if drilling is to continue following cementing operations, the cement shall set a minimum of 24 hours before the plug is drilled."
3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes, Rule .0008.

- (a) Time limit: A completion report must be filed within 30 days after completion of a producing well.
 - (b) Where submitted: The report must be submitted to the Department on a form prescribed by the Department.
2. Well logs required to be filed: Yes.
- (a) Time limit: The filing of well logs is required within 30 days of termination of drilling operations.
 - (b) Where submitted: The well logs are held in permanent files within the Department at the office of the State Geological Survey.
 - (c) Confidential time period: Yes, "upon request of the operator, the Department will hold such information in confidence for a period of 1 year. Extensions of this confidentiality shall be allowed up to a maximum of 1 year at the discretion of the Department."
 - (d) Available for public use: Yes.
 - (e) Log catalog available: A compilation of all data available on the exploratory oil wells drilled through 1976 (Information Circular #22) can be purchased from the State Geological Survey for \$3.00.
3. Multiple completion regulation: No, there are no such regulations at the present time; however, the Department does have the authority to adopt such regulations.
- (a) Approval obtained:
4. Commingling in well bore: No, there are no such regulations at the present time; however, the Department does have the authority to adopt such regulations.
- (a) Approval obtained:

Oil Production

NOTE: Because there has been no oil or gas production within the state, the rules and regulations concerned with production are of a general nature. However, should production become a reality, these general areas will be addressed and specific regulation will be adopted where necessary.

- 1. Definition of an oil well: An oil well is any well capable of producing crude petroleum oil and all other hydrocarbons regardless of gravity, which are produced at the well in liquid form.
- 2. Potential tests required: No.
 - (a) Time interval:
 - (b) Witness required:
- 3. Statewide allowable: The Department has the authority to limit production, upon public hearing, but the specifics have not been addressed in the present set of regulations.
- 4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio:
 - (b) Exception to limiting gas-oil ratio:
- 5. Bottom-hole pressure test reports required: Yes.

- (a) Periodical bottom-hole pressure surveys: Yes.
- 6. Commingling oil in common facilities: No.
- 7. Measurement involving meters: No.
- 8. Production reports: No.
 - (a) By lease:
 - (b) By well:
 - (c) Time limit:

Gas Production

- 1. Definition of a gas well: A gas well is any well capable of producing natural gas including casinghead gas and all other fluid hydrocarbons not defined as oil.
- 2. Pressure base None psia @ ____ degrees F.
- 3. Initial potential tests: No.
 - (a) Time interval:
 - (b) Witness required:
- 4. Statewide allowable: The Department has the authority to limit production, upon public hearing, but the specifics have not been addressed in the present set of regulations.
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: Yes.
- 6. Commingling of gas in common facilities: No.
- 7. Measurement involving meters: No.
- 8. Production reports: No.
 - (a) By lease:
 - (b) By well:
 - (c) Time limit:

Water Disposal

- 1. State agencies that control disposal of produced salt water: The Division of Water Quality within the Department is responsible for the control of water disposal.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source of supply: No.
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization:

- (a) Working interest:
- (b) Royalty interest:

Taxation

There is no state tax levied on oil and gas production in North Carolina.

Land Leasing Information

No Regulations at this time.

Naturally Occurring Radioactive Materials (NORM)

1. Regulating Agency: Division of Radiation Protection, 3825 Barrett Dr., Raleigh, NC 27609-7221. Phone: (919) 571-4141, Fax: (919) 571-4148.
2. Relevant Statute/Regulations: G.S. 104E and 15A NCAC Chapter 11.
3. Scope: All aspects of radiation protection.
4. Licensing: Uses and sources of radioactive material and particle accelerators.
5. Cleaning Equipment: U.S. Department of Transportation contamination limits.
6. Disposal of Waste: LLRW.
7. Subsequent Use of Equipment: Per case basis.
8. Subsequent Use of Materials: Per case basis.
9. Release/Sale of NORM-Contaminated Land: Per case basis.
10. Projected Volume of stored NORM in the State: Unknown; large PO4 plant.
11. Respondent: Richard Fry.

NORTH DAKOTA

Administration

1. State agency: North Dakota Industrial Commission, Dept. of Mineral Resources, Oil and Gas Division, 600 East Boulevard Ave., Dept. 405, Bismarck, ND 58505-0840. Phone (701) 328-8020. Web site: www.oilgas.nd.gov
2. Docketing procedure: North Dakota Century Code (NDCC) Section 38-08-11. Upon application or motion of the Commission, a hearing before the Commission is set at which time as will permit 15 days notice.
 - (a) Emergency orders: Emergency orders may be issued by the Commission, and shall remain in force until a proper order can be issued, after notice and hearing, but not more than 40 days.
 - (b) Notice: Fifteen days notice is required for all hearings except hearings involving a complaint which requires 45 days notice. The Commission is responsible for giving notice either by personal service or by one publication in a newspaper of general circulation in the State Capitol and in a newspaper of general circulation in the county where the affected property is situated.

Bond

1. Compliance bond required: North Dakota Administrative Code (NDAC) Section 43-02-03-15. Surety or Cash Bond.
2. Conditions of bond: Full compliance with the statutes, rules and regulations of the Commission.
 - (a) Amount per well: \$20,000, except that wells drilled to a total depth of 2,000 feet or less may be bonded in a lesser amount upon administrative approval.
 - (b) Amount of blanket bond: Ten wells or less, \$50,000. The \$50,000 blanket bond is limited in its coverage to contain no more than three unplugged dry holes, plugged wells with site not reclaimed, and/or abandoned wells. More than 10 wells, \$100,000. The \$100,000 blanket bond is limited in its coverage to contain no more than six unplugged dry holes, plugged wells with site not reclaimed, and/or abandoned wells.
 - (c) Commercial disposal wells are not allowed on blanket bonds. Each such well is bonded at the \$20,000 single well rate.
 - (d) Secondary recovery projects require a unit bond in the appropriate amount as listed in paragraphs (a) and (b) above.

Spacing

1. Spacing requirements: NDAC Section 43-02-03-18. Within 30 days after oil or gas is discovered in a pool not covered by an order of the Commission, a spacing hearing is docketed. In the absence of an order of the Commission, the general spacing regulations are as follows:
 - (a) Density (vertical or directional oil well): 40 acres for vertical or directional oil wells drilled and projected no deeper than the Mission Canyon Formation; 160 acres for vertical or directional oil wells drilled or projected deeper than the Mission Canyon Formation; 160 acres for gas wells.
 - (b) Lineal (vertical or directional oil well): Not less than 500 feet from the 40-acre drilling unit boundary for vertical or directional oil wells no deeper than the Mission Canyon Formation and not less than 660 feet from the 160-acre drilling unit boundary for vertical or directional oil wells deeper than the Mission Canyon Formation. Not less than 500 feet to any 160-acre drilling unit boundary for gas wells projected no deeper than the Mission Canyon Formation and not less 660 feet to any 160-acre drilling unit boundary for gas wells projected deeper than the Mission Canyon Formation.

- (c) Density (horizontal oil wells): 320 and 640 acres for horizontal oil wells.
 - (d) Lineal (horizontal oil wells): Not less than 500 feet from the 320 or 640-acre drilling unit boundary for horizontal oil wells.
 - (e) Density (gas wells): 160 acres for gas wells.
 - (f) Lineal (gas wells): Not less than 500 feet from the 160-acre drilling unit boundary for gas wells drilled or projected no deeper than the Mission Canyon Formation; not less than 660 feet from the 160-acre drilling unit boundary for gas wells drilled or projected deeper than the Mission Canyon Formation.
2. Exceptions: Yes—NDAC Section 43-02-03-18.1.
- (a) Basis: Surface conditions require or well at proper location would not produce in paying quantities, also, in order to protect correlative rights, prevent waste, or effect greater ultimate recovery of oil and gas.
 - (b) Approval: By order of the Commission after notice and hearing.

Pooling

- 1. Authority to establish voluntary: Yes—NDCC Section 38-08-08 and NDAC Section 43-02-03-16.3.
- 2. Authority to establish compulsory: Yes—Section 38-08-08 and NDAC Section 43-02-03-16.3.

Drilling Permit

- 1. Require permits for:
 - (a) Drilling a producing or service well? Yes—NDAC Section 43-02-03-16.
 - (b) Seismic drilling? Exploration permit required—NDAC Section 43-02-12-04.
 - (c) Recompletion? Yes—NDAC Section 43-02-03-16.
 - (d) Plugging and abandoning? Yes—NDAC Section 43-02-03-33. (Includes site reclamation).
 - (e) Saltwater disposal? Yes—NDAC Section 43-02-05-04.
 - (f) Enhanced recovery well? Yes—NDAC Section 43-02-05-04.
- 2. Permit fee:
 - (a) Drilling: \$100.
 - (b) Seismic Exploration: \$100. Regulated by the Industrial Commission, Oil and Gas Division.
 - (c) Recompletion: \$50.
 - (d) Plugging and abandoning: No.
 - (e) Saltwater disposal well to be drilled: \$100.
 - (f) Injection well to be drilled: \$100.
- 3. Require filing report of work performed: Yes—NDAC Section 43-02-03-31.

Vertical Deviation

- 1. Regulation requirement: Yes—NDAC Section 43-02-03-25.

- (a) When is directional survey necessary? On all directionally and horizontally drilled holes. On any well when the location of the bottom of the hole is in doubt.
- (b) Filing of survey required? Yes, the survey contractor must file a certified copy.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes, 50' below Fox Hills Fm—NDAC Section 43-02-03-21.
 - (b) Production casing: Yes—Per field order. Must be set and cemented at a point no higher than the top of the producing formation.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes. Must cement to surface.
 - (b) Production casing: Yes.
 - (c) Setting time: Yes. 12 hours surface casing. Production casing until tail cement reaches a compressive strength of 500 psi.
3. Tubing requirements:
 - (a) Oil wells: Yes—NDAC Section 43-02-03-21. All wells must be tubed with tubing set as near bottom as practicable. Flowing wells to be equipped with packer. Can request waiver.
 - (b) Gas wells: Yes—NDAC Section 43-02-03-21. All wells must be tubed with tubing and packer set as near the bottom as practicable.
 - (c) Saltwater disposal wells: Yes—NDAC Section 43-02-05-06. All wells must be tubed with tubing and packer set immediately above the injection zone.
 - (d) Enhanced recovery: Yes—NDAC Section 43-02-05-06. All wells must be tubed with tubing and packer set immediately above the injection zone.

Completion

1. Completion report required: Yes—NDAC Section 43-02-03-31.
 - (a) Time limit: 30 days except completion reports for discovery wells must be submitted immediately.
 - (b) Where submitted: North Dakota Industrial Commission, Oil and Gas Division.
2. Well logs required to be filed: Yes—NDAC Section 43-02-03-31.
 - (a) Time limit: 30 days.
 - (b) Where submitted: North Dakota Industrial Commission, Oil and Gas Division.
 - (c) Confidential time period: If requested. 6 months.
 - (d) Available for public use: Yes.

- (e) Log catalog available: Yes.
- 3. Multiple completion regulation: Yes—NDAC Section 43-02-03-26.
 - (a) Approval obtained: Multiple completions can be approved by the Director.
- 4. Commingling in well bore: Yes—NDAC Section 43-02-03-42.
 - (a) Approval obtained: Order of the Commission or the Director, after notice and hearing.

Oil Production

- 1. Definition of an oil well: NDAC Section 43-02-03-01. Any well capable of producing oil and which is not defined as a gas well.
- 2. Potential tests required: Yes.
 - (a) Time interval: First 24 hours after completion. Requested info under Completion Report—Form 6.
 - (b) Witness required: No.
- 3. Statewide allowable: Yes—NDAC Section 43-02-03-63. Applicable only if production exceeds demand. Market demand proration. A normal 40-acre proration unit allowable is set by Commission and is uniform for all normal units within all pools to depths of 5,000 feet. Allowables increase with depth below 5,000 feet.
 - (a) Pool allowable: May be set by rule or order of the Commission, after notice and hearing, to prevent waste or to protect correlative rights.
 - (b) Well allowable: May be set by rule or order of the Commission, after notice and hearing, to prevent waste or to protect correlative rights.
 - (c) Exempt allowable: Yes. Under market demand proration, the first 4 wells in a pool may produce 200 b/d. Exemption continues for 18 months or until 5th well is completed.
- 4. Maximum gas-oil ratio: 2,000/1. NDAC Section 43-02-03-39.
 - (a) Provision for limiting gas-oil ratio: Yes. Commission may, after notice and hearing, restrict production from well if deemed necessary to conserve reservoir energy.
 - (b) Exception to limiting gas-oil ratio: Yes. Commission may, after notice and hearing, waive restrictions.
- 5. Bottom-hole pressure test reports required: Yes—NDAC Section 43-02-03-41.
 - (a) Periodical bottom-hole pressure surveys: Yes. Per field order.
- 6. Commingling oil in common facilities: Yes—NDAC Section 43-02-03-48.1. Provided the volume is determined in barrels of oil through meter measurements or tank measurements, and the production from each well can be accurately determined at reasonable intervals. Commingling of production in a central production facility from two or more wells having diverse ownership that is not metered prior to commingling may only be approved by the Commission after notice and hearing.
- 7. Measurement involving meters: Yes—NDAC Section 43-02-03-48.2. Custody transfer meters and allocation meters allowed with calibration requirements.
- 8. Production reports: Yes—NDAC Section 43-02-03-52.
 - (a) By lease: No.
 - (b) By well: Yes.

- (c) Time limit: First day of second month following production.

Gas Production

1. Definition of a gas well: NDAC Section 43-02-03-01. A well producing gas or natural gas from a common source of gas supply as determined by the Commission.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: First 24 hours after completion.
 - (b) Witness required: No.
4. Statewide allowable: No—NDAC Section 43-02-03-69.
 - (a) Pool allowable: Yes. May be set after notice and hearing on the basis of purchaser nominations.
 - (b) Well allowable: Only by order of the Commission after notice and hearing.
 - (c) Exempt allowable: Only by order of the Commission after notice and hearing.
5. Bottom-hole pressure test reports required. Yes—NDAC Section 43-02-03-41.
 - (a) Periodical bottom-hole surveys: Yes, determined by order of the Commission.
6. Commingling of gas in common facilities. NDAC Section 43-02-03-48.1. Only by order of the Commission after notice and hearing.
7. Measurement involving meters: Yes—NDAC Section 43-02-03-14.2. Sales meters and allocation meters allowed with calibration requirements.
8. Production reports: NDAC Section 43-02-03-52.1.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Fifth day of second month following production.

Water Disposal

1. NDAC Section 43-02-05-04. State agencies that control disposal of produced salt water: The North Dakota Industrial Commission, Oil and Gas Division, regulates the subsurface disposal of fluids which are brought to the surface in connection with oil and gas production.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes—NDCC Section 38-08-08.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization: NDCC Section 38-08-09.5.
 - (a) Working interest: 60%.
 - (b) Royalty interest: 60%.

Taxation

Gas gross production tax = \$0.04 per MCF adjusted annually per consumer price index

Gas ad valorem tax = 0.0%

Total gas tax burden = \$0.04 per MCF adjusted annually per consumer price index Gas tax rate for fiscal year 2008 (July 1, 2007 through June 30, 2008) is \$0.1428 per MCF.

Oil gross production tax = 5.0%

Oil ad valorem tax = 0.0%

Oil extraction tax = 6.5%, 4.0%, 2%, or 0.0%

Total oil tax burden = 11.5%, 9.0%, 7%, or 5.0%

1. Tax collecting agency: State Tax Commissioner, State Capitol, Bismarck, ND 58505-0599.
2. How tax is computed: Oil is taxed at 5.0% gross production plus oil extraction levy of either 0.0%, 4.0% or 6.5%. Gas is taxed at \$0.04 per MCF as adjusted annually per consumer price index.
3. Exemptions or exceptions:

Shallow gas produced during the first twenty-four months of production beginning with the date of first sales from a well completed or recompleted in a shallow gas zone is exempt from gross production tax.

Stripper oil is exempt from the oil extraction tax.

There is a fifteen-month exemption from the oil extraction tax for new wells drilled and completed as vertical wells, a twenty four-month exemption for new wells drilled and completed as horizontal wells, and a five-year exemption for new wells drilled and completed within the boundary of an Indian reservation. After the exempt period, the extraction tax rate is 4.0% for all new wells.

Incremental production from a qualifying secondary recovery project is exempt from the extraction tax for five years beginning on the date incremental production begins. Incremental production from a qualifying tertiary recovery project is exempted from the extraction tax for ten years beginning on the date incremental production begins. Thereafter the oil extraction tax rate is 4.0%.

Oil produced from a qualifying two-year inactive well is exempted from the extraction tax for a period of ten years; thereafter the extraction tax rate is 4.0%.

Oil produced from a qualifying horizontal re-entry well is exempted from the extraction tax for a period of nine months after completion; thereafter the extraction tax rate is 4.0%.

Oil produced from a qualifying work-over project is exempt from the extraction tax for a period of twelve months, beginning the third month after the project is completed; thereafter the extraction tax rate is 4.0%.

If a sustained rise in the average price of a barrel of crude oil makes the trigger provision effective, many exemptions and rate reductions become void. If this is followed by a sustained drop in the average price of a barrel of crude that makes the trigger provision ineffective, the exemptions and rate reductions are reinstated. Trigger price for calendar year 2007 is \$42.89 per barrel.

4. Name of Tax: Gross Production and Oil Extraction.
5. Statutory citation: North Dakota Century Code Chapter 57-51 (Gross Production Tax) and North Dakota Century Code Chapter 57-51.1 (Oil Extraction Tax).

Mineral Leasing Information

1. Leasing Method: Oral bidding; but could be done with sealed bids. Sales are generally held the first Tuesday of February, May, August and November.
2. Notice of Method: Sale list that is sent out to approximately 300 companies and individuals that have asked to receive the list. Also, the sale is advertised in various county newspapers.
3. Minimum bidding \$ (per acre): Minimum of \$1.00/acre. The sale list is generated by an interested individual or company nominating a tract for the next available sale. By the nomination, the nominee is agreeing to pay the minimum bid.
4. Qualification of the bidder: No specific qualification. However, any bid can be rejected.
5. State Statutes: NDCC 15-05 and 38-09
6. Maximum acres: 160 acres.
7. Royalty rate: The lease for any tract within three miles of existing production will be issued with a 1/6 royalty provision. Leases outside the three miles will be issued with a 1/8 royalty.
8. Contact: Rick D. Larson
Phone: (701) 328-2800
E-mail: rdlarson@state.nd.us
Website: www.land.state.nd.us

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: North Dakota Department of Health, Division of Air Quality, 918 East Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947, Phone: (701) 328-5188, Fax: (701) 328-5200.
2. Relevant Statute/Regulations: Regulations: North Dakota Radiological Health Rules, North Dakota Administrative Code Article 33-10. Statute: North Dakota Century Code Chapters 23-20, 23-20.1, and 23-20.2
3. Scope: The regulations cover all ionizing radiation sources, including NORM. However, there isn't a specific chapter on NORM in regulations. North Dakota has not adopted regulations equivalent to the CRCPD's Part N.
4. Licensing: Licensing of NORM is handled the same way as licensing of other radioactive materials, using North Dakota Radiological Health Rules chapter 33-10-03, which is based upon the CRCPD's Part C, "Licensing of Radioactive Materials." Also, anyone who owns NORM is considered to be a general licensee and would need to comply with applicable portions of the North Dakota Radiological Health Rules.
5. Cleaning Equipment: No specific standards for cleaning equipment. Would need to obtain a license to provide NORM decontamination services.
6. Disposal of Waste: Must receive approval of North Dakota Department of Health before disposing of NORM. Disposal in a plug and abandon well has been approved in the past; approval is on a case-by-case basis.
7. Subsequent Use of Equipment or Materials: Equipment and materials must be permanently decontaminated below or equal to the standards in Appendix F of Chapter 33-10-04.1. A survey must be made after decontamination and the North Dakota Department of Health and subsequent transferee or owner must be provided with a copy of the survey. Equipment or materials can't be sold, leased, or transferred until the decontamination survey has been verified and accepted by the North Dakota Department of Health.
8. Release/Sale of NORM-Contaminated Land: Must be 5 picocuries of radium or less per gram of dry soil. Results of

surveys must be provided to North Dakota Department of Health and property owner or subsequent tenant or transferee. Property can't be vacated, sold, or transferred until a decontamination survey has been verified and accepted by North Dakota Department of Health.

9. Projected Volume of stored NORM in the State: Unknown.
10. Contact: Ken Wangler
Phone: (701) 328-5188
E-mail: kwangler@state.nd.us
Website: www.health.state.nd.us/ehs

OHIO

Administration

1. State agency: Department of Natural Resources, Division of Mineral Resources Management, 2045 Fountain Sq. H-3, Columbus, OH 43229-6693. (Chapter 1509, Ohio Revised Code). Phone (614) 265-6633.
2. Docketing procedure: Upon the filing of an appeal, the Commission shall promptly fix the time and place at which the hearing on the appeal will be held.
 - (a) Orders: The Chief may issue orders, effective without prior hearing. Such order is an adjudication order. Any appeal to such order must be made to the Oil and Gas Commission within 30 days of the receipt of the order and notice of the appeal must be filed with the Chief within three (3) days after the appeal is filed with the Commission.
 - (b) Notice: The Commission must give at least 10 days written notice by mail of the time set for the appeal.

Bond

1. Compliance bond required: Any owner before being issued a permit shall execute and file with the Division of Mineral Resources Management a Surety Bond.
2. Conditions of bond: The Surety Bond is conditioned on compliance with the well plugging and land restoration requirements of the law. Section 1509.07 O.R.C. The Surety Bond is conditioned on compliance with the restoration requirements of Section 1509.072, plugging requirements of Section 1509.12, permit provisions of Section 1509.13 of the Revised Code, and all rules and orders of the Chief of the Division of Mineral Resources Management relating thereto.
 - (a) Amount per well: \$5,000 individual.
 - (b) Amount of blanket bond: \$15,000.
 - (c) Financial statements are accepted in limited situations in lieu of bond.
 - (d) Landowners with one well for their own use can file a one time filing fee of \$50.

Spacing

1. Spacing requirements: Rule 1501: 9-1-04. No distinction is made between oil wells or gas wells. The general spacing regulations are as follows:
 - (a) Density: Wells drilled to a pool from zero to 1,000 feet in depth require a subject tract or drilling unit containing not less than one acre.

Wells drilled to a pool from 1,000 to 2,000 feet in depth require a subject tract or drilling unit containing not less than 10 acres.

Wells drilled to a pool from 2,000 to 4,000 feet require a subject tract or drilling unit containing not less than 20 acres.

Wells drilled to a pool from 4,000 feet or deeper require a subject tract or drilling unit containing not less than 40 acres.
 - (b) Lineal: Well must be located not less than 200 feet from any well drilling to, producing from, or capable of producing from the same pool. Well must be located not less than 100 feet from any boundary of the subject

tract or drilling unit. (0 to 1,000 feet in depth)

Well must be located not less than 460 feet from any well drilling to, producing from, or capable of producing from the same pool. Well must be not less than 230 feet from any boundary of the subject tract or drilling unit. (1,000 to 2,000 feet in depth)

Well must be located not less than 600 feet from any well drilling to, producing from, or capable of producing from this same pool. Well must be located not less than 300 feet from any boundary of the subject tract or drilling unit. (2,000 to 4,000 feet in depth)

Well must be located not less than 1,000 feet from any well drilling to, producing from, or capable of producing from the same pool. Well must be located not less than 500 feet from any boundary of the subject tract or drilling unit. (4,000 feet or deeper)

2. Exceptions:

- (a) Basis: For offset wells and if an applicant can demonstrate that such exception will protect correlative rights and/or promote conservation by permitting oil and gas to be produced which could not otherwise be produced.
- (b) Approval: Exceptions can be granted by the Chief. Establishing temporary minimum well spacing in the vicinity of discovery wells. Rule 1501: 9-1-04 (D) requires approval of the Technical Advisory Council.

Pooling

- 1. Authority to establish voluntary: Yes. Section 1509.26 O.R.C.
- 2. Authority to establish compulsory: Yes. Section 1509.27 O.R.C.

Drilling Permit

1. Require permits for:

- (a) Drilling a producing or service well: Yes.
- (b) Seismic drilling: No.
- (c) Recompletion: Yes. Permit required for reopen, deepen, and plug-back.
- (d) Plugging and abandoning: Yes.

2. Permit fee:

- (a) Drilling: \$250 (in non-urban areas). In Townships with unincorporated population exceeding 5,000 but less than 10,000: \$500, where unincorporated population exceeds 10,000 but is less than 15,000: \$750 and where unincorporated population exceeds 15,000 and in all municipal corporations: \$1000 (Expedited permit seven day processing extra \$500 fee required.) 1509.06 O.R.C.
- (b) Seismic drilling: No.
- (c) Recompletion: \$250 for reopen, deepen, and plug-back. No fee for recompletion in same zone.
- (d) Plugging and abandoning: \$50 for producer; none for dry hole. (Expedited permit one-five day processing extra \$250 fee required).

3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? Anytime a well bore is deviated. A well bore may not be deviated without prior approval.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes.
 - (b) Production casing: No.
2. Minimum amount of cement required:
 - (a) Surface casing: No - Cable Tool, Yes - Rotary Tool.
 - (b) Production casing: No.
 - (c) Setting time: No, Unless specified by permit conditions.
3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes.
 - (a) Time limit: 30 days.
 - (b) Where submitted: Division of Mineral Resources Management.
2. Well logs required to be filed: Yes (If any logs are run).
 - (a) Time limit: 30 days.
 - (b) Where submitted: Division of Mineral Resources Management.
 - (c) Confidential time period: Six months and an additional 6 months if requested in writing (for exploratory wells only).
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes, from the Ohio Division of Geological Survey.
3. Multiple completion regulation: No regulation but each case is considered on its own merits.
 - (a) Approval obtained:
4. Commingling in well bore: No regulation but each case is considered on its own merits.
 - (a) Approval obtained:

Oil Production

OH

1. Definition of an oil well: Do not have one.
2. Potential tests required: No.
 - (a) Time interval: No.
 - (b) Witness required: No.
3. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: No.
 - (b) Exception to limiting gas-oil ratio: No.
5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: No.
7. Measurement involving meters: No.
8. Production reports: Yes.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Annually.

Gas Production

1. Definition of a gas well: Do not have one.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes, must be submitted with well completion record.
 - (a) Time interval: 30 days.
 - (b) Witness required: No.
4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.

- (c) Exempt allowable: No.
- 5. Bottom-hole pressure test reports required: No.
- (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: No.
- 7. Measurement involving meters: Yes.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Annually (March 15).

Water Disposal

- 1. State agencies that control disposal of produced salt water: Department of Natural Resources, Division of Mineral Resources Management.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 65%. Section 1509.28 O.R.C.
 - (b) Royalty interest: 65%. Section 1509.28 O.R.C.

Taxation

Gas severance tax = 2.5 cents per MCF gas
 Gas ad valorem tax = variable by county
 Energy and education = \$.001/MCF (one tenth of one cent)
 Total gas tax burden = 2.6 cents per MCF gas

Oil severance tax = 10 cents per barrel of oil
 Oil ad valorem tax = variable by county
 Energy and education = \$.01 bbl/oil
 Total oil tax burden = 11 cents per barrel of oil

- 1. Tax collecting agency: Severance tax - Department of Taxation, Highway Use, Motor Fuel and Excise Tax, Box 530, Columbus, OH 43216. Ad Valorem tax - Auditor of county in which wells are located.
- 2. How tax is computed: Severance tax - 10 cents per BBL of oil and 2.5 cents per MCF gas. Of the money received by the treasurer of state from the severance tax levied on oil and gas, ninety percent is credited to an oil and gas well fund. Ten percent of the severance tax levied is credited to a state geological mapping fund. Ad valorem tax – Oil and gas contained or produced in or upon any lot or parcel of land is assessed for purposes of ad valorem taxation by the county auditor or each county. The aggregate valuation of the land and minerals therein will be taxed at a varying rate depending on the tax rate in effect for each county.

3. Exemptions or exceptions: Severance tax – Landowners owning a well(s) on their land for natural gas production for their own use that mounts to less than \$1,000 of yearly cumulative market value is not subject to severance tax. There is no such exemption for oil production. Ad valorem tax – Flush production is subject to a reduced rate of taxation.
4. Name of tax: Severance and Ad Valorem.
5. Statutory citation: Section 5749 O.R.C. - Severance; Section 5713.05 O.R.C. - Ad Valorem; Section 1510. O.R.C. - Energy Education.

Land Leasing Information

No regulations at this time

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Natural Resources, Division of Mineral Resources Management, 1855 Fountain Sq. Ct., Bldg. H, 2nd Floor, Columbus, OH 43224. Phone: (614) 265-6633, Fax: (614) 268-4316.
2. Relevant Statute/Regulations: Ohio has no rules specific to oil and gas NORM.
3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Respondent: Scott Kell

OKLAHOMA

Administration

1. State agency: Oklahoma Corporation Commission, Oil and Gas Conservation Division, P.O. Box 52000, Oklahoma City, OK 73152-2000. Phone: (405) 521-2302. Fax: (405) 521-3099. Web: www.occeweb.com. The Commission's Oil and Gas Conservation Rules are contained in OAC (Oklahoma Administrative Code) 165:10-1-1, et seq., and its Rules of Practice appear in OAC 165:5-1-1, et seq.
2. Docketing procedure: Ordinarily 80 to 100 unprotested cases per day are set on the administrative law judges' dockets for hearings on Monday and Tuesday. Protested cases are set for hearing on Wednesday through Friday which encompass 10 to 30 cases per week. The Pollution and Enforcement Docket is held on Wednesday and Friday with approximately 20 cases per week. Emergency and motion dockets are held on Monday and Tuesday with approximately 5 to 10 emergency applications and 10 to 20 motions set on these dockets. Matters set for hearing in the Commission's Tulsa office correspond to the foregoing docket dates for its Oklahoma City office, with the exception of the Pollution and Enforcement docket, which occurs on Tuesday in the Commission's Tulsa office. The Commission's Tulsa office is located at 440 South Houston, Suite 114, Tulsa, OK, 74127. Phone: (918) 581-2296. Fax: (918) 581-2597.
 - (a) Notice: Fifteen days notice is required for many hearings on applications. Five days notice is required for emergency and motion hearings unless otherwise specified.
 - (b) Fees: A \$100.00 filing fee is assessed for conservation docket and pollution docket base applications. Filing fees of \$1,000.00 are charged for applications pertaining to commercial disposal wells, commercial earthen pits and commercial soil farming. The filing fee for a permit to drill is \$175.00, and the filing fee for an emergency walk through permit to drill is \$500.00. The permit filing fee for a one time land application of water based fluids is \$100.00, and the filing fee for an emergency walk through permit for a one time land application of water based fluids is \$200.00. Additional fees for motions and emergency applications filed pursuant to the base application are not required.

Surety

1. Surety required: Category A: Financial Statement showing net worth in Oklahoma of not less than \$50,000.00; Category B: Corporate Surety Bond, Irrevocable Commercial Letter of Credit, Bank Joint Custody Receipt, Certificate of Deposit, Cashier's Check, Cash, or other negotiable instrument in the minimum amount of \$25,000.00. The amount of Category B surety may be set higher at the discretion of the Director of the Conservation Division. The Commission is authorized to establish Category B surety in an amount greater than \$25,000.00 based upon the past performance of the operator and its insiders and affiliates regarding compliance with the laws of Oklahoma, and compliance with any rules promulgated thereto including, but not limited to, the drilling, operation and plugging of wells, closure of surface impoundments or removal of trash and equipment. For good cause shown concerning pollution or improper plugging of wells by an operator posting either Category A or Category B surety or by an insider or affiliate of such operator, the Commission, upon application of the Director of the Conservation Division after notice and hearing, may require the filing of additional Category B surety in an amount greater than \$25,000.00 but not to exceed \$100,000.00. See Okla. Stat. Tit. 52 § 318.1 and OAC 165:10-1-10, et seq.
2. Conditions of surety and operator's agreement: That all wells will be drilled, operated and plugged in accordance with Rules and Regulations of the Commission and Oklahoma law. Financial statements must be updated annually. Letters of Credit must be valid for at least one year and updated annually. Certificates of Deposit must be valid for at least a minimum of one year. An operator's agreement must accompany any form of Surety submitted and updated annually. Surety is used for plugging wells, closure of surface impoundments and removal of trash and equipment.
 - (a) Amount per well: If statewide plugging liability is less than \$25,000.00, Category B surety can be submitted based on estimated cost of plugging for each well operated. The estimated cost of plugging and abandonment shall not include any salvage value as to recoverable casing, tubing or wellhead equipment. Surety shall be increased as additional wells are added to the responsibility of the operator and may be decreased as included wells are properly plugged and abandoned.

- (b) Amount of blanket bond: Corporate Surety Bond amount: \$25,000.00. Irrevocable Commercial Letter of Credit amount: \$25,000.00. Financial Statement minimum net worth amount: \$50,000.00. Bank Joint Custody Receipt, Certificate of Deposit or cash amount: \$25,000.00.
- (c) Performance bond - Seismic Operators: \$50,000.00.
- (d) Financial surety guarantee-stratigraphic test hole operations-in accordance with OAC 165:10-1-10.

Spacing

1. Spacing requirements: Not mandatory. If desired, upon application, notice (to each person or governmental entity having the right to participate in production from the proposed drilling and spacing unit or the existing drilling and spacing unit and publication notice in a newspaper of general circulation published in Oklahoma County and in each county in which lands embraced in the application are located) and hearing.
 - (a) Standard square drilling and spacing units: 10, 40, 160, or 640 acres. Standard rectangular drilling and spacing units: 20, 80 or 320 acres. See OAC 165:10-1-22. *Drilling additional well into one unit spacing can be permitted by hearing only.
 - (b) Permitted well locations: The center of the unit for any standard square drilling and spacing unit. The permitted well location within standard rectangular drilling and spacing units shall be the centers of alternate square tracts constituting the units (alternate halves of the unit). Well will be deemed drilled at the permitted location if drilled within the following tolerance areas: (A) Not less than 165 feet from the boundary of any standard 10-acre drilling and spacing unit or the proper square 10-acre tract within any standard 20-acre drilling and spacing unit. (B) Not less than 330 feet from the boundary of any standard 40-acre drilling and spacing unit or the proper square 40-acre tract within any standard 80-acre drilling and spacing unit. (C) Not less than 660 feet from the boundary of any standard 160-acre drilling and spacing unit or the proper square 160-acre tract within any standard 320-acre drilling and spacing unit. (D) Not less than 1320 feet from the boundary of any standard 640-acre drilling and spacing unit. See OAC 165:10-1-24.
 - (c) Horizontal drilling: A horizontal well is a well drilled, completed, or recompleted in a manner in which the horizontal component of the completion interval in the geological formation exceeds the vertical component thereof and which horizontal component extends a minimum of 150 feet in the formation. For information concerning drilling and producing a horizontal well on a lease basis or in a conventional drilling and spacing unit, creation of horizontal well units, well location requirements, determination of unit size and allowable, horizontal well spacing requirements, etc. refer to OAC 165:10-3-28 of the Commission's Oil and Gas Conservation rules, and OAC 165:5-7-6, 165:5-15-3, 165:5-15-8 and 165:5-15-9 in the Commission's Rules of Practice for additional requirements regarding horizontal wells.
2. Exceptions: Yes.
 - (a) Basis: To prevent waste, protect correlative rights, to encounter the edge of a known producing reservoir, or because of surface obstructions.
 - (b) Approval: Upon application, notice (including written notice to offset operators and working interest parties toward whom the location is to be moved) and hearing. An allowable penalty may be imposed.
3. Dewatering units: The Commission may establish drilling and spacing units not to exceed 160 acres in size regarding reservoir dewatering to extract oil from reservoirs having initial water saturations at or above 50%. See OAC 165:10-15-18 regarding production tests and reports for reservoir dewatering oil spacing units.

Pooling

1. Authority to establish voluntary: Yes, by private contract.
2. Authority to establish compulsory: Yes, for owners of the right to drill who cannot agree as to how the unit should be

developed. Spacing is a prerequisite. 52 O.S.87.1(e). See OAC 165:5-7-7, 165:5-15-3 and OAC 165:10-25-1, et seq.

Drilling Permit

1. Require permits for: (See OAC 165:10-3-1) (See OCC's website for instructions on electronic submissions of permits to drill)
 - (a) Drilling a producing, injection, salt water disposal, or service well: Yes.
 - (b) Seismic exploration activities and stratigraphic test hole operations: Yes. See OAC 165:10-7-31.
 - (c) Recompletion: Yes.
 - (d) Reentry: Yes.
 - (e) Deepening an existing well: Yes.
2. Application fee:
 - (a) Drilling: \$175.00 fee for standard processing. \$500.00 fee if processed on a walk through basis.
 - (b) Seismic operations: None.
 - (c) Recompletion: \$175.00 fee for standard processing. \$500.00 fee if processed on a walkthrough basis.
 - (d) Reentry: \$175.00 fee for standard processing. \$500.00 fee if processed on a walkthrough basis.
 - (e) Deepening an existing well: \$175.00 fee for standard processing. \$500.00 fee if processed on a walkthrough basis.
 - (f) Stratigraphic test hole operations: \$175.00 fee for standard processing. \$500.00 fee if processed on a walkthrough basis.

Seismic

1. All applicants, before commencing any seismic operations, must:
 - (a) Register with the OCC and include a permanent mailing address.
 - (b) Post a financial surety guarantee with the OCC.
 - (c) Provide to the OCC the name and business or field address of the contractor responsible for the operations being conducted.
 - (d) Notify all surface owners of property where seismic operations will occur at least 15 days prior to commencement of operations. The notice shall include a copy of the oil or gas lease or seismic permit or other legal instrument of similar nature authorizing the use of the surface for seismic operations and shall include the name of the company which is conducting the seismic operations and anticipated date of commencement of operations.
2. Applicants must obtain a permit from the Conservation Division for seismic operations on a Form 1000S.
 - (a) Permit must be obtained for each seismic operation.
 - (b) Attach a pre-plat of the operation area.
 - (c) Post a performance bond in the amount of \$50,000.00, or other form of surety in an amount approved by the Conservation Division.
 - (d) Permits are good for one (1) year from the date of issuance.

- (e) Commission shall approve or deny application within 30 days of receipt of the application.
- (f) Persons without valid permit can be fined \$1,000. See OAC 165:10-7-31 concerning seismic and stratigraphic operations, and OAC 165:10-7-15 regarding drilling or seismic activity near superfund sites or hazardous waste facilities.
- (g) Written notice of commencement of seismic operation to be filed with the Conservation Division within fourteen days after commencement of such operation.
- (h) No seismic shot hole blasting shall be conducted within 200 feet of any habitable dwelling, building or water well without written permission from the owner of the property or within 500 feet of any superfund site or hazardous waste facility.
- (i) Within 30 days after completing a seismic operation, the applicant receiving the permit shall submit a copy of the approved Form 1000S certifying the plugging of all seismic shot holes in compliance with OAC 165:10-7-31 and a post-plat or acceptable form of survey showing the actual location of all seismic shot holes.

Stratigraphic test hole operations

1. All applicants, before commencing any stratigraphic test hole operations, must:
 - (a) Register with the OCC and include a permanent mailing address.
 - (b) Post a financial surety guarantee with the OCC in accordance with OAC 165:10-1-10.
 - (c) Notice to surface owners must be given according to OAC 165:10-3-1(g).
2. Applicants must obtain a permit from the Conservation Division for stratigraphic test hole operations on a Form 1000.
 - (a) Permit must be obtained for each stratigraphic test operation.
 - (b) Surface casing requirements shall be met according to OAC 165:10-3-4, storage and disposal of fluids associated with the drilling of stratigraphic test holes shall meet the requirements of OAC 165:10-7-16, the duty to plug and abandon, to notify the Conservation Division prior to plugging stratigraphic test holes, the manner of plugging and plugging certification shall be in accordance with OAC 165:10-11-3, OAC 165:10-11-4, OAC 165:10-11-6 and OAC 165:10-11-7 unless applicant can demonstrate to the Conservation Division's District Office that another method will provide sufficient protection to groundwater supplies and long term land stability.
 - (c) Permits are good for six (6) months from the date of issuance.
 - (d) Commission shall approve or deny application within 30 days of receipt of the application.
 - (e) Persons without valid permit can be fined \$1,000. See OAC 165:10-7-31 concerning seismic and stratigraphic operations, and OAC 165:10-7-15 regarding drilling or seismic activity near superfund sites or hazardous waste facilities.
 - (f) Written notice of spudding of stratigraphic well to be filed with the Conservation Division within fourteen days after spudding of well.

Casing, Cementing, and Wellhead Equipment (OAC 165: 10-3-4)

1. Minimum surface casing required: Unless an alternate casing program is authorized by the OCC, suitable and sufficient surface casing shall be run and cemented from bottom to top with a minimum setting depth which is the greater of ninety feet below the surface, or fifty feet below the base of treatable water.
2. Wells which penetrate unitized common sources of supply: Each newly drilled or reentered well which penetrates a common source of supply in which enhanced recovery operations are being conducted shall be properly cased

and cemented from not less than 100 feet below to not less than 100 feet above each unitized common source of supply to prevent migration of formation fluids and contain formation pressure. In the event the well is to be plugged without being cased, the well shall be properly cemented over the aforementioned interval(s) during plugging procedures.

3. Wellhead equipment: Except in proven areas where less equipment is known to be adequate, every drilling well shall be equipped with a mastergate, or its equivalent, or an adequate blowout preventer. A flow line valve of proper size and working pressure shall be attached.
4. Minimum amount of cement required for additional casing strings: If additional casing other than surface casing is run, except for temporary purposes, it shall be run, set, and cemented with a calculated volume of cement sufficient to fill the annular space behind the casing string from the base of the casing string to a minimum height which is the greater of 5% of the depth to which the casing string is set or a height of 200 feet. Wells approved for horizontal completion are exempt upon approval of the Conservation Division.
5. Pressure testing of casing strings: Before drilling the cement plug in a casing string, the operator shall pressure test the installed casing for 30 minutes at a minimum pressure which is the lesser of the surface gauge pressure equal in pounds per square inch to 0.2 of the length of the casing in feet or 1500 psig. During the 30 minute test, if the surface pressure drops 10% or more, the operator shall repair and retest the casing until the aforementioned requirements are met, or plug the well according to Commission rules.

Completion

1. Completion report required: Yes, by Well Completion Report (Form 1002A).
 - (a) Time limit: Within 30 days after completion of operations, regardless of whether or not the well was completed as a dry hole, producer, injection, disposal or service well. An amended Completion Report shall be filed with the Commission within 30 days after completion of operations to reenter, recompleat and/or convert to an injection or disposal well. The Conservation Division shall not assign an allowable to a well without a current Completion Report being on file with the Conservation Division. OAC 165:10-3-25. The operator of the well shall also submit, along with its Form 1002A Completion Report, Form 1002C Cementing Report(s) describing all cementing operations on surface, intermediate and production casing strings, including multistage cementing jobs. OAC 165:10-3-4(i).
 - (b) Where submitted: Oklahoma Corporation Commission, Oil and Gas Conservation Division, Oklahoma City office.
2. Well logs required to be filed: Yes, resistivity and porosity type wireline logs, if run. Resistivity and porosity type wireline logs include, but are not limited to, spontaneous potential, induction, laterolog and density and gamma ray neutron logs. OAC 165:10-3-26.
 - (a) Time limit: Within 60 days from the earlier of the date of completion of the well or the date the last formation evaluation type wireline log was run.
 - (b) Where submitted: Oklahoma Corporation Commission, Oil and Gas Conservation Division, Oklahoma City office.
 - (c) Confidential time period: Yes, if requested and Form 1002B timely filed. Held confidential for one year from the date the last log was run on the well. Optional six months' extension may be granted upon written request. OAC 165:10-3-26.
 - (d) Available for public use: Yes, unless confidential, then only after expiration of confidential time period.
 - (e) Log catalog available: No.
3. Multiple zone completion and production regulations: Yes. See OAC 165:10-3-35, 165: 10-3-36, 165:10-3-37, 165:10-3-38 and 165:5-7-22.

- (a) Approval for multiple zone completions: Administratively, subsequent to submission of Form 1023. Hearing required only if protested or if required by the Commission.
- 4. Commingling of production: Yes. See OAC 165:10-3-39 and 165:5-7-24.
 - (a) Approval obtained: Administratively, subsequent to submission of Form 1023. Hearing required only if protested or if required by the Commission.
- 5. Venting or flaring: See OAC 165:10-3-15, and also operation in hydrogen sulfide areas addressed in OAC 165:10-3-16.

Oil Production

- 1. Definition of an oil well: GOR (Gas-Oil Ratio) of less than 15,000 to one. Classification is for allowable purposes. OAC 165:10-13-2. GOR means the ratio of the gas produced in standard cubic feet to one barrel of oil produced during any stated period. Condensate and load oil excepted under OAC 165:10-13-6 shall not be considered as oil for purposes of determining GOR. OAC 165:10-1-2.
- 2. Potential and production tests required: Yes. See OAC 165:10-13-3, OAC 165:10-15-6 (discovery oil pools), OAC 165:10-15-10 (allocated oil wells), OAC 165:10-15-13 (unallocated oil wells), OAC 165:10-15-15 (enhanced oil recovery projects), OAC 165:10-15-17 (excessive water exempt oil projects) and OAC 165:10-15-18 (reservoir dewatering oil spacing units).
 - (a) Time interval: 30 days after completion of the well (discovery oil pool); 30 days after the earlier of making the election, completion of the well, or recompletion of the well (unallocated oil wells).
 - (b) Witness required: Operator shall give 24 hour notice of the opportunity to witness the initial test to the Conservation Division and the offset operator(s) producing from the same pool.
- 3. Allowables. See OAC 165:10-15-5 (discovery oil allowables), 165:10-15-9 (allocated oil allowables), 165:10-15-12 (unallocated oil allowables), 165:10-15-14 (enhanced oil recovery project allowables), 165:10-15-16 (excessive water exempt oil project allowables) and 165:10-15-18 (allowables for reservoir dewatering oil spacing units).

Gas Production

- 1. Definition of a gas well: GOR (Gas-Oil Ratio) of 15,000 to one or more. Classification is for allowable purposes. OAC 165:10-13-2.
- 2. Initial potential tests: Yes, Form 1016.
 - (a) Time interval: The initial test for all gas wells shall be run into the pipeline within 30 days and test results filed within 45 days after the date of first sales of gas. OAC 165:10-17-6.
 - (b) Witness required: Regarding initial tests for special allocated gas wells, the operator of the well shall provide 24 hours notice to the Conservation Division of its intent to run an initial test in order to give the Conservation Division the opportunity to witness said test, but in no case shall the operator be precluded from performing said test and filing the results as provided above. Initial tests for special allocated gas wells need not be witnessed, nor signatures obtained, if witnessed, in order for the Conservation Division to assign an allowable to said well. Initial tests for unallocated gas wells with calculated open flow of less than two million cubic feet per day are exempt from witnessing by Conservation Division personnel. OAC 165:10-17-6.
- 3. Allowables for unallocated gas wells: The allowable is established in a semiannual proration hearing by the Commission and currently is 65% of WHAOF or 2,000 MCF/d, whichever is greater.

Depending upon market demand considerations, these allowable percentages are subject to change in future years.

- (a) Pool allowables: Yes-allocated, special allocated and unallocated pools.
- (b) Well allowable: Allowables for allocated pools are addressed in OAC 165:10-17-8. Special allocated gas pool allowables are dealt with in OAC 165:10-17-9, and allowables for unallocated gas wells appear in OAC 165:10-

17-11.

- (c) Natural gas priority schedule: Any common purchaser as defined in 52 O.S. § 240 shall purchase all the gas which may be offered for sale and which may reasonably be reached by its trunk lines or gathering lines, without discrimination in favor of one producer as against another or in favor of any one source of supply as against another, except as authorized by the Commission as follows. In the interest of the prevention of waste and protection of correlative rights, the following priority schedule shall be implemented by any first purchaser of gas whenever the permitted production from all wells in any common source of supply in its system in this State, including gas which is processed, is in excess of that purchaser's reasonable market demand; provided, however, if the first purchaser does not contractually control wellhead production, the first taker of gas shall be responsible for implementation of the following priority schedule (OAC 165:10-17-12):
 - (1) Hardship and distressed wells.
 - (2) Enhanced recovery wells.
 - (3) Wells producing casinghead gas and associated gas.
- 4. Bottom-hole pressure test reports required: No.
 - (a) Periodic bottom-hole pressure surveys: No.
- 5. Commingling of gas in common facilities: Yes, if approved by Oklahoma Tax Commission.
 - (a) Commingling of gas zones in wellbore: Yes. See OAC 165:10-3-39 and 165:5-7-24.
 - (i) Approval obtained: Administratively, subsequent to submission of Form 1023. Hearing required only if protested or if required by the Commission.
- 6. Measurement involving meters and recorders: Yes. See OAC 165:10-17-5.
- 7. Production reports: Yes.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Reporting party: Measurer of gas meter.
 - (d) Time limit: Last day of succeeding month.

Underground Injection Wells

- 1. The OCC regulates underground injection wells, which are classified as follows:
 - (a) Enhanced recovery injection wells-wells in which fluids are injected to increase the recovery of hydrocarbons.
 - (b) Disposal wells-wells in which fluids brought to the surface in connection with oil or natural gas production are injected, for purposes other than enhanced recovery.
 - (c) Storage wells-wells used to inject, for storage purposes, hydrocarbons which are liquid at standard temperature and pressure.
 - (d) Simultaneous injection wells-wells which inject or dispose of salt water at the same time they are producing oil and/or gas to the surface.
- 3. See OAC 165:10-5-1, et seq. and OAC 165:5-7-27.

Unitization

1. Unitized management of a common source of supply: Yes, for enhanced recovery. See Okla. Stat. Tit. 52 § 287.1 et seq., OAC 165:5-7-20 and OAC 165:5-15-2.
2. Minimum percentage of ratification or approval regarding plan of unitization:
 - (a) Not less than 63% by lessees of record of the unit area affected thereby.
 - (b) Not less than 63% by owners of record (exclusive of royalty interests owned by lessees or by subsidiaries of any lessee) of the normal 1/8 royalty interest in and to the unit area.
3. Allowable: Based on capacity of unit to produce. See OAC 165:10-15-14.
4. Production test and reports for enhanced oil recovery projects: See OAC 165:10-15-15.
5. Injection Well: Permit to individual well.
6. Mechanical integrity tests: Required initial tests and subsequent tests-see OAC 165:10-5-6.
7. Unitized management of a common source of supply-brine and associated gas. See OAC 165:5-7-21.

Seeping Natural Gas Program

1. Coordination. The Commission coordinates response efforts when notified of an occurrence of seeping natural gas. The Commission enlists private industry, state, county, municipal and local government official entities as needed to aid the Commission in investigating, identifying and abating the hazard, and the Commission can require a utility to run tests to reevaluate the occurrence as to the utility's lines and equipment.
2. Jurisdiction. The Commission is authorized to promulgate and enforce rules and to issue and enforce orders pertaining to seeping natural gas pursuant to Okla. Stat. Tit. 52 § 317.1. The Commission's rules regarding its Seeping Natural Gas Program appear in OAC 165:10-12-1, et seq. Such rules not only establish procedures for the investigation of seeping natural gas, but also provide for the administration of the Seeping Natural Gas Fund so as to provide funding to eligible property owners for the mitigation of seeping natural gas on their property if the Commission is unable to abate the hazard of a seeping natural gas occurrence by issuing an order to a responsible person or by plugging a well.

Taxation

Gas gross production tax = 7.0%
 Gas ad valorem tax = Varies by county
 Petroleum excise tax = 0.095 of 1%
 OERB voluntary contribution = 0.1 of 1%
 Marginal Well Commission = \$0.001 per MCF

Oil gross production tax = 7.0%
 Oil ad valorem tax = Varies by county
 Oil excise tax = .095 of 1.0%
 OERB voluntary contribution = 0.1 of 1%
 Marginal Well Commission = \$0.002 per barrel

1. Tax collecting agency: Gross Production Division, Oklahoma Tax Commission, 409 N. E. 28th Street, Third Floor, Oklahoma City, OK 73105.
2. How tax is computed: Gross Production Tax - 7%; Petroleum Excise Tax - .095% of 1.0%. There are also two voluntary contributions. One is the Oklahoma Energy Resources Board (OERB) voluntary contribution and is .1 of 1% (1 mill). The other is handled by the Oklahoma Commission on Marginally Producing Oil and Gas Wells and is 0.2 cents per

barrel liquid and 0.1 cent per 10,000 feet of gas. The voluntary contributions are paid up front (as the product is sold) and producers can, but seldom do, request a refund of these contributions from the respective boards in March/April each year.

3. Exemptions or exceptions: There is a tax exemption for enhanced recovery projects on qualified incremental increase in production, re-established production from qualified inactive wells, production from qualified deep wells, and production from qualified horizontal wells. Projects must be qualified by the Oklahoma Corporation Commission through application.
4. Name of tax: Gross Production Tax, and Petroleum Excise Tax.
5. Statutory citation: Gross Production Tax - Oklahoma Statutes Title 68, Section 1001; Oil Excise Tax - Oklahoma Statutes Title 68, Section 1101.

Land Leasing Information

1. Leasing Method: Public sealed competitive bids. Also have auctions where 5 year lease contracts are sold, these auctions are done every October.
2. Notice Method: Notice of such sale to be published for 30 days in a newspaper of general circulation in the county where such lands are situated and in a newspaper of general circulation in the State of Oklahoma.
3. Minimum bidding \$ (per acre): No less than \$5.00 per acre, except in a special lease sale. Sometimes land is appraised at a higher fair market value, in these instances the minimum bidding may be higher.
4. Qualification of the bidder: Responsible bidder
5. State Statutes: OK ST Title 64
§92
§281
§285
Rules and Reg.
385:15-1-3~12
6. Maximum acres: 160 acres
7. Contact: Pary Shofner
pary.shofner@clo.state.ok.us
phone: (405) 604-8160

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environmental Quality, Radiation Management Section, 1000 N.E. 10th St., Oklahoma City, OK 73117. Phone: (405) 271-7484.
2. Relevant Statute/Regulation: Oklahoma Department of Quality has no rules to specifically address NORM. Existing radiation rules are interpreted on a case-by-case basis as necessary.
3. Scope: NORM rules have been proposed by industry, but exact scope and content are influx.
4. Licensing: No rules at this moment
5. Cleaning Equipment: no guidance published
6. Disposal of waste: Solid waste rules prohibit disposal of solid waste landfills (RCRA landfills).

7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land: No policy
10. Projected Volume of stored NORM in the State: No estimate at this time
11. Respondent: Mike Broderick, Ralph Johnson

OREGON

Administration

NOTE: The Oregon Legislature passed House Bill 3188 and upon the Governor's signature, became effective June 27, 2007. The bill will likely cause numbering changes, and as a result, references to Oregon Revised Statutes and Oregon Administrative Rules will likely change. The main provisions of the bill are:

- Permit fees increase.
- Improve environmental protection by the requirement of a detailed reclamation plan to be submitted with the application.
- Upgrading language to be consistent with the APA.
- Interagency coordination.
- Clarification of technical terms.

The updated statutes are anticipated to be available around January 2008. The updated administrative rules will likely be available in February or March 2008. The Enrolled House Bill 3188 may be viewed online at:

<http://www.leg.state.or.us/07reg/measpdf/hb3100.dir/hb3188.en.pdf>

1. State agency: Department of Geology and Mineral Industries (DOGAMI), 229 Broadalbin Street SW, Albany OR 97321. Phone (541) 967-2080. FAX: (541) 967-2075.
2. Docketing procedure: Hearings according to Oregon Administrative Law ORS 183, notice period 10 days, published in newspaper of general circulation. Hearings to be held for promulgating rules or orders. ORS 520.105 and ORS 520.115.
 - (a) Emergency orders: Yes, for a limited period of time.
 - (b) Notice: 30 days - by the Department issuing the rule or order.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: Compliance with rules and regulations of the department.
 - (a) Amount per well: \$10,000, less than 2000'; \$15,000, well 2,000' to 5,000'; \$25,000 more than 5000'.
 - (b) Amount of blanket bond: \$100,000 minimum and must equal the individual well bond amounts.
 - (c) Amount per seismic drilling program: \$50,000. This may be waived if operator has blanket bond.

Spacing

1. Spacing requirements: Yes. Rules 632-10-156 and 632-10-157.
 - (a) Basis: Special rules for fields will be adopted by the Board, if a hearing is required.
 - (b) Approval: By the State Geologist if no hearing is required. By the Governing Board of the department if a hearing is required.

Pooling

1. Authority to establish voluntary: Yes. ORS 520.240.

2. Authority to establish compulsory: Yes. Rule 632-10-161, ORS 520.220. Compulsory unitization - small tracts.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes. Rule 632-10-010, ORS 520.025.
 - (b) Seismic drilling: Yes. Rule 632-15-015, ORS 520.095.
 - (c) Recompletion: Yes. Rule 632-10-010.
 - (d) Plugging and abandoning: Yes. Rule 632-10-198.
2. Permit fee:
 - (a) The application fee for a permit to drill a well is \$2,000.
 - (b) The fee for a request to extend the period for completion of drilling is \$500.
 - (c) The fee to modify operations at a well is \$1,500.
 - (d) The fee to sidetrack a well is \$500.
 - (e) The fee to plug and abandon a well is \$1,000.
 - (f) The annual renewal fee for operation and maintenance of a well is \$1,500 the first renewal year and \$500 for each subsequent year.
 - (g) The application fee for a permit to drill an information hole is to be determined by the department based on the estimated cost of review and approval, and the number and location of holes to be drilled. The fee may not exceed \$1,000 per information hole.
 - (h) The fee for approval of a seismic program shall be determined by the department based on the estimated cost of review and approval, but may not exceed \$1,000.
 - (i) The governing board of DOGAMI by rule may specify a schedule of fees for costs incurred by the department for activities related to field designation.
3. Require filing report of work performed: Yes. Rule 632-10-016.

Vertical Deviation

1. Regulation requirement: Rule 632-10-142.
 - (a) When is directional survey necessary? If intentionally deviated.
 - (b) Filing of survey required? Yes. Rule 632-10-142.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Rule 632-10-014 - General control.
 - (b) Production casing: Rule 632-10-014 - General control.
2. Minimum amount of cement required:
 - (a) Surface casing: Bottom to top. Rule 632-10-014.
 - (b) Production casing: Based on fluid zones. Rule 632-10-014.
 - (c) Setting time: 12 hours. Rule 632-10-014.
3. Tubing requirements:
 - (a) Oil wells: General. Rule 632-10-132. Bottom of tubing on flowing wells not higher than 100 feet above the

producing formation.

- (b) Gas Wells: General. Rule 632-10-132. Bottom of tubing on flowing wells not higher than 100 feet above the producing formation.

Completion

1. Completion report required: Yes. ORS 520.095(2) and Rule 632-10-016.
 - (a) Time limit: Within 20 days of completion or abandonment.
 - (b) Where submitted: To the Department.
2. Well logs required to be filed: Yes. ORS 520-095 (2) and Rule 632-10-016.
 - (a) Time limit: Within 20 days of completion or abandonment, or suspension.
 - (b) Where submitted: To the Department.
 - (c) Confidential time period: Yes, two years.
 - (d) Available for public use: Yes. ORS 520.095(2) and Rule 632-10-016.
 - (e) Log catalog available. Yes.
3. Multiple completion regulation: Yes. Rule 632-10-152.
 - (a) Approval obtained: Through the State Geologist.
4. Commingling in well bore: No. Rule 632-10-152.

Oil Production

1. Definition of an oil well: "Oil Well" shall mean any well not a gas well capable of producing oil or condensate in paying quantities. Rule 632-10-008.
2. Potential tests required: Yes, by order of Board. Rule 632-10-170.
 - (a) Time interval: Not specified.
 - (b) Witness required: Yes. Rule 632-10-170.
3. Statewide allowable: Implied. Rule 632-10-148.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
4. Maximum gas-oil ratio: Determined by Board. Rule 632-10-186.
 - (a) Provision for limiting gas-oil ratio: Yes. Maximum ratio set by Board for pool.

- (b) Exception to limiting gas-oil ratio: Yes, if excess is returned to the production formation.
- 5. Bottom-hole pressure test reports required: Yes, by order of Board. Rule 632-10-170.
 - (a) Periodical bottom-hole pressure surveys: Yes. Rule 632-10-170.
- 6. Commingling oil in common facilities: No. Rule 632-10-164.
- 7. Measurement involving meters: No.
- 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limit: Last day of each month succeeding the month in which the purchasing of taking occurs. Rule 632-10-166.

Gas Production

- 1. Definition of a gas well: Well producing natural gas (does not include oil or condensate). Rule 632-10-008.
- 2. Pressure base _____ psia @ _____ degrees F. Not specified.
- 3. Initial potential tests: Yes. Rules 632-10-174, 176, 178.
 - (a) Time interval: Time necessary to effect accurate determination.
 - (b) Witness required: Yes.
- 4. Statewide allowable: Implied. Rule 632-10-148.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
- 5. Bottom-hole pressure test reports required: Yes, by order of Board. Rule 632-10-170.
 - (a) Periodical bottom-hole pressure surveys. Yes. Rule 632-10-170.
- 6. Commingling of gas in common facilities: Yes, if ratable take can be maintained. Rule 632-10-182.
- 7. Measurement involving meters: Yes. Rule 632-10-182.
- 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limit: Last day of each month succeeding the month in which the purchasing or taking occurs.

Water Disposal

1. State agencies that control disposal of produced salt water: Department of Geology and Mineral Industries and Department of Environmental Quality would control waste water disposal. Rule 632-10-192.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. ORS 520.290.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 75%.
 - (b) Royalty interest: 75%.

ORS 520.290.

Taxation

Gross production tax = 6.0%
 Gas ad valorem tax = 0.0%
 Total gas tax burden = 6.0%

Oil production tax = 6.0%
 Oil ad valorem tax = 0.0%
 Total oil tax burden = 6.0%

1. Tax collecting agency: Department of Revenue, Revenue Building, 955 Center Street, N.E., Salem, OR 97310.
2. How tax is computed: Oregon has a gross production tax for oil and gas that is computed at 6%.
3. Exemptions or exceptions: There is an exemption on the first \$3,000 in gross sales value each calendar quarter from each well. Also, royalty or other interest owned by state, county, city, town or school district or other political subdivision is exempt from the tax.
4. Name of tax: Gross Production.
5. Statutory citation: Oregon Revised Statute Chapter 324.

Land Leasing Information

1. Leasing Method: Sealed bids or oral bid auction.
2. Notice Method: At least one public notice of each auction by publication in a newspaper of general circulation in the county in which the lands are located at least 30 days prior to the auction date.
3. Minimum bidding \$ (per acre): The minimum starting bid amount per acre will be set forth in the notice by the Director.
4. Qualification of the bidder: A citizen of the U.S. of legal age or partnership or a corporation registered with the State Corporation Division, or a domestic governmental body.
5. State Statutes: Oregon Admin. Rules
 - §141-010-0010
 - §141-010-0020
 - §141-070-0020
 - §141-070-0050
 - §141-070-0060
 - §141-070-0080

§141-070-0090
 §141-070-0100
 §141-071-0535 ~
 §141-071-0595

6. Maximum acres: 640 acres
7. Contact: Steve Purchase, Assistant Director, Field Operations
 Phone: (503) 378-3805, Extension 279
 775 Summer Street, N.E.
 Salem, OR 97310-1337

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Oregon Health Division, Radiation Protection Services, 800 N.E. Oregon St., Portland, OR 97232.
 Phone: (503) 731-4014.
2. Relevant Statute/Regulations: OAR 333-117-010 to -370.
3. Scope: Anyone who engages in extraction, mining, beneficiating, processing, use, transfer or disposal.
4. Licensing: Yes.
5. Cleaning Equipment: Yes.
6. Disposal of Waste: Yes.
7. Subsequent Use of Equipment: Yes.
8. Subsequent Use of Materials: Yes.
9. Release/Sale of NORM-Contaminated Land: Must meet decommissioning and decontamination criteria.
10. Projected Volume of stored NORM in the State:
11. Respondent: Ray Paris and Dan Wermiel

PENNSYLVANIA

Administration

(NOTE: Oil and gas in Pennsylvania is regulated under three separate acts. For brevity initials will be used in this summary. The Oil and Gas Act, Act of 12-19-84, P.L. 1140, No. 223 is termed OGA; the Coal and Gas Resource Coordination Act, Act of December 18, 1984, No. 214 is termed RCA; and the Oil and Gas Conservation Law, Act of July 25, 1961, P.L. 825, 58 P.S. §401 et seq. is termed OGCL.) Regulations promulgated under these statutes are found at Title 25 PA Code Chapters 78 & 79.

1. State agency: Department of Environmental Protection, Bureau of Oil and Gas Management, central office at P. O. Box 8765, Harrisburg, PA 17105-8765. Phone (717) 772-2199. Regional office: 400 Waterfront Drive, Pittsburgh, PA 15222-4745. Phone (412) 442-4015. Regional office: 230 Chestnut Street, Meadville, PA 16335. Phone (814) 332-6860.
2. Docketing procedure: OGA: Objections may be filed and conference held. The parties may appeal to the Environmental Hearing Board. Sections 202 and 501. RCA: Objections are filed with the Department, then submitted to a panel, which makes recommendations to the Department. Section 12. Decisions may be appealed to the Environmental Hearing Board. OGCL: Objections and comments may be filed with the Department or testified to at public meetings concerning spacing and integration applications.
 - (a) Emergency orders: Yes. Emergency action can be taken by the Department without a prior hearing. Actions are appealable to the Environmental Hearing Board. Section 503 OGA and Section 410 OGCL.
 - (b) Notice: OGA: Notice of intent to revoke or suspend a well permit or registration is given to the well operator. The well operator has 15 days to request a conference. Section 503. OGCL: Notice of spacing and integration orders must be provided in accordance with Sections 7, 8, and 10 of the Act. RCA: Notice is issued by the Department in regard to conflicting permit applications (Section 6), objections to drilling (Section 12), and by the well operator in regard to plugging (Section 13).

Bond

1. Compliance bond required: Section 215 of OGA requires a bond in the amount of \$2,500 per well or a blanket bond in the amount of \$25,000 for wells drilled on or after April 18, 1985.
2. Conditions of bond: Conditioned on the operator's faithful performance of the drilling, restoration, water supply replacement, and plugging requirements of the OGA.

Spacing

1. Spacing requirements: OGA: None. RCA: Gas wells in workable coal seams must be at least 1,000 feet from any other well. OGCL: An operator may apply for a spacing order pursuant to Section 7 of the Act. A conservation well must be at least 330 feet from the boundary of the tract or unit.
2. Exceptions: RCA: Yes.
 - (a) Basis: Minimum spacing may be as little as 900 feet where permit applicant and owner of workable coal seam consent.
 - (b) Approval: By the Department of Environmental Protection.
- 2.1 Exceptions: OGCL: Yes, if the well would not be likely to produce in paying quantities, if there are adverse surface conditions, or if coal operators have objected and a well is prohibited in a certain area. Section 7.
 - (a) Approval: By the Department of Environmental Protection.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes. OGCL, Section 8.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes. OGA, Section 201; RCA, Section 5; OGCL, Section 6.
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes, if it constitutes redrilling, alteration, deepening or drilling.
 - (d) Plugging and abandoning: OGA: Well operator or owner must notify Department and coal operator, lessee or owner of his intent to plug and abandon a well, pursuant to Section 210. RCA: Any person may apply for authorization to clean out, plug or replug a nonproducing well, Section 13.
2. Permit fee:
 - (a) Drilling: \$250 per oil well; \$350 per gas well; no fee to adopt an orphan well.
 - (b) Seismic drilling: None.
 - (c) Recompletion: If it constitutes redrilling, alteration, deepening or drilling, a permit application fee of \$150 is required.
 - (d) Plugging and abandoning: None under the RCA.
 - (e) Registration: \$15 per well, or \$250 for blanket registration of wells that are submitted simultaneously.
3. Require filing report of work performed:
 - (a) Annual production report.
 - (b) Records of drilling or altering a well within 30 days of cessation of drilling.
 - (c) Completion report within 30 days.
 - (d) If requested by the Department within 90 days of completion, operator must file electrical, radioactive, or other standard industry logs within 3 years if they have been run. Other geological data must be filed if requested by the Department within one year. Section 12, OGA.
 - (e) Well operator must submit certificate of plugging. OGA, Section 210; RCA, Section 13, and 25 Pa. Code §79.17, promulgated pursuant to the OGCL.

Vertical Deviation

1. Regulation requirement:
 - (a) When is directional survey necessary? OGA: Section 201 requires the well operator to designate the proposed angle and direction of the well, if the well is to be deviated substantially from a vertical course. This information must be stated on the plat submitted with the permit application. OGCL: A complete angular deviation and directional survey must be submitted upon completion of an intentionally deviated well. 25 Pa. Code §79.16.

- (b) Filing of survey required? OGA: Information on the angle and direction of well, as described above, is required to be filed with the permit application. OGCL: Yes.

Casing and Tubing

1. Minimum amount required:

- (a) Surface casing: Wells must have sufficient casing so as to prevent waste and the required minimum amount of surface casing to be set must be in accordance with Table 1 unless otherwise specified by the Department.

Table 1

<u>Proposed Total Depth (in feet)</u>	<u>Minimum Casing Required (in feet)</u>
3,800 to 5,000	400
5,001 to 5,500	500
5,501 to 6,000	600
6,001 to 6,500	700
6,501 to 7,000	800
7,001 to 8,000	1,000
8,001 to 9,000	1,200
9,001 to 10,000	1,400
Deeper than 10,000	1,800

Wells must be cased through fresh water bearing strata to prevent the migration of gas or fluids into sources of fresh groundwater and to prevent pollution or diminution of fresh groundwaters. Casing and cementing requirements defined by 25 Pa. Code §78.71-86, promulgated pursuant to the OGA and OGCL.

- (b) Through coal seams: Wells must be cased to prevent the migration of gas or fluids into a seam from which coal has been removed. Where the coal seam has not been removed, the well must be drilled to such a depth and size to permit the placing of casing in the well, so that all gas or fluids will be excluded from the coal seam. OGA, Section 207. Casing and cementing requirements defined by 25 Pa. Code § 78.71-86, promulgated pursuant to the OGA.
- (c) Production casing: OGCL: Wells must be cased to prevent the migration of all fluids from any formation covered by the Act to any other formation. 25 Pa. Code §79.12(c).

2. Minimum amount of cement required:

- (a) Surface casing: Casing and cementing standards defined by 25 Pa. Code § 78.71-86, promulgated pursuant to the OGA and OGCL.
- (b) Production casing: For conservation wells, the production casing must be cemented to fill the annular space to a point at least 500 feet above the casing shoe and at least 200 feet above the uppermost perforations.
- (c) Setting time: Cement must be set to a minimum compression strength of 350 psi and at least for 8 hours. 25 Pa. Code §78.85(b)

3. Tubing requirements:

- (a) Oil wells: No provision.
- (b) Gas wells: No provision.

Completion

1. Completion report required: Yes.
 - (a) Time limit: OGA: Well records must be filed within 30 days of cessation of drilling. A report containing additional information as required by regulation shall be filed within 30 days after completion.
 - (b) Where submitted: To the Department of Environmental Protection.
2. Well logs required to be filed: Yes.
 - (a) Time limit: Well records must be filed within 30 days of cessation of drilling. Within 90 days after completion or recompletion if requested by the Department, the well operator must submit a copy of the electrical, radioactive or other standard industry logs within 3 years if they have been run. If requested by the Department within one year, the well operator must file drill stem test charts; formation water analyses; porosity, permeability, or fluid saturation measurements; core analysis and lithologic log or sample description.
 - (b) Where submitted: To the Department of Environmental Protection.
 - (c) Confidential time period: None.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: See Department of Environmental Protection.
3. Multiple completion regulation: Not applicable.
 - (a) Approval obtained. Not applicable.
4. Commingling in well bore: Not applicable.
 - (a) Approval obtained: Not applicable.

Oil Production

1. Definition of an oil well: A bore hole drilled or being drilled for the purpose of or to be used for producing, extracting, or injecting hydrocarbons in liquid form at standard temperature of 60 degrees Fahrenheit and pressure 14.7 psia combined definition of well and oil.
2. Potential tests required: None.
 - (a) Time interval: Not applicable.
 - (b) Witness required: Not applicable.
3. Statewide allowable: No regulation making general allotments of production.
 - (a) Pool allowable: Not applicable.
 - (b) Well allowable: Not applicable.
 - (c) Exempt allowable: Not applicable.

4. Maximum gas-oil ratio: No regulation.
 - (a) Provision for limiting gas-oil ratio: No.
 - (b) Exception to limiting gas-oil ratio: No.
5. Bottom-hole pressure test reports required: Provision to include in well record, if taken.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: No.
7. Measurement involving meters: No.
8. Production reports: OGA, Section 212.
 - (a) By lease: No.
 - (b) By well: Annual production report is required on an individual well basis.
 - (c) Time limit: Annual.

Gas Production

1. Definition of a gas well: A bore hole drilled or being drilled for the purpose of or to be used for producing, extracting, or injecting any fluid, either combustible or noncombustible, which is produced in a natural state from the earth and which maintains a gaseous or rarified state at standard temperature of 60 degrees Fahrenheit and pressure 14.7 psia, any manufactured gas, any by-product gas, or any mixture of gases. Combined definition of well and gas.
2. Pressure base 14.7 psia @ 60 degrees F.
3. Initial potential tests: None.
 - (a) Time interval: Not applicable.
 - (b) Witness required: Not applicable.
4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Provision to include in well record, if taken.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: No.
7. Measurement involving meters: No.
8. Production reports: OGA, Section 212.

- (a) By lease: No.
- (b) By well: Annual production report is required on an individual well basis.
- (c) Time limit: Annual.

Water Disposal

1. State agencies that control disposal of produced salt water: Department of Environmental Protection.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes, upon application for an integration order by an operator having an interest in the spacing unit.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: No provision.
 - (b) Royalty interest: No provision.

Taxation

There is no state tax levied on oil and gas production in Pennsylvania.

Land Leasing Information

1. Leasing Method: Department of Conservation and Natural Resources receives nominations for lease sale on an open basis. Once critical mass is achieved from the continuous nominations process a competitive lease sale may be held, typically utilizing sealed bids. Leases are usually offered and awarded on highest bonus bid, but there are also royalty type sales called for from time to time.
2. Notice Method: Advertisement and mailing to all interested parties as well as to the parties on their prospective bidder list for notification.
3. Minimum bid amount per acre \$ (10.00 per acre): Annual Rentals at \$5.00 per acre.
4. Qualification of the bidder: Any person - corporation must be registered to do business within Pennsylvania and be in good standing with the Department of State's Corporation Bureau to participate in the bid process.
5. State Statutes: Act # 1995-18
6. Maximum acres: Variable, but average size of lease tracts has historically been around 2,000 acres per lease tract.
7. Contact: Teddy W. Borawski, Jr.
Phone: (717) 772-0269

NOTE: Lease sales held on a variable schedule depending on the number of nominations and the general industry interest level. On average, lease sales have occurred approximately once a year, but less frequently in the last five years.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environmental Protection, Bureau of Oil and Gas Management, P.O. Box 8765, Harrisburg, PA 17105-8765. Phone: (717) 772-2199.
2. Relevant Statute/Regulations: None existing or proposed. Surveys have shown NORM is not an issue with oil and gas production in Pennsylvania.

3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Contact person : Ronald Gilius
12. Regulating Agency: Department of Environmental Protection, Bureau of Radiation Protection, P.O. Box 8469, Harrisburg, PA 17105-8469. Phone: (717) 787-3720.
13. Relevant Statute/Regulations: Pennsylvania has no NORM regulations.
14. Scope: NORM problems are addressed using existing regulations and EPA/NRC standards on a case-by-case basis.
15. Licensing:
16. Cleaning Equipment:
17. Disposal of Waste:
18. Subsequent Use of Equipment:
19. Subsequent Use of Materials:
20. Release/Sale of NORM-Contaminated Land:
21. Projected Volume of stored NORM in the State:
22. Contact person: Louis Urciuolo

SOUTH DAKOTA

Administration

1. State agency: Fred V. Steece, Oil and Gas Supervisor, Department of Environment and Natural Resources, 2050 W. Main, Ste #1, Rapid City, SD 57702. Phone (605) 394-2229, Fax (605) 394-5317.
2. Docketing procedure: Make application to above address. Department will review for completeness and will set hearing date if required according to type of application as follows: Hearing required: spacing, forced pooling, unitization; Administrative Approval: exception location, underground injection, commingling, directional drilling, horizontal drilling. (Note: if objection is filed within 20 days of the last publication date, a hearing will be scheduled.) Hearings held by S.D. Board of Minerals and Environment.
 - (a) Emergency orders: Law allows issuance of emergency orders by the Board without notice and hearing, that are effective for 15 days.
 - (b) Notice: Notice of public hearing must be published at least 20 days in advance of hearing. Supervisor will give notice.

Bond

1. Compliance bond required: A "Plugging and Performance Bond" (Form 3) and a "Surface Restoration Bond" (Form 10) are required. "Surface Restoration Bond" required when surface and mineral estates are severed.
2. Conditions of bond: Conditions are to plug each abandoned well, restore premises, and to fulfill requirements set out in paragraphs 45-9-5 to 45-9-18, South Dakota Codified Law (SDCL).
 - (a) Amount per well: \$5,000 for plugging; \$2,000 for surface restoration.
 - (b) Amount of blanket bond: \$20,000 for plugging; \$10,000 for surface restoration.

Spacing

1. Spacing requirements: Yes. Rule 74:10:03:08, 74:10:03:09, and 74:10:03:10.
 - (a) Density: Oil, 40 acres; gas, 640 acres.
 - (b) Lineal: Oil well - 500 feet from quarter-quarter boundary and 1,000 feet between wells. Gas well - 500 feet from section line and 3,750 feet between wells.
2. Exceptions: Yes. Address request to Supervisor at the above address.
 - (a) Basis: Topographic reasons, well at prescribed location would not produce economically or other good cause shown. (Rule 74:10:03:11).
 - (b) Approval: Administratively by the Department. Applicant must provide evidence of "good cause", must provide affidavit of service by certified mail to "any person whose property may be affected by the hearing". The Department publishes a Notice of Recommendation on the matter in the official county newspaper and the official state newspaper, and others. Upon 20 days notice if no objections are filed, the application may be approved. If objections are made, a hearing is required.

Pooling

1. Authority to establish voluntary: Yes. SDCL 45-9-30 to 45-9-36.
2. Authority to establish compulsory: Yes. SDCL 45-9-31, et seq. Board has the authority to assess a penalty for risk on

the non-participating owner in a spacing unit; (Rules 74:10:18:01 to 74:10:18:06. SDCL 45-9-37 to 49-9-52).

Drilling Permit

1. Require permits for:

- (a) Drilling a producing or service well: Yes. Permit is good for one year. The minimum requirements for obtaining a permit are the filing of the following: organization report, application for permit to drill, certified plat map, \$100 permit fee, plugging and performance bond, surface restoration bond, certificate of negotiation with surface owner or lessee, bonding company information sheet. Application for pit liner variance (Rule 74:10:03:13) may be made to the Department. The Department may attach conditions to both the application for permit to drill and to the application for pit liner variance.

Applications for horizontal wells must meet the minimum requirements for obtaining a permit to drill in addition to the following information: size, weight, and amount of all casing strings; top of cement behind each casing string; mud program; coordinates of the casing shoe; coordinates of the terminus; depth of kick-off point; azimuth of the horizontal segment; down-hole survey frequency; name and address of surveying contractor; and location of cementing tool. (Rule 74:10:03:01.01).

- (b) Seismic drilling: Yes. Contact Surface Mining Program, Department of Environment and Natural Resources, Joe Foss Bldg., 523 E. Capitol Ave., Pierre, SD 57501. Phone: (605) 773-4201.
- (c) Recompletion: Yes, for re-entry. Rule 74:10:03:01. Other work to be submitted on a Sundry Notice.
- (d) Plugging and abandoning: No, but Supervisor must be contacted for approval of plugging program before plugging begins. A well may be saved for conversion to a water well upon notification of oil and gas supervisor.

2. Permit fee:

- (a) Drilling: \$100 per well.
- (b) Seismic drilling: No. Contact Surface Mining Program, Department of Environment and Natural Resources, Joe Foss Bldg., 523 E. Capitol Ave., Pierre, SD 57501. Phone (605) 773-4201.
- (c) Recompletion: \$100 per well; require permit to drill a re-entry (see above).
- (d) Plugging and abandoning: No fee; require plugging report (Form 7) within 30 days.

3. Require filing report of work performed: Yes. Completion report (Form 4); Plugging report (Form 7), Sundry Notice (Form 6). Require two copies each of the following: geologic report, drill-stem test reports, all geophysical logs, all downhole surveys, core report and analyses, water analyses, and 10-foot sample cuttings.

4. Injection wells: Casing strings must be designed or retro-fitted to prevent pollution of fresh water resources by disposed fluid. Tubing strings are required in injection wells. Mechanical integrity must be shown initially and at least every five years. Continuous mechanical monitoring is allowed under certain circumstances. Wells are inspected periodically by supervisor's office.

Vertical Deviation

1. Regulation requirement:

- (a) When is directional survey necessary? Required for all directional and horizontal wells; secretary may require deviation test if necessary; special permit required from secretary utilizing Notice of Recommendation for directional drilling. (Rule 74:10:03:20 and 74:10:03:21). Minimum distances must be maintained from spacing unit boundaries and between wells, for all horizontal and directional holes.

- (b) Filing of survey required? Yes, required on all directional and horizontal holes.

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Fields: Yes, see field rules for specific fields. Statewide: Yes, must be set below all shallow fresh water sands; not less than 100 feet.
 - (b) Production casing: Yes. All freshwater zones are to be sealed or separated by casing and cement. Cement bond log is required on all completed wells. See field rules for specific fields.
2. Minimum amount of cement required:
 - (a) Surface casing:

Fields: Yes. Require cementing by pump and plug method and cement returns to the surface.

Statewide: Yes. Require cementing by pump and plug method and cement returns to the surface.
 - (b) Production casing:

Fields: Yes. See rules in specific field orders.

Statewide: Cement to seal or separate all fresh water zones not covered by the surface casing.
 - (c) Setting time: Yes. Surface casing 12 hours, production casing 24 hours.
3. Tubing requirements:
 - (a) Oil wells: Yes. Require wells to be equipped with tubing.
 - (b) Gas wells: Yes. Require wells to be equipped with tubing.
4. Injection wells: Casing strings must be designed or retro-fitted to prevent pollution of fresh water resources by disposed fluid. Tubing strings are required in injection wells. Injection volumes both for salt water disposal and for enhanced recovery, whether air, gas or water, or other fluid, must be reported monthly on Form 5A by the 25th day of the succeeding month. Pressure fall-off tests are required on all air injection wells initially and at intervals of at least every five years. Annular pressure mechanical integrity tests are required on all water injection wells initially and at intervals of at least every five years. Continuous mechanical monitoring is allowed under certain circumstances.

Completion

1. Completion report required: Yes. Well Completion or Recompletion Report and Log (Form 4).
 - (a) Time limit: 30 days.
 - (b) Where submitted: Oil and Gas Supervisor, Department of Environment and Natural Resources, 2050 W. Main, Ste. #1, Rapid City, SD 57702.
2. Well logs required to be filed: Yes. All electrical and geophysical logs, down hole surveys, geologic reports, water analyses, DST reports, core analyses, and any other geological or engineering data.
 - (a) Time Limit: 30 days.
 - (b) Where submitted: Oil and Gas Supervisor, above address.
 - (c) Confidential time period: Yes. Six months, if requested in writing, may be extended if requested in writing.

- (d) Available for public use: Yes. Public information after confidential period is over.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes. Administratively by the Department utilizing Notice of Recommendation (Rule 74:10:03:20 and 74:10:03:21).
 - (a) Approval obtained: Applicant must provide affidavit of service by certified mail to "any person whose property may be affected by the hearing". The Department publishes a Notice of Recommendation on the matter in required newspapers. Upon 20 days notice, if no material objections are filed, the application is approved. If objections are made a hearing is required.
 4. Commingling in well bore: May be granted administratively by the Department. Applicant must provide affidavit of service by certified mail to "any person whose property may be affected by the hearing". The Department publishes a Notice of Recommendation on the matter in required newspapers. Upon 20 days notice, if no material objections are filed, the application is approved. If objections are made a hearing is required.

Oil Production

1. Definition of an oil well: "A well capable of producing oil". Rule 74:10:02:01(18).
2. Potential tests required: Yes. To be reported on completions or recompletion report and log (Form 4). (Rule 74:10:05:02).
 - (a) Time interval: 30 days.
 - (b) Witness required: May be at discretion of Oil and Gas Supervisor.
3. Statewide allowable: No. The Board has authority to prorate and allocate, but has never enforced proration.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
4. Maximum gas-oil ratio: Yes. The Board may require "that wells not be operated with inefficient gas-oil or water-oil ratios". In addition, the Board may fix their ratios and limit production from wells with inefficient gas-oil or water-oil ratios. SDCL 45-9-10.
 - (a) Provision for limiting gas-oil ratio: Yes. SDCL 45-9-10.
 - (b) Exception to limiting gas-oil ratio: Yes. Can be granted administratively if no objections are received by the Department, by utilizing the Notice of Recommendation procedure. (Rule 74:10:03:20 and 74:10:03:21).
5. Bottom-hole pressure test reports required: BHP required on new pool within 30 days. Rule 74:10:05:02.
 - (a) Periodic bottom-hole pressure surveys: May be required in field rules.
6. Commingling oil in common facilities: Yes. Production from different pools may be commingled provided the amount of production from each pool is determined by a method approved by the Department. (Rule 74:10:05:03). Approval may be granted administratively utilizing the Notice of Recommendation procedures. (Rule 74:10:03:20 and 74:10:03:21).
7. Measurement involving meters: Use of calibrated meter measurements or tank measurements are allowed.

8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Operator must report oil, gas and water produced on Form 5.
 - (b) Time limit: 25th day of following month. (Rule 74:10:05:12).
9. Water flood and enhanced recovery:
 - (a) Make application to oil and gas supervisor for all underground injection operations.
 - (b) Unit operations may be approved after notice and hearing by the Board of Minerals and Environment.
 - (c) Report volume of fluid injected and pressure by 25th of following month on Form 5A.
10. Change of operator:
 - (a) File Notice of Change of Operator (Form 13, pg. 1&2) to be executed by both the transferring party and the receiving party. File with oil and gas supervisor.
 - (b) Bond coverage must be in force on the receiving party and filed with the oil and gas supervisor before transferring party's bond can be considered for release.

Gas Production

1. Definition of a gas well: "A well capable of producing gas from a common source of gas supply as determined by the Board, excluding gas that cannot be sold for use". (Rule 74:10:02:01(11)).
2. Pressure base 14.65 psia @ 60 degrees F.
3. Initial potential tests: Required to report on Form 4.
 - (a) Time interval: 30 days.
 - (b) Witness required: At discretion of Oil and Gas Supervisor.
4. Statewide allowable: None.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
5. Bottom-hole pressure test reports required: Yes, new pool.
 - (a) Periodical bottom-hole pressure surveys: May be required in field rules. Shut-in pressure required annually.
6. Commingling of gas in common facilities: No.
7. Measurement involving meters: Gas must be metered; gas produced must be reported by the operator whether or not delivered to a gas transportation facility. The operator is required to report all produced gas to the Oil and Gas Supervisor. (Rule 74:10:06:03).

8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes. Operator must report all gas produced on Form 5.
 - (c) Time limit: 25th of following month. (Rule 74:10:05:12).

Water Disposal

1. State agencies that control disposal of produced salt water: Board of Minerals and Environment, (Contact Oil and Gas Supervisor's Office). (Rule 74:10:05:13, 74:10:05:15, and 74:10:09:01 thru 74:10:09:14). Report volume of fluid injected by the 25th of the following month on Form 5A.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. "The Board upon its own motion may, and upon the application of any interested person shall, hold a hearing to consider the need for the operation as a unit of one or more pools or parts thereof in a field". (SDCL 45-9-37). Risk compensation is allowed up to 200 percent of the non-participating owners share of the reasonable actual unit expenses, exclusive of one-eighth royalty, to the recovered our of production from the unit.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 60%.
 - (b) Royalty interest: 60%.

Taxation

Gas severance tax = 4.5% of value
 Gas conservation tax = 2.4 mils or .24%
 Gas ad valorem tax = variable by county
 Total gas tax burden = 4.74% of value

Oil severance tax = 4.5% of value
 Oil conservation tax = 2.4 mils or .24%
 Oil ad valorem tax = variable by county
 Total oil tax burden = 4.74% of value

1. Tax collecting agency: Department of Revenue, Anderson Building, 445 E. Capitol Ave., Pierre, SD 57501-3185.
2. How tax is computed: South Dakota has a severance tax that is 4.5% of the value of oil and gas. There is also a conservation tax of 2.4 mils on the value of oil and gas. Counties also make tax assessments. The County Assessor determines real and personal property taxes.
3. Exemptions or exceptions: None
4. Name of tax: Severance; Conservation
5. Statutory citation: SDCL 10-39B

Land Leasing Information

1. Leasing Method: Public auction.

2. Notice Method: The notice shall be published once each week for at least 2 consecutive weeks in the official newspapers of the county, where the land is located.
3. Minimum bidding \$ (per acre): No less than \$2.00 per acre.
4. Qualification of the bidder:
5. State Statutes: SDCL 5-7
6. Maximum acres: 640 acres per tract.
7. Contact: Oil and Gas Administrator, Dept. of School and Public Lands, State Capitol, 500 E. Capitol, Pierre, SD 57501. Phone: (605) 773-3303, Fax: (605) 773-5520.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environment and Natural Resources, 2050 W. Main, Ste. 1, Rapid City, SD 57702. Phone: (605) 394-2229.
2. Relevant Statute/Regulations: South Dakota has no oilfield rules addressing NORM at present. There are no NORM rules being proposed at present.
3. Scope: Not applicable.
4. Licensing: Not applicable.
5. Cleaning Equipment: Not applicable.
6. Disposal of Waste: Not applicable.
7. Subsequent Use of Equipment: Not applicable.
8. Subsequent Use of Materials: Not applicable.
9. Release/Sale of NORM-Contaminated Land: Not applicable.
10. Projected Volume of stored NORM in the State: Not applicable.
11. Respondent: Fred V. Steece

TENNESSEE

Administration

1. State agency: State Oil and Gas Board, 13th Floor, L & C Tower, 401 Church St., Nashville, TN 37243-0445. Phone (615) 532-0166, Fax (615) 532-1517, E-mail michael.k.burton@state.tn.us.
2. Docketing procedure: Upon request of a concerned party or as called by the Oil and Gas Board. TCA 60-1-204; 1040-6-1-.01 of Rules and Regulations.
 - (a) Emergency orders: Can be issued by order of the Oil and Gas Board. TCA 60-1-204(c).
 - (b) Notice: Ten (10) days notice. By the State Oil and Gas Board Supervisor.

Bond

1. Compliance bond required: Yes, may be in the form of cash, a certified check, corporate surety, irrevocable standby letter of credit or joint custody certificate of deposit. 1040-2-1 of Rules and Regulations.
2. Conditions of bond: Plugging - Compliance with laws and Rules and Regulations - filing with the Supervisor all records required by the Board - plugging of well (or wells) in accordance with the law and Rules and Regulations. Reclamation - Separate reclamation bond for restoration of well site and access roads, with minimum established ground cover of at least 90 percent after plantings have survived two growing seasons. 1040-2-1 of Rules and Regulations.
 - (a) Amount per well: Plugging - \$2,000, \$1,000 for domestic gas wells; Reclamation - \$1,500 for new wells, \$1,000 for a change of operator for wells on which initial reclamation has been accomplished.
 - (b) Amount of blanket bond: Plugging - \$10,000, up to a maximum of 10 wells per bond; Reclamation - none, except that letters of credit or joint custody certificates of deposit may be submitted in appropriate amounts to cover multiple wells.

Spacing

1. Spacing requirements: Yes. 1040-2-4 of Rules and Regulations.
 - (a) Density: Oil wells - 0-1,000 feet, 10 acres; 1,001-2,000 feet or to the base of the Devonian Chattanooga Shale, whichever is deeper, 20 acres; more than 2,000 feet or below the base of the Devonian Chattanooga Shale, whichever is deeper, 40 acres. No density requirement for horizontal wells.

Gas Wells - 0-1,000 feet, 10 acres; 1,001-2,000 feet or to the base of the Devonian Chattanooga Shale, whichever is deeper; 20 acres; more than 2,000 feet deep or below the base of the Devonian Chattanooga Shale, whichever is deeper - 5,000 feet or to the top of the Cambrian Conasauga Group, whichever is deeper, 40 acres; more than 5,000 feet deep or below the top of the Cambrian Conasauga Group, whichever is deeper, 160 acres. No density requirement for horizontal wells.
 - (b) Lineal: Oil wells - 330 feet or more from any property (lease) or unit line, and 660 feet or more from any other well completed in, drilling to, or for which a permit shall have been granted to drill to the same pool. No specific well-to-well distance requirement for horizontal wells.

Gas wells - 0-5,000 feet or to the top of the Cambrian Conasauga Group, whichever is deeper, 330 feet or more from any property (lease) or unit line, and 660 feet or more from any other well completed in, drilling to, or for which a permit shall have been granted to drill to the same pool; more than 5,000 feet deep or below the top of the Cambrian Conasauga Group, whichever is deeper, 660 feet or more from any property (lease) or unit line, and 1,320 feet or more from any other well completed in, drilling to, or which a permit shall have been granted to drill to the same pool. No specific well-to-well distance requirement for horizontal wells.

2. Exceptions: Yes.

- (a) Basis: For valid geological or topographic reasons.
- (b) Approval: Administratively by Supervisor, 1040-2-4-.01(k), or by Oil and Gas Board after public hearing. 1040-2-4-.01(k6).

Existing wells may be deepened and produced for oil or gas from whatever zone(s) production may be obtained on the existing permitted unit size.

Spacing of oil and gas wells - Referendum TCA 60-1-106. Oil or gas wells in Overton County: 0-2, 500 feet, 200 feet or more from any property line, and 400 feet or more from any other well completed in, drilling to, or for which a permit shall have been granted to drill to the same pool. Oil and gas wells in Clay and Pickett Counties: 200 feet or more from any property line, and 400 feet or more from any other well completed in, drilling to, or for which a permit shall have been granted to drill to the same pool.

Pooling

- 1. Authority to establish voluntary: Yes. TCA 60-1-202; 1040-2-2-.02(8) of Rules and Regulations.
- 2. Authority to establish compulsory: Yes. TCA 60-1-202(4)(M).

Drilling Permit

- 1. Require permits for:
 - (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: No.
 - (c) Recompletion: No.
 - (d) Plugging and abandoning: No.
- 2. Permit fee:
 - (a) Drilling: \$150.
 - (b) Seismic drilling: None. 1040-2-.02.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
 - (e) Change of operator: \$25.
 - (f) Amendment: \$25.

- 3. Require filing report of work performed: Yes. 1040-2-10.

Vertical Deviation

- 1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? When well bore deviates laterally greater than 5 degrees from vertical. 1040-2-8-.01(a).

- (b) Filing of survey required? Yes. 1040-2-10-.01(a).

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Yes, not less than 50 feet below all fresh water strata encountered in the well. 1040-2-7-.02.
 - (b) Production casing: No.
2. Minimum amount of cement required:
 - (a) Surface casing: Yes, circulate to fill annular space to the surface. 1040-2-7-.02.
 - (b) Production casing: No.
 - (c) Setting time: No.
3. Tubing requirements: 1040-3-2-.01.
 - (a) Oil wells: Yes, if flowing, unless otherwise allowed by the supervisor upon application.
 - (b) Gas wells: Yes.

Completion

1. Completion report required: Yes. 1040-2-10-.02(b).
 - (a) Time limit: Within 10 days after completion. 1040-2-10-.02(f).
 - (b) Where submitted: Supervisor, State Oil and Gas Board Office. 1040-2-10-.01 of Rules and Regulations.
2. Well logs required to be filed: Yes, if run. 1040-2-10-.02(a).
 - (a) Time limit: Within 30 days from date of drilling total depth. 1040-2-10-.01.
 - (b) Where submitted: To Supervisor, State Oil and Gas Board Office.
 - (c) Confidential time period: Yes, if requested. Six months from date of drilling to total depth upon written request of permittee. 1040-2-10-.05.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes.
3. Multiple completion regulation: Yes. 1040-3-1-.07.
 - (a) Approval obtained: By application for multiple completion to Supervisor. 1040-3-1-.07(1).
4. Commingling in well bore: Yes.
 - (a) Approval obtained: By order of Oil and Gas Board after public hearing. 1040-6-1-.01.

Oil Production

1. Definition of an oil well: Not defined in Rules and Regulations. An oil well with a gas/oil ratio in excess of 2,000

cubic feet of gas per barrel of oil (2,000:1) shall be considered a high gas/oil ratio well and maybe limited by the Supervisor in the amount of gas permissible to produce.

2. Potential tests required: Yes. 1040-3-1-.04(1) of Rules and Regulations.
 - (a) Time interval: When requested by the Supervisor.
 - (b) Witness required: Yes.
3. Statewide allowable: No.
 - (a) Pool allowable: Yes, by fieldwide rules.
 - (b) Well allowable: Yes. 1040-3-1-.04(1)(d).
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: Yes. 2,000:1. 1040-4-7-.01.
 - (a) Provision for limiting gas-oil ratio: Yes. High GOR wells may be limited to amount of gas permissible to produce by the Supervisor.
 - (b) Exception to limiting gas-oil ratio: Yes. Not specifically stated in Rules and Regulations.
5. Bottom-hole pressure test reports required: Yes, upon request by Supervisor. 1040-3-1-.07.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: Yes. (1) Submission of diagram of installation; (2) Producer certifies accurate measurement and method will not create inequities; (3) List of all affected parties. 1040-4-5-.01.
7. Measurement involving meters: No.
8. Production reports:
 - (a) By lease: Yes. 1040-4-3-.05.
 - (b) By well: No.
 - (c) Time limit: 25th day of succeeding month of production.

Gas Production

1. Definition of a gas well: Not defined in Rules and Regulations.
2. Pressure base 14.73 psia @ 60 degrees F. 1040-.1-1-.01.
3. Initial potential tests: Yes. 1040-3-1-.04(1)
 - (a) Time interval: 15 days after completion.
 - (b) Witness required: Yes.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes, by fieldwide rules.

- (b) Well allowable: Yes, by fieldwide rules.
- (c) Exempt allowable: No.
- 5. Bottom-hole pressure test reports required: Yes, upon request of Supervisor.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: Yes. Same requirements as for oil production. 1040-4-5-.01.
- 7. Measurement involving meters: No, except for testing.
- 8. Production reports: 1040-4-3-.11.
 - (a) By lease: Yes.
 - (b) By well: No.
 - (c) Time limit: 25th day of succeeding month.

Water Disposal

1. State agencies that control disposal of produced salt water: State Oil and Gas Board. 1040-4-1-.11. Tennessee Department of Environment and Conservation, Division of Ground Water Protection. 1200-4-6.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes. TCA 60-1-202(4)(M)&(N).
2. Minimum percentage of voluntary agreement before approval of compulsory unitization: Pool producers owning more than 50 percent of the pool acreage.
 - (a) Working interest: No.
 - (b) Royalty interest: No.

Taxation

Gas severance tax = 3.0% of the sale price
 Gas ad valorem tax = 0.0%
 Total gas tax burden = 3.0% of the sale price

Oil severance tax = 3.0% of the sale price
 Oil ad valorem tax = 0.0%
 Total oil tax burden = 3.0% of the sale price

1. Tax collecting agency: Tennessee Department of Revenue, Petroleum Tax Division, 702 Andrew Jackson State Office Building, Nashville, TN 37242.
2. How tax is computed: Oil and gas severance tax is computed as 3% of the sale price.
3. Exemptions or exceptions: Free gas used by the property owner or tenant under the terms of the lease is exempt unless it is in lieu of cash payment. Gas that has been injected into the ground for underground storage and thereafter withdrawn is also exempt.
4. Name of tax: Severance.
5. Statutory citation: Tennessee Code Annotated 60-1-301.

Land Leasing Information

No Regulations at this time.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environment and Conservation; Division of Radiological Health, 401 Church St., 3rd Fl., L & C Annex, Nashville, TN 37243-1532.
2. Relevant Statute/Regulations: State Regulations for Protection Against Radiation, 1200-2-4, 1200-2-5, 1200-2-10.
3. Scope: The state of Tennessee does not distinguish between NORM and any other radioactive material (NARM, byproduct, tanuranic, special nuclear material). All radioactive material is subject to the regulations of the state of Tennessee.
4. Licensing: All radioactive material including NORM is subject to the licensing of the state of Tennessee unless excluded on a case-by-case basis. This includes possession, storage, use, transfer, receive, own or the acquisition of any radioactive material unless otherwise exempted (NRC, Agreement State Exemptions).
5. Cleaning Equipment: This would require a specific license issued by the state of Tennessee for the authorization of a particular process.
6. Disposal of Waste: Waste must be disposed of as radioactive unless otherwise specifically authorized by the state of Tennessee (case-by-case).
7. Subsequent Use of Equipment: Equipment can be "free-released" if it meets the requirements of 1.86, NRC Regulatory Guide.
8. Subsequent Use of Materials: Materials must be specifically licensed for use as any other radioactive material unless specifically authorized by the state of Tennessee (case-by-case).
9. Release/Sale of NORM-Contaminated Land: Not encountered. Property would have to be decontaminated to levels at or very near 'true background.' Land could possibly be sold with institutional controls and restrictions if it was not completely "clean." (case-by-case).
10. Projected Volume of stored NORM in the State: Unknown, not characterized in this fashion.
11. Respondent: Michael Page.

TEXAS

Administration

1. State agency: Railroad Commission of Texas, Oil and Gas Division, 1701 N. Congress, Austin, TX 78701. Mailing address: P.O. Box 12967, Austin, TX 78711-2967. Phone (512) 463-6838.
2. Docketing procedure: Simple informal written request setting out requested action results in docketing of a public hearing. Minimum 10 days notice of hearing required by law. Various applications may be considered and approved administratively without hearing after notice and opportunity for hearing.

Compliance

1. An organizational report or any application for a permit is not accepted from, and P-4 certificate of compliance is not issued to, an organization
 - (a) that has had a violation relating to safety or the prevention or control of pollution for which a final order has been entered and all appeals exhausted; and, (1) the conditions that constituted the violation have not been corrected or (2) the assessed penalties and/or fines have not been paid, or
 - (b) that has an officer who served as an officer of an organization as described in (a) at the time of violation within seven years preceding the date on which the report, application or certificate is filed.
2. A permit, certificate of compliance, or P-5 Organization Report may be revoked, after notice and opportunity for hearing, for an organization as described in No. 1, above.

P-5 Financial Assurance

1. Financial assurance required: An annual financial assurance will be required for each organization filing an initial or renewal Form P-5 Organization Report who is engaged in activities regulated by the Commission other than those on the following list: (A) local distribution company; (B) gas marketer; (C) Crude Oil Nominator; (D) first purchaser; (E) well servicing company; (F) survey company; (G) salt water hauler; (H) gas nominator; (I) gas purchaser; or (J) plugger. For organization required to file financial assurance, the following options are available:
 - (a) Individual Performance Bond, Letter of Credit, or Cash Deposit. For use by organizations that operate wells only. The value of the bond/letter/deposit is determined by multiplying \$2/foot by the total aggregate depth of all wells on the schedule for the operator. This includes active, inactive, injection or disposal, 14(b) (2) extension, hydrocarbon storage, etc.
 - (b) Blanket Performance Bond, Letter of Credit, or Cash Deposit. This option can be used by any organization (and must be used by organizations with activities other than the operation of wells for which financial assurance is required). The value of the bond/letter/deposit is set according to a schedule based on the number of wells operated (which includes all wells):

\$25,000	-	an operator with 1 to 10 wells or an operator performing regulated activities other than the operation of wells (e.g., reclamation plants, gas processing plants, pipelines, gatherers, etc.)
\$50,000	-	an operator with 11 to 99 wells
\$250,000	-	an operator with 100 or more wells

Financial Assurance that is required due to the operation of wells may be satisfied by the filing of an acceptable well-specific insurance policy that provides for the plugging of a particular wellbore in an amount at least equal to that required under option (a) above. If such a policy is filed for a wellbore, then that wellbore is disregarded when calculating an operator's organizational financial assurance requirement.

2. For operators of wells located off-land (i.e., in bay or inland waters or offshore), the financial assurance required to be posted by an operator is increased (in addition to that required under #1 above) as follows:
 - (a) “Entry Level Bay & Offshore Bonding”: an amount equal to the presumed plugging cost for plugging a single non-land well. By rule, the presumed plugging cost for an offshore well is \$100,000; for wells located in the bay or inland waterways, \$60,000. The amount required to be posted may be reduced if the operator has security posted with other local jurisdictions covering these wells that may be collected by the Commission.
 - (b) “Non-Producing Bay & Offshore Well Bonding”: for each non-land well that is not productive of hydrocarbons (including inactive and service-type wells), the financial assurance requirement is increased by the presumed plugging cost of that well. The amount required to be posted under this requirement is reduced by the amount required to be posted under “Entry Level Bay & Offshore Bonding” above, and may be further reduced based on the ratio of non-producing to producing bay & offshore wells and on an evaluation of the net worth of the company.

An insurance policy as described in 1(a) above may be filed for a bay or offshore wellbore to exclude it from financial assurance calculations provided that it provides coverage in an amount at least equal to the presumed plugging cost of that wellbore as given in 2

Spacing

1. Spacing requirements: Yes. (Rule 37) Statewide 467'-1200' - spacing 40 acres for oil or gas wells.
 - (a) Density: Statewide 40 acres; Field rules adopted after hearing may specify different density.
 - (b) Spacing: Statewide 467'-1200'; Field rules adopted after hearing may specify different spacing.
 - (c) Districts 7B, 9 all depths and 7C McCulloch to a depth of 2000' County spacing and density according to depth.
2. Exceptions: Yes.
 - (a) Basis: Prevention of waste or confiscation.
 - (b) Approval: By application. Approved without hearing if no protest received after notice or if waivers submitted.
 - (c) Fee: \$200.00 (Eff. 12-20-01)

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Only where voluntary efforts fail and in accordance with strict statutory requirements, after notice and hearing.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes, for an oil, gas, geothermal, fluid injection, fluid source, exploratory or service well.
 - (b) Seismic drilling: Yes, if well penetrates base of usable water.
 - (c) Cathodic protection well: Yes, if well penetrates the base of usable quality water.
 - (d) Recompletion: Yes, if change in field and/or reservoir is made.
 - (e) Reentry of a plugged wellbore: Yes.

- (f) Materially amended: Yes, change after approval of permit.
2. Drilling Permit Applications and fee. (Rule 5) When filing is required, the following documents must be submitted: Form W-1, plat, along with a current Organization Report (ACTIVE) on file with the Commission, and correct filing fee.
- (a) Drilling: Fee is determined by total depth of wellbore except in case of a plugback. Drilling Permit Fee Based on Depth: 0'-2000' is \$200, 2001'-4000' is \$225, 4001-9000' is \$250, > 9000' is \$300. Additional fee of \$150.00 (eff. 9-1-01) to expedite, in person or through the mail or requested by telephone,. An additional \$200.00 (eff. 12-20-01) fee if exception to the fields spacing or density rule is sought.
- (b) Seismic drilling: Minimum \$200.00 (eff. 9-1-01) fee if permit is required. Refer to (a).
- (c) Recompletion: Minimum \$200.00 (eff. 9-1-01) fee when change in field and/or reservoir is requested. Refer to (a).
- (d) Reentry of a plugged wellbore: Minimum of \$200.00 (eff. 9-1-01) fee. Refer to (a).
- (e) Materially amended: Minimum \$200.00 (eff. 9-1-01) fee plus amended application. Refer to (a).
3. Require filing report of work performed: Yes, completion reports, or plugging reports.

Vertical Deviation

1. Regulation requirement: Yes. (Rules 11, 12, & 86)
- (a) When is directional survey necessary? All rotary-drilled wells completed as producers must be surveyed to determine the deviation from vertical (inclination surveys). The first test measurement must be made at a depth not greater than 500 feet from the surface and succeeding points must be made at either 500 feet intervals or the nearest drill bit change not exceeding 1,000 feet. If the cumulative displacement calculated from the surface location exceeds the permitted distance to the nearest lease line, the Commission requires that a directional survey be run. A directional survey is also required on a well permitted as an intentionally deviated wellbore to a predetermined bottom hole location.
- If it becomes necessary to by-pass junk by random deviation, written notice must be given to the appropriate Commissions District Office and Austin Offices and drilling may proceed without interruption.
- (b) Filing of directional survey required? Yes, by survey of company through registered or certified mail from the Commission approved surveying company.

Casing and Tubing

1. Minimum amount required: (Rule 13)
- (a) Surface casing: Yes. Adequate amount to protect usable quality water zones. Depth of usable - quality water determined by the Texas Commission on Environmental Quality.
- (b) Production casing: Yes. The production casing shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil saturated portion of the reservoir below the gas-oil contact.
2. Minimum amount of cement required:
- (a) Surface casing: Yes. Circulate to surface.
- (b) Production casing: Yes, at least 600 feet above shoe; also 600 feet above shallowest productive horizon.
- (c) Setting time: Yes. For surface casing, compressive strength must be at least 500 psi at the shoe prior to drill out.
3. Tubing requirements:
- (a) Oil wells: Yes. All flowing oil wells must be produced through tubing. The bottom of the tubing must not be

higher than 100 feet above the producing zone nor more than 50 feet above the top of a liner. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small thru-tubing type tools may be used to perforate, complete, plug back, or recompleat without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet above the top of the perforated or open-hole interval actually open for production in the well bore. In no case shall tubing be set at a depth of less than 70% of the distance from the surface to the top of the completion interval.

- (b) Gas wells: No.
- (c) Injection/Disposal wells: Yes. Injection wells must be equipped with tubing set on a mechanical packer with the packer set no higher than 200 feet below the top of cement behind the production casing and at least 150 feet below the base of useable quality water. Disposal wells must be equipped with tubing set on a mechanical packer with the packer set no higher than 100 feet above the permitted disposal interval. If there are permeable zones between the proposed packer setting depth and the injection interval, the packer must be set below the permeable zones or the permit application must be amended to include those permeable zones in the proposed injection interval.

Completion

1. Completion report required: Yes. (Rule 16)
 - (a) Time limit: Within 30 days after completion of well or the plugging of such well, if the well is dry hole.
 - (b) Where submitted: Railroad Commission, appropriate District Office, in duplicate.
2. Well logs required to be filed: A porosity or resistivity log run over the entire wellbore or in the alternative, if no such log is run over the entire wellbore, the log which is the most complete of such logs run (effective date February 28, 1986). In addition, if well is deepened a copy of basic electric log run after September 1, 1985 should be submitted if such log is run over a deeper interval than the interval covered by a basic electric log already on file.
 - (a) Time limit: With the completion or plugging report.
 - (b) Where submitted: Railroad Commission, Austin, TX.
 - (c) Confidential time period: Yes. Rule 16. The owner or operator may request delayed filing of the log(s). Delay of filing may be for one year, and the owner or operator may request an additional filing delay of two years, provided the written request is filed prior to the expiration date of the initial confidentiality period. If a well is drilled on land submerged in state water, an additional filing delay of two years may be requested so that a possible total filing delay of five years may be obtained.
 - (d) Available for public use: Yes, logs received at the RRC after 6/2004 are available for free via the internet. Copies of log indices and well logs also are available through the University of Texas, Bureau of Economic Geology. See <http://www.beg.utexas.edu/mainweb/services/geophylog.htm>
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes. (Rule 6)
 - (a) Approval obtained: Multi-completion application.
4. Commingling in well bore: (Rule 10) No, except that authority to commingle separate fields/reservoirs may be granted after notice. No hearing necessary unless application is protested, administratively denied, or operator requests hearing.

Oil Production

1. Definition of an oil well: (Rule 79) Any well which produces one (1) barrel or more crude petroleum oil to each one hundred thousand (100,000) cubic feet of natural gas.
2. Potential tests required: Yes.

- (a) Time interval: 10 days after test is completed.
 - (b) Witness required: Notice to Railroad Commission is required in advance so Railroad Commission may witness at its discretion.
3. Statewide allowable: Yes. Production factor is at 100% for all fields.
- (a) Pool allowable: Yes. MER for specific fields.
 - (b) Well allowable: Yes. By Statewide Rule 45.
 - (c) Exempt allowable: Yes. Special exempt after notice and hearing; marginal by statute; discovery by Statewide Rule.
4. Maximum gas-oil ratio: (Rule 49) Yes, 2,000 cubic feet per one barrel of oil; can be higher or lower after notice and hearing.
- (a) Provision for limiting gas-oil ratio: Yes. Gas limit per well. Maximum oil allowable times maximum gas-oil ratio.
 - (b) Exception to limiting gas-oil ratio: Yes, after notice and hearing.
5. Bottom-hole pressure test reports required: (Rule 41) Required on the discovery oil well in any new field and must be filed on prescribed form and sent in with new field application.
- (a) Periodical bottom-hole pressure surveys: Some circumstances.
6. Commingling oil from different leases in common facilities: (Rules 26 & 27) Yes, on application Form P-17, common facilities can be authorized for a common operator subject to separate measurement into the facility. Separate measurement may not be required if royalty and working interest owners are identical in ownership between leases to be commingled or notice and opportunity for hearing is provided to all interest owners.
7. (Rule 32) No gas from any well may be permitted to escape into the air after the expiration of 10 days from the time the gas is encountered in the well, or 10 days from the time of perforating the casing opposite a gas-bearing zone if casing is set through the zone, whichever is later. Exceptions may be administratively granted.
8. Measurement involving meters: Yes. (Rules 26 & 27)
9. Production reports:
- (a) By lease: Yes, for oil wells.
 - (b) By well: No.
 - (c) Time limit: Report filed by end of month following month covered.

Gas Production

1. Definition of a gas well: (Rule 79) Any well (a) which produces natural gas not associated or blended with crude petroleum oil at the time of production, or (b) which produces more than one hundred thousand (100,000) cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon or (c) which produces natural gas from a formation or producing horizon productive of gas only encountered in a well bore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one (1) barrel or more of crude petroleum oil per one hundred thousand (100,000) cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.
2. Pressure base 14.65 psia @ 60 degrees F.

3. Initial potential tests: Yes. (Rule 28)
 - (a) Time interval: 30 days from date of completion, allowable will go back only 15 days. (Rule 16, 28a, 31(a)(B))
 - (b) Witness required: Notice to Railroad Commission is required in advance so Railroad Commission may witness at its discretion.
4. Statewide allowable: No.
 - (a) Pool allowable: Market demand determined by reservoir.
 - (b) Well allowable: Yes. (Based on allocation formula and market demand.) Allocation formula can be suspended when all operators in field consent and have market for 100% of the well's capability.
 - (c) Special allowable: Yes. On special application to prevent waste. Also wells capable of producing 100 MCF or less per day are eligible for administrative special allowable as well as those capable of 250 MCF per day, or less in prorated fields with no special field rules. Also, wells whose average monthly production during the last six consecutive months falls below a cutoff percentage determined by the Commission of the well's top allowable.
5. Bottom-hole pressure test reports required: Yes (may be calculated).
 - (a) Periodical bottom-hole pressure surveys: On new field discoveries and in fields where BHP is part of the allocation formula.
6. Commingling of gas from different wells in common facilities: Yes. On application, Form P-17, common facilities can be authorized for one or more operators subject to notice of application and opportunity for hearing. Separate measurement may not be required if royalty and working interest owners are identical in ownership between leases to be commingled or notice and opportunity for hearing is provided all interest owners.
7. No gas from any well may be permitted to escape into the air after the expiration of 10 days from the time the gas is encountered in the well, or 10 days from the time of perforating the casing opposite a gas-bearing zone if casing is set through the zone, whichever, is later. Exceptions by rule or may be administratively granted upon application.
8. Measurement involving meters: Yes.
9. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Report filed by end of month following month covered.

Environmental Programs

1. The Railroad Commission of Texas has sole regulatory responsibility for preventing the pollution of surface and subsurface water in the state by activities associated with the exploration, development, and production of oil, gas, or geothermal resources. This responsibility includes the management of wastes generated by oil, gas, and geothermal operations. The scope of the Commission's jurisdiction over these wastes is described in detail in statewide Rule Section 3.30 (16 TAC Section 30, Memorandum of Understanding between the Railroad Commission of Texas, and the Texas Commission on Environmental Quality). The rule became effective May 31, 1998.
2. The Commission's water protection and waste management programs for oil and gas operations are administered principally through the Technical Permitting Section, the Site Remediation Section, and the Field Operations Section of the Oil and Gas Division.

Technical Permitting administers the Commission's permitting programs for drilling of wells and for injection wells and other methods of management of oil and gas wastes. The Site Remediation Section coordinates state-managed, operator-

funded, and voluntary site remediation programs. The section also administers selected grants, provides technical support to other sections of the Oil and Gas Division and coordinates with other state and federal agencies on environmental matters.

Field Operations coordinates the activities of the Oil and Gas Division's nine district offices in inspecting oil and gas operations and enforcing the Commission's rules. Additionally, the section coordinates Oil Field Cleanup -funded well plugging and salvage activities.

3. The Commission administers that portion of the federal Underground Injection Control Program relating to injection wells used for disposal of oil and gas wastes (Statewide Rule 9), enhanced recovery of oil and gas (Statewide Rules 46), and underground storage of hydrocarbons (Statewide Rules 95, 96, and 97). EPA approved the Commissions' UIC program for these wells on April 23, 1982. The Commission also has jurisdiction over brine mining injection wells and the EPA approved the brine mining program application in 2004. In 2006, the Commission processed permit applications for 2054 injection wells and monitored the status and operation of more than 50,784 permitted injection wells. The injection of exploration and production wastes into solution-mined salt caverns is an innovative disposal methodology that is permitted by the Commission. The Commission has issued permits for eleven disposal facilities. The Commission's regulation of disposal of E & P wastes into caverns has drawn interest from other states and the Minerals Management Service. Both federal officials and officials from other states have heralded the Commission's UIC program as a model of efficiency and effectiveness.

The Commission regulates the underground storage of hydrocarbons in salt caverns and depleted reservoirs to protect the environment and ensure public safety (Statewide Rules 95, 96, and 97). Texas is a regional center for underground hydrocarbon storage. Solution-mined caverns in both bedded and domal salt are extensively used for long-term, seasonal, and short-term storage. Current working gas storage in Texas is 372 bcf. Growth in storage capacity and deliverability largely reflects the addition of new cavern storage wells.

Under Statewide Rule 8, the Commission regulates the management and reuse of oil and gas waste at the surface. Methods of storage and disposal include the use of pits, landfarms and surface discharge. All pits and disposal methods must be specifically authorized by rule or be individually permitted. Management also includes the permitting of commercial oil and gas waste haulers.

The Commission regulates the management of tank bottoms and other hydrocarbon wastes at reclamation plants under Statewide Rule 57. A reclamation plant requires a permit to operate. The Commission regulates commercial recycling facilities that convert oil and gas wastes into new commercial products (such as road base) under a new rule (Chapter 4, Subchapter B), which became effective on December 4, 2006. All wastes generated must be disposed of in accordance with Statewide Rules 8, 9, and 46.

In the fall of 1993, the Commission adopted by rule standards and procedures for clean up of crude oil spills in non-sensitive areas (Statewide Rule 91).

In 2003, the Commission adopted a new rule (Chapter 4, Subchapter F) for oil and gas naturally occurring radioactive material (NORM). In Texas, the RRC regulates disposal of oil and gas NORM waste and the Texas Department of State Health Services (TDSHS), regulates most other aspects of oil and gas NORM management. In 2003, the RRC adopted new regulations for identification and labeling of oil and gas equipment contaminated with NORM waste. These regulations were developed in consultation with the TDSHS. NORM that occurs in produced water is exempt from TDSHS rules applicable to transportation and storage and is not subject to special NORM disposal regulations. The rule is based on risk of exposure to NORM. The rule authorizes certain disposal methods for NORM oil and gas waste under certain conditions, and requires specific authorization for other disposal methods. Staff from the RRC, TDSHS, and the Texas Commission on Environmental Quality (TCEQ) meet quarterly to discuss radiation issues and to coordinate efforts. In addition, the Texas Radiation Advisory Board (TRAB), which consists of 18 members appointed by the governor, is charged with providing recommendations and technical advice to the RRC, the TDSHS, and TCEQ.

The Commission also regulates the management of nonexempt oil and gas waste that is determined to be hazardous waste (Rule 98). Rule 98 became effective on April 1, 1996. Rule 98 standards are applicable only to generators and transporters of hazardous oil and gas waste. Rule 98 contains no provisions for permitting hazardous waste treatment, storage, or disposal facilities. Rule 98 is as stringent as the federal hazardous waste regulations under the Resource Conservation and Recovery Act, Subtitle C (RCRA). The Commission has contacted EPA regarding delegation of RCRA authority.

The Commission's water protection rules for oil and gas operations also include rules for drilling, casing, cementing, completing, and plugging wells (Statewide Rules 13, 14, 99, and 100). These rules incorporate state-of-the-art procedures for protecting usable quality water zones.

4. The Commission vigorously enforces its oil and gas rules despite its limited resources. The Oil and Gas Division had an average of 126 field inspectors, well pluggers, and cleanup coordinators located at nine District Offices across the state during 2006. In 2006, these inspectors performed 118,109 inspections and discovered 22,772 pollution violations. Also, a sophisticated automatic data processing system helps the Commission record and track compliance.

All violations are actively pursued until compliance is achieved. The various enforcement mechanisms the Commission uses include violation letters, pipeline severances, zero allowables, seals, and administrative penalties of up to \$10,000 per day. The Commission selects the appropriate enforcement mechanism to address a particular violation based on various factors, such as the severity and duration of the violation.

5. The cornerstone of the Commission's Oil and Gas Division environmental effort are two programs funded by the Oil Field Cleanup (OFCU) Fund: Well Plugging and Site Remediation. These programs have been instrumental in protecting the Texas environment by properly plugging or remediating abandoned oil field sites.

The Oil Field Cleanup Well Plugging and Site Remediation programs have been and continue to be, effective instruments for implementation of the RRC's responsibility to protect the environment from pollution associated with oil and gas operations. While the wells and sites are designated as state funded, the Oil Field Cleanup Fund derives funding entirely from fees, penalties and other payments from the oil and gas industry. One major source is the regulatory fee assessed on the production of oil and gas, which is 5/8 (eff. 9-1-01) of a cent per barrel of oil and 1/15 (eff. 9-1-01) of a cent per thousand cubic feet of gas.

The Commission supplements the Oil Field Cleanup Fund with EPA grants to plug additional wells in the drainage basins of stream, reservoir, and bay segments impaired with chlorides, sulfates, and total dissolved solids. These EPA grants are funneled through the Texas Commission on Environmental Quality (TCEQ) and the Railroad Commission works closely with the TCEQ to obtain approval of these grants. Since September 2000, the RRC has successfully obtained approval from the EPA to plug 1,080 wells with grant funds totaling approximately \$10.5 million in various stream segments across the state. The actual number of wells plugged through the end of May of 2007 is 1,461 with a total plugging cost of \$8,132,961.

The Commission has entered into inter-agency contracts with the Texas General Land Office (GLO) to plug wells on State submerged lands. These contracts are sister agency partnerships that call for the RRC to use its expertise in well plugging operations and for the GLO to fund the well plugging operations on State submerged lands. Since September 2000, the RRC and the GLO have partnered to plug 62 bay and offshore wells for approximately \$9.5 million.

During the last 20 years, the RRC has made a committed effort through compliance audits, response to citizen complaints and focused sweeps, to identify the unplugged oil and gas wells that present the greatest threat to the environment. Based on a highly effective prioritization scheme the wells with the greatest possible impact to the environment are being properly plugged. During 2006, the RRC plugged 1,824 wells using OFCU Funds, EPA grants, and GLO funds. Between September 1, 1983 and August 31, 2006, the RRC has plugged 26,078 wells at a cost of over \$122,000,000 from all sources of funds.

Site Remediation, which became operational during fiscal year 1992, performs cleanup activities on abandoned routine, emergency and complex sites. Routine sites, which are often remediated in concert with well pluggings, commonly consist of pit closure, tank removals and minor surface spill cleanups. Emergency sites require immediate actions to protect human health or the environment. Complex sites typically include detailed assessment activities (often requiring several mobilizations), a determination of the source of the contamination and recommended remedial alternatives.

Similar to the Well Plugging Program, the Site Remediation Section prioritizes sites based on the present or possible future impact to the environment. With larger sites, staff is often challenged with determining if the source of

pollution is natural or man-made, which potential operator is responsible, how to evaluate the site and which remedial method is appropriate for the situation. The Site Remediation Section has completed 3382 clean-up activities from the program's inception in 1992 to the close of fiscal year 2006.

Another important function of the Commission's Site Remediation Section is the management of the Operator Cleanup Program (OCP). Operator cleanups are complex assessment and remediation activities voluntarily conducted by a responsible operator, usually at environmentally sensitive sites. The program ensures that pollution outside of SWR 91 non-sensitive area oil spill cleanup requirements and beyond routine SWR 8 cleanups and closures are addressed promptly and adequately. Oversight of OCP activities is usually by staff in Austin headquarters and District Office (DO) staff. The majority of the projects are long-term remediation projects that require specialized skills to review and manage. The Commission tracks approximately 500 complex operator cleanups. These projects involve frequent sampling, reporting, and evaluation to ensure final cleanup is protective of the public health, safety and the environment.

An added incentive for cleanup outside of the OCP was enabled by Senate Bill 310, 77th Legislature (2001), which amended Texas Natural Resources Code, Chapter 91, by adding new Subchapter O, specifically authorizing the Commission to establish a Voluntary Cleanup Program (VCP) that is self-funded through the collection of application and oversight fees and that these fees be deposited to the Oil Field Cleanup Fund. Railroad Commission rules regarding the VCP were adopted in June 2002 (16 TAC, Chapter 4, Subchapter D). The purpose of the VCP is to provide an incentive to lenders, developers, owners, and operators to remediate soil and water impacted by activities over which the Commission exercises jurisdiction by removing the liability to the lenders, developers, owners, and operators who did not cause or contribute to the contamination.

In return for the release of liability, the State offsets oversight costs through the collection of fees, reduces the need for State-managed cleanup activities, and expedites the return of contaminated properties into productive use. As of August 31, 2006, there were 37 active VCP sites. Since program inception in the summer of FY02, 22 sites have been cleaned up and certificates of completion issued as of July 25, 2007.

The pursuit of environmental investigation and cleanup grants has been a direct outgrowth of efforts by the RRC to leverage the OFCU fund and obtain cleanup for sites that might not otherwise be addressed or fall to the fund. Currently there are four grants awarded to Site Remediation: one Brownfield Subtitle C State Response Program grant, and three non-Point Source Watershed grants for a total of \$3.4 million. Each grant pursued and awarded either directly or indirectly by the EPA leverages private party cleanups and the OFCU fund and, ultimately, leads to the cleanup and closure of oil and gas contamination sites.

- (a) Testing inactive wells
- (b) Testing requirements: (Rule 14) Any well inactive one year or more that is 25 or more years old must be tested to ensure that it does not present a threat of pollution. Inactive wells seeking 14(b)(2) plugging extensions based on the filing of a W-1X must also be tested before the W-1x extensions can be granted.
- (c) Types of Tests:
 - (1) Fluid level test: Must indicate an adequate separation between the base of usable-quality water and level of fluids within the wellbore. Must be performed annually, except that for W-1X purposes the test must be conducted no earlier than 90 days prior to W-1X filing.
 - (2) Mechanical integrity test: The casing must be tested to a depth at least 250 feet below the deepest usable-quality water, or 100 feet below the calculated top of cement behind the production casing, which ever is deeper.
The casing must be tested to a minimum pressure of 250 psi, and the pressure must be maintained for at least 30 minutes. If successful, no other test is required for 5 years (4 years for W-1X purposes).
- (d) Notification: Appropriate district office a minimum of 48 hours prior to conducting the mechanical integrity or fluid level test.
- (d) Reporting test results: File Commission FORM H-15, "Test on an Inactive Well More than 25 years old".

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: No.
2. Generally a minimum percentage of agreement before approval of voluntary unitization:
 - (a) Working interest: 85%.
 - (b) Royalty interest: 65%.

Taxation

Gas severance tax = 7.5% of the market value
 Gas ad valorem tax = variable by county
 Oil Field Cleanup Regulatory Fee on gas = $1/15^{\text{th}}$ of 1 cent per MCF
 Oil Severance tax = 4.6% of the market value
 Oil ad valorem tax = variable by county
 Oil Field Cleanup Regulatory Fee
 Crude oil/condensate = $5/8^{\text{th}}$ of 1 cent per barrel
 Crude oil regulatory tax = $3/16^{\text{th}}$ of 1 cent per barrel
 Oil spill fee for crude oil/condensate = 2 cents per bbl

1. Tax collecting agency: State Comptroller of Public Accounts, Capitol Station, Austin, TX 78701
2. How tax is computed:
 - (a) Severance:

crude oil/condensate	4.6% of value
natural gas	7.5% of value
 - (b) Regulatory tax:

crude oil	3/16ths of 1 cent per barrel
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 - (c) Oil Field Cleanup Regulatory Fee:

crude oil/condensate	5/8 th of 1 cent per barrel
natural gas	1/15 th of 1 cent per MCF
 - (d) Oil Spill Fee:

crude oil/condensate	2 cents/bbl for each barrel transferred through a "marine terminal" TX coastal waters.
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3. Exemption or reduction of severance tax as follows:
 - (a) Gas from high-cost gas wells (Reduction in tax for first 120 months- high cost gas produced from a well-bore spud or completed after August 31, 1996. Total reduction in tax not to exceed 50% of drilling and completion cost of the well bore (incentive became permanent as of September 1, 2003).
 - (b) Crude oil from some enhanced oil recovery projects (reduction of tax) and an additional reduction for crude oil produced from enhanced recovery using anthropogenic carbon dioxide.
 - (c) Crude oil/gas well gas/casinghead gas produced from wells that are certified by February 28, 2010, as inactive two years (exemption)
 - (d) Incremental oil/casinghead gas from oil leases with minimal oil production in 1996 that improved production between September 1, 1997 and December 31, 1998 (reduction of tax)
 - (e) Marketed casing head gas previously vented or flared (exemption from tax)

4. Statutory citations

- | | | |
|-----|-----------------------------|---|
| (a) | Severance tax
Oil
Gas | Texas State Tax Code, Title 2, Subtitle I
Chapter 202
Chapter 201 |
| (b) | Regulatory Tax | Texas Natural Resources Code (TNRC) Title |
| (c) | Oil Field Cleanup | Regulatory Fee Oil TNRC Title 3, Subtitle A, Chapter 81 |
| (d) | Gas | TNRC Title 3, Subtitle A, Chapter 81 |
| (e) | OSPRA Fee | TNRC Title 2, Subtitle C, Chapter 40 |

Land Leasing Information

1. Leasing Method: Sealed bid.
2. Notice Method: At least 30 days prior to lease sale date, the appropriate board will advertise in at least 4 daily newspapers for at least 3 issues.
3. Minimum bidding \$ (cash bonus): Along with the bonus, each bidder is required to pay by separate check an amount equal to 1 ½% of the bid payable to the commissioner as a special sales fee.
4. Qualification of the bidder: Anybody in good standing with the State Comptroller can submit bids.
5. State Statutes: Chapter 32 and 52 of the Texas Natural Resources Code

Rules: 31 TX ADC
Chapter 9
§151.2
Chapter 201
6. Maximum acres:
7. Contact: Mickey R. Olmstead
E-mail: molmstea@wpgate.glo.state.tx.us

Naturally Occurring Radioactive Material (NORM)

See Environmental Programs for NORM information.

UTAH

Administration

1. State agency: Department of Natural Resources, Division of Oil, Gas and Mining, 1594 W. North Temple, Suite 1210, P.O. Box 145801, Salt Lake City, UT 84114-5801. Phone (801) 538-5340. Fax (801) 359-3940. Web site: www.ogm.utah.gov.
2. Docketing procedure: Petitions requesting a hearing should be filed by the 10th day of each calendar month for docketing of a hearing by the Board or appointed Hearing Examiner at the regularly scheduled meeting during the following calendar month, usually the 4th Wednesday.
 - (a) Emergency orders: Issued by the Division Director or any Board member without notice or hearing. Order effective until the next regularly scheduled meeting of the Board.
 - (b) Notice: Publication given by Board by the 1st day of the month in which the hearing is held, but in no event less than 15 days before the hearing. In addition to published notice, the Board shall give notice by mail to all interested parties.

Bond

1. Compliance bond required: Yes, for active wells on school trust lands and fee or private lands and for disposal facilities.
2. Conditions of active well bond: For the performance of the duty to plug each dry or abandoned well, to repair each well causing waste or pollution, and to maintain and restore the well site.
 - (a) Amount per well:

<u>Well Depth (ft)</u>	<u>Bond Amount (\$)</u>
0 - 1,000	\$1,500
1,000 - 3,000	\$15,000
3,000 - 10,000	\$30,000
Greater than 10,000	\$60,000
 - (b) Amount of blanket bond: Wells < 1,000 ft. in depth - \$15,000
Wells > 1,000 ft. in depth - \$120,000

Full cost bonding may be required for shut-in or temporarily abandoned wells that are found in violation of Rule R649-3-36.

3. Conditions of disposal facility bond: Disposal facilities, other than injection wells, shall be bonded in order to protect the State and oil and gas producers from unnecessary liabilities and cleanup costs in the future.
 - (a) Bond amounts are calculated according to the amount of pit area, pit storage capacity and stockpiled waste assessed at the following rates:
 - (i) \$14,000 per acre of pit, plus
 - (ii) \$1.00 per barrel of produced water for one-quarter of the total storage capacity of the facility, plus
 - (iii) \$30 per cubic yard of solid or semi-solid waste material stockpiled at the facility.
 - (b) The initial and minimum bond amount for any facility is \$10,000 and the total bond amount will be as calculated in part (a). Disposal facility operators may request incremental bond posting above the initial amount at a rate of \$0.02 per barrel of liquid or \$0.60 per cubic yard of solid/semi-solid waste material accepted for disposal at the facility.
 - (c) The incremental rules in part 3 a & b apply to operators of pits in operation prior to 1997 and do not apply to any new construction or operators. All new operators and pits are being bonded at full cost. Although this is not yet a

rule it is a policy that is strictly adhered to.

Spacing

1. Spacing requirements: Yes. Statewide location and siting of vertical wells and statewide spacing for horizontal wells.
 - (a) Vertical well density: In the absence of special orders of the Board establishing drilling units or authorizing different well density or location patterns for particular pools or parts thereof, each oil and gas well shall be located in the center of a 40-acre quarter quarter section, or a substantially equivalent lot or tract or combination of lots or tracts as shown by the most recent government survey, with a tolerance of 200 feet in any direction from the center location.
 - (d) Lineal setbacks for vertical wells: No oil or gas well shall be drilled less than 920 feet from any other well drilling to or capable of producing oil or gas from the same pool.
 - (e) Horizontal well density: A temporary 640 acre spacing unit consisting of the governmental section in which a horizontal well is located, is established for orderly development of an anticipated pool.
 - (f) Lineal setbacks for horizontal wells: In the absence of special orders of the Board, no portion of the horizontal interval within the potentially productive formation shall be closer than 660 feet to a drilling or spacing unit boundary, federally unitized area boundary, uncommitted tract within a unit, or boundary line of a lease which is not committed to the drilling of such a horizontal well. Any horizontal interval shall not be closer than 1,320 feet to any vertical well completed in and producing from the same formation.
2. Exceptions: Yes.
 - (a) Basis: Not specifically defined but may include geological topographical, cultural, archeological, and others as requested by the operator.
 - (b) Approval: Granted administratively providing that evidence of necessity, verification of lease ownership and the written consent from all owners within a 460-foot radius of the proposed well location or owners of directly or diagonally offsetting drilling units are received by the Division.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require approvals for:
 - (a) Drilling a producing or service well? Yes.
 - (b) Seismic drilling? Yes.
 - (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes.
 - (e) Reentry of an abandoned well. Yes.
2. Permit fee:
 - (a) Drilling: None.

- (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Yes.
- (a) When is directional survey necessary? (1) Intentional deviation and directional drilling programs and, (2) at the discretion of the Division Director when it is determined or questioned that the tolerances for vertical drilling are exceeded.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
- (a) Surface casing: Yes. (1) To a depth below all known or reasonably estimated, utilizable, domestic, fresh water levels, (2) to a depth sufficient to prevent blowouts or uncontrolled flows.
 - (b) Production casing: As necessary.
2. Minimum amount of cement required:
- (a) Surface casing: Yes.
 - (b) Production casing: Yes, special circumstances.
 - (c) Setting time: No.
3. Tubing requirements:
- (a) Oil wells: As necessary.
 - (b) Gas wells: As necessary.

Completion

1. Completion report required: Yes.
- (a) Time limit: 30 days after cessation of operations on abandonment or completion of any well drilled for the production of oil or gas.
 - (b) Where submitted: Division of Oil, Gas and Mining.
2. Well logs required to be filed: Yes.
- (a) Time limit: 30 days.
 - (b) Where submitted: Division of Oil, Gas and Mining.

- (c) Confidential time period: Yes, one year, if requested.
- (d) Available for public use: Yes.
- (e) Log catalog available: Yes.
- 3. Multiple completion regulation: Yes.
 - (a) Approval obtained: Administrative approval or Board hearing.
- 4. Commingling in well bore: Yes.
 - (a) Approval obtained: Administrative approval or Board hearing.

Oil Production

- 1. Definition of an oil well: Any well capable of producing oil in substantial quantities.
- 2. Potential tests required: Yes. In conjunction with gas-oil ratio (GOR) test.
 - (a) Time interval: 15 days following completion or recompletion.
 - (b) Witness required: As necessary.
- 3. Statewide allowable: No.
 - (a) Pool allowable: Yes. (1) To the extent provided by the granting of well spacing or spacing exception orders by the Board and, (2) by order of the Board to protect correlative rights, prevent waste, preserve reservoir pressure and obtain maximum recovery.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
- 4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Yes. Determined on individual well basis for purposes of conservation or prevention of waste.
 - (b) Exception to limiting gas-oil ratio: Yes. If conclusively proven reservoir or energy waste does not occur.
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: Yes.
- 7. Measurement involving meters: Yes.
- 8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: 45 days.

Gas Production

1. Definition of a gas well: Any well capable of producing gas in substantial quantities that is not an oil well.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: 15 days following completion or recompletion of a well.
 - (b) Witness required: As necessary.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes.
 - (i) To the extent provided by the granting of well spacing or spacing exception orders by the Board and,
 - (ii) By order of the Board to protect correlative rights, prevent waste, preserve reservoir pressure and obtain maximum recovery.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: Yes. As requested by the Division.
6. Commingling of gas in common facilities: No.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: 45 days.

Water Disposal

1. State agencies that control disposal of produced salt water: Division of Oil, Gas and Mining.

Unitization

1. Compulsory unitization of all or part of a pool or common sources of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: 70%.
 - (b) Royalty interest: 70%.

- (4) the first six months of production for development wells started after January 1, 1990;
 - (5) governmental interests (royalties); and
 - (6) oil or gas used in drilling or completion operations for recycling or repressuring purposes.
- (b) Conservation Tax: - No tax is imposed upon:
- (1) governmental interests (royalties); and
 - (2) oil or gas used in drilling or completion operations or for recycling or repressuring purposes.
- (c) Ad valorem property Tax: - No tax is imposed upon exempt federal, state and Indian royalty interests.
- (d) Recompletion or Workover Tax Credit: -

Working interest owners participating in the expenses of recompletions or workovers are entitled to a severance tax credit equal to 20% of the amount paid for the recompletion or workover. The tax credit is limited to \$30,000 per well during each calendar year.

- (e) Incremental production incentive: -

A 50% reduction in the severance tax rate is imposed upon the incremental production achieved from an enhanced recovery project initially approved by the board as a new or expanded enhanced recovery project on or after January 1, 1996.

4. Name of tax: Severance, Conservation, and Ad Valorem.

5. Statutory Citation:

Severance:	Utah Code Ann. Section 59-5-101 through 59-5-119.
Conservation:	Utah Code Ann. Section 40-6-14.
Ad Valorem:	Utah Code Ann. Section 59-2-201, and 59-2-210.

Land Leasing Information

1. Leasing Method: Competitive sealed bids.
2. Notice Method: Notice mailed to mailing list. Ad placed in Rocky Mountain Oil and Gas Journal.
3. Minimum bidding \$ (per acre): \$1 per acre on trust lands. Depends on tract on sovereign lands.
4. Qualification of the bidder: Anyone can submit a sealed bid. Corporations must be registered in Utah.
5. State Statutes: See contact information.
6. Maximum acres: Sovereign lands are limited by statute and cannot exceed approximately 2,560 acres. Trust lands do not have a limit.
7. Contact: School and Institutional Trust Lands Administration: Phone: (801) 538-5100
Forestry, Fire and State Lands: Phone: (801) 538-5555

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Environmental Quality, Division of Radiation Control, P.O. Box 144850, Salt Lake City, UT 84114-4850. Phone: (801) 536-4250, Fax: (801) 533-4097.
2. Relevant Statute/Regulations: R313-19-13(2)(a)(i)(B) provides that naturally occurring radioactive material (NORM)

containing less than 15 picocuries per gram radium-226 is exempt from regulation. Amounts greater than this are subject to licensing.

3. Scope: Current rules are somewhat limited in scope. The Conference of Radiation Control Program Directors (CRCPD) has released draft rules for the licensing and regulation of Technologically Enhanced Naturally Occurring Radioactive Materials (TENORM). The Division of Radiation Control supports this effort.
4. Licensing: Requirements for licensing are found in the Utah Rules at R313-22.
5. Cleaning Equipment: Licensees are allowed to clean and release equipment for unrestricted release. Methods and procedures are generally approved as part of the licensing process but they may also be approved when a licensee undergoes decommissioning.
6. Disposal of Waste: Licensed radioactive waste is generally disposed of by transfer to a licensed low-level radioactive waste land burial facility. Radiation Control Rules in R313-15-1002 provide for other disposal procedures (on-site burial).
7. Subsequent Use of Equipment: Contaminated equipment may be released for unrestricted use once the licensee has decontaminated the equipment Division standards. The standards used as those found in Nuclear Regulatory Commission Regulatory Guide 1.86 (June 1974).
8. Subsequent Use of Materials: Licensed materials may be transferred to others for subsequent use provided the transfer is in accordance with R313-19-41.
9. Release/Sale of NORM-Contaminated Land: Licensed facilities (land) must meet decommissioning clean-up standards before it may be used for unrestricted purposes.
10. Projected Volume of stored NORM in the State: Unknown.
11. Other: See Utah Radiation Control Rules on the Internet at: www.deq.state.ut.us/eqrad/drc_hmpg.htm.
12. Respondent: Craig Jones
Phone: (801) 536-4264

VIRGINIA

Administration

1. State agency: Department of Mines, Minerals and Energy, Division of Gas and Oil, 202 N. 9th St., 8th Floor, Richmond, VA 23219-3402. Phone (276) 676-5423.
2. Docketing procedure:

Hearing an objection to permit applications held not less than 20 or more than 30 days from original filing of objection. Section 45.1-361.35, Virginia Gas and Oil Act.

Hearing on application for pooling order/drilling units held at next monthly Virginia Gas and Oil Board meeting if application made 30 days in advance. Section 45.1-361.20, Virginia Gas and Oil Act, and Regulation 4 VAC 25-160-30.

- (a) Emergency orders: Yes. The Gas and Oil Inspector may issue an emergency order for 30 days. Notice must be given and a hearing held to make emergency orders permanent. Section 45.1-361.27, Virginia Gas and Oil Act.

- (b) Notice:

The Gas and Oil Inspector must give notice ten days prior to a hearing on an objection to a permit application. Section 45.1-361.35, Virginia Gas and Oil Act.

Applicants for a hearing before the Board must give notice to all gas, oil, coal or mineral owners on tracts subject to the hearing at least 30 days in advance. Section 45.1-361.19, Virginia Gas and Oil Act, and Regulation 4 VAC 25-160-30.

The Board must publish notice of hearings at least 20 days in advance. Section 45.1-361.19, Virginia Gas and Oil Act.

Bond

1. Compliance bond required: Yes. Section 45.1-361.31, Virginia Gas and Oil Act.
2. Conditions of bond: Bond shall remain in effect to insure compliance with all oil and gas laws and regulations. Plugging portion of bond held for life of well; stabilization portion can be released by Gas and Oil Inspector when area stabilized. Section 45.1-361.31, Virginia Gas and Oil Act.
 - (a) Amount per well or other operation: An amount sufficient to plug the well and restore the site, not less than \$10,000 per well plus \$2,000 per acre of disturbed land. Section 45.1-361.31, Virginia Gas and Oil Act.
 - (b) Amount of blanket bond: One to 15 wells, \$25,000; 16 to 30 wells, \$50,000; 31 to 50 wells, \$75,000; 51 or more wells, \$100,000. Section 45.1-361.31, Virginia Gas and Oil Act.

Spacing

1. Spacing requirements: Yes. In the absence of field rules established by the Virginia Gas and Oil Board, statewide spacing, based on minimum distance between wells, is as follows:
 - (a) For oil: not within 1,250 ft. of another well completed in the same pool, and not within 625 ft. of the boundary of acreage supporting the well.
 - (b) For gas: not within 2,500 ft. of another well completed in the same pool, and not within 1,250 ft. of the boundary of acreage supporting the well.

- (c) For coalbed methane gas wells: not within 1,000 ft. of another coalbed methane gas well, and not within 500 ft. of the boundary of acreage supporting the well.
 - (d) For coalbed methane gas wells located in the gob: not within 500 ft. of another coalbed methane gas well completed in the gob and not within 250 ft. of the boundary of acreage supporting the well. Section 45.1-361.17, Virginia Gas and Oil Act.
2. Exceptions: Yes.
- (a) Basis: The Virginia Gas and Oil Board hears unique testimony regarding each application for exception and renders a decision based on that testimony.
 - (b) Approval: All exceptions to statewide spacing must be approved by the Board and detailed in an order issued by the Board. Section 45.1-361.17, Virginia Gas and Oil Act, and Regulation 4 VAC 25-160-60.

Pooling

- 1. Authority to establish voluntary: Yes, Section 45.1-361.18, Virginia Gas and Oil Act.
- 2. Authority to establish compulsory: Yes, by Virginia Gas and Oil Board.
 - (a) For gas or oil: Section 45.1-361.21, Virginia Gas and Oil Act, and Regulation 4 VAC 25-160-70.
 - (b) For coalbed methane gas: Section 45.1-361.21 and 45.1-361.22, Virginia Gas and Oil Act, and Regulation 4 VAC 25-160-70 and 4 VAC 25-160-80.

Drilling Permit

- 1. Require permits for:
 - (a) Drilling a producing or service well: Yes. Section 45.1-361.29, Virginia Gas and Oil Act, and Regulation 4 VAC 25-150-10.
 - (b) Seismic drilling: Yes. Section 45.1-361.29, Virginia Gas and Oil Act, and Regulation 4 VAC 25-150-10.
 - (c) Recompletion: Yes. Section 45.1-361.29, Virginia Gas and Oil Act, and Regulation 4 VAC 25-150-10.
 - (d) Plugging and abandoning: Yes. Section 45.1-361.29, Virginia Gas and Oil Act.
 - (e) Permit transfers: Yes. Regulation 4 VAC 25-150-120.
- 2. Permit fee:
 - (a) Drilling and gathering pipelines: \$260. (Plus a \$50.00 surcharge for the Orphaned Well Fund) Section 45.1-361.29, Virginia Gas and Oil Act.
 - (b) Seismic drilling: \$130. Section 45.1-361.29, Virginia Gas and Oil Act.
 - (c) Recompletion: \$130. Section 45.1-361.29, Virginia Gas and Oil Act.
 - (d) Permit transfer: \$65. Regulation 4 VAC 25-150-120.
 - (e) New permits for wells and pipelines: \$50 to the Orphaned Well Fund. Section 45.1-361.40, Virginia Gas and Oil Act.
 - (f) Permit Modification: \$130. Section 45.1-361.29, Virginia Gas and Oil Act.
- 3. Require filing report of work performed: Yes. Section 45.1-361.27, Virginia Gas and Oil Act, and Regulation 4 VAC 25-150-210, 4 VAC 25-150-220, 4 VAC 25-150-360, 4 VAC 25-150-380, 4 VAC 25-150-400, 4 VAC 25-150-420, 4 VAC 25-150-460 as applicable.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? For any well penetrating a mineable coal seam and having an inclination greater than 1° from true vertical. Regulation 4 VAC 25-150-280; when intentionally deviated, when deviated outside of a drilling unit boundary or on an exception location, Regulation 4 VAC 25-160-200.
 - (b) Filing of survey required: Yes. Regulation 4 VAC 25-150-360; Regulation 4 VAC 25-160-200.

Casing and Tubing

1. Minimum amount required: Yes. Regulation 4 VAC 25-150-530 and 4 VAC 25-150-610.
 - (a) Surface casing: Yes, minimum 300' or 50' below the lowest groundwater water zone whichever is deeper. Exploratory well or gas well in Tidewater region: Virginia Code Section 62.1-195.1.
 - (b) Production casing: For coalbed methane gas wells, Regulation 4 VAC 25-150-620.
2. Minimum amount of cement required: Yes. Regulation 4 VAC 25-150-530 and 4 VAC 25-150-610.
 - (a) Surface casing: Yes.
 - (b) Production casing: No.
 - (c) Setting time: Minimum of 8 hours and allow the cement to achieve a calculated compressive strength of 500 psi before drilling. Regulation 4 VAC 25-150-530 and 4 VAC 25-150-610.
3. Tubing requirements: No.
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes. Regulation 4 VAC 25-150-360.
 - (a) Time limit: Within 30 days of completion. Regulation 4 VAC 25-150-10.
 - (b) Where submitted: Division of Gas and Oil.
2. Well logs required to be filed: Yes. Regulation 4 VAC 25-150-360.
 - (a) Time limit: Driller's log within 30 days of reaching total depth. Electric log within 2 years. Regulation 4 VAC 25-150-360.
 - (b) Where submitted: Division of Gas and Oil.
 - (c) Confidential time period: Yes, the earlier of 90 days after completion or 18 months after well reaches total depth automatic or 2 years after completion or 4 years after well reaches total depth if well is certified as exploratory. Section 45.1-361.6, Virginia Gas and Oil Act.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
3. Multiple completion regulation: No.
 - (a) Approval obtained: Yes.

4. Commingling in well bore: Yes.
- (a) Approval obtained: None.

Oil Production

1. Definition of an oil well: Any well that produces or appears capable of producing a ratio of less than 6,000 cubic feet of gas to each barrel of oil on the basis of initial gas-oil ratio test. Regulation 4 VAC 25-150-10.
2. Potential tests required: Yes. Regulation 4 VAC 25-160-200.
 - (a) Time interval: None.
 - (b) Witness required: No.
3. Statewide allowable: No.
 - (a) Pool allowable: Yes, for conventional gas or oil; No, for coalbed methane gas.
 - (b) Well allowable: Yes, for conventional wells; No, for coalbed methane gas wells.
 - (c) Exempt allowable: Yes.
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Yes.
 - (b) Exception to limiting gas-oil ratio: Yes.
5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: Yes.
7. Measurement involving meters: Yes. Regulation 4 VAC 25-150-400.
8. Production reports: Yes. Section 45.1-361.38, Virginia Gas and Oil Act, and Regulation 4 VAC 25-150-210 and 4 VAC 25-150-220.
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: Monthly and Annually.

Gas Production

1. Definition of a gas well: Any well which produces or appears capable of producing a ratio of 6000 cubic feet (6 mcf) of gas or more to each barrel of oil on the basis of a gas-oil ratio test. Regulation 4 VAC 25-150-10.
2. Pressure base 14.73 psig @ 60 degrees F.
3. Initial potential tests: Yes. Regulation 4 VAC 25-160-200.
 - (a) Time interval: None.
 - (b) Witness required: No.
4. Statewide allowable: No.
 - (a) Pool allowable: Yes, for conventional gas or oil; No, for coalbed methane gas.
 - (b) Well allowable: Yes, for conventional gas or oil; No, for coalbed methane gas.

- (c) Exempt allowable: Yes.
- 5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling of gas in common facilities: Yes.
- 7. Measurement involving meters: Yes. Regulation 4 VAC 25-150-400.
- 8. Production reports: Yes. Section 45.1-361.38, Virginia Gas and Oil Act, and Regulation 4 VAC 25-150-210 and 4 VAC 25-150-220.

Water Disposal

- 1. State agencies that control disposal of produced salt water: Division of Gas and Oil, Regulation 4 VAC 25-150-420, and Department of Environmental Quality. Both state and federal permits are required for a water disposal injection well.
- 2. Injection wells: Yes under EPA primarily.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source of supply: Upon order of the Virginia Gas and Oil Board. Sections 45.1-361.15, 45.1-361.20, 45.1-361.21 and 45.1-361.22, Virginia Gas and Oil Act and Regulation 4 VAC 25-160-50.
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: None set.
 - (b) Royalty interest: None set.

Taxation

Gas severance tax = up to 2.0% of gross receipts
 Local road improvement tax = up to 1.0% of gross receipts
 Total gas tax burden = up to 3.0% of gross receipts

Oil severance tax = 1/2 of 1.0% of gross receipts
 Local road improvement tax (oil coal) = up to 1.0% of gross receipts
 Total oil tax burden = up to 1 1/2 of gross receipts

- 1. Tax collecting agency: Any city or county government.
- 2. How tax is computed: Oil severance tax is computed as 1/2 of 1% of the gross receipts. Gas severance tax is computed up to 2% of gross receipts. There is a Local Road Improvement Tax of up to 1% of gross receipts for both oil coal and gas.
- 3. Exemptions or exceptions: None.
- 4. Name of tax: Severance Tax on Oil; Severance Tax on Gas; Local Coal and Gas Road Improvement and Virginia Coalfield Economic Development Authority Tax.
- 5. Statutory citation: Code of Virginia, § 58.1-3712, 3712.1, 3713, 3713.1, 3713.2, 3713.3 and 3713.4.

Land Leasing Information

1. Leasing Method: Competitive sealed bids.
2. Notice of Method: Notice by publication once a week for 4 successive weeks in at least 2 newspapers of general circulation.
3. Minimum bidding \$ (per acre):
4. Qualification of the bidder:
5. State Statutes: VA ST
 §11-37, §20-1A-6
 §53.1-31
 §59.1-259
6. Maximum acres:
7. Contact:

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Mines, Minerals and Energy, Division of Gas and Oil, P.O. Box 1416, Abingdon, VA 24212. Phone: (276) 676-5423, Fax: (276) 676-5459.
2. Relevant Statute/Regulations: At this time, the Commonwealth of Virginia does not have regulations regarding NORM and does not have nor anticipate proposing regulations for naturally occurring radioactive material in oil and gas production.
3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the state:
11. Respondent: Bob R. Wilson

WASHINGTON

Administration

1. State agency: Department of Natural Resources, Division of Geology and Earth Resources, Olympia, WA 98504-7007. Phone (360) 902-1450.
Ron Teissere, Oil and Gas Supervisor
2. Docketing procedure: Department issues notice of hearing to State Code Reviser's Office, interested parties, and gives public notice in a newspaper at least 20 days before the proposed hearing.
 - a. Emergency orders: Yes. Department can promulgate them with no notice. They cannot be in effect more than 90 days.
 - b. Notice: 20 days. The Department is responsible to give notice.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: Bond is for proper abandonment of well and remains in force until that is accomplished and well site has been reclaimed.
 - a. Amount per well: Not less than \$50,000.
 - b. Amount of blanket bond: Not less than \$250,000.

Spacing

1. Spacing requirements: Yes. Not smaller than the maximum area that can be efficiently drained by one well. Because we have no production, specific limits have never been set.
 - a. Density: Not greater than 160 acres for oil or 640 acres for gas.
 - b. Lineal: Not closer than 500 feet to lease boundary line.
2. Exceptions:
 - a. Basis: Department rules that prescribed location would not produce in paying quantities or that surface conditions would add a burden or hazard.
 - b. Approval: From the department.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - a. Drilling a producing or service well: Yes.
 - b. Seismic drilling: Yes. Blanket permit.
 - c. Recompletion: Yes.
 - d. Plugging and abandoning: Yes, part of drilling permit.
2. Permit fee:

a. Drilling:	<u>Depth (ft)</u>	<u>Amount</u>	<u>Depth (ft)</u>	<u>Amount</u>
	0- 3,500	\$250	7,001 - 12,000	\$ 750
	3,501 - 7,000	500	12,001 or below	1,000

 - b. Seismic drilling: \$100.
 - c. Recompletion: \$100 under special conditions.
 - d. Plugging and abandoning: No.

3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: Yes.
 - a. When is directional survey necessary? Before beginning the deviation.
 - b. Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required: Yes. Depends on the situation. Each well is handled separately according to the conditions that exist.
 - a. Surface casing: Yes.
 - b. Production casing: Yes.
2. Minimum amount of cement required:
 - a. Surface casing: TD to surface.
 - b. Production casing: From the shoe into surface casing.
 - c. Setting time: Yes. Not less than 16 hours.
3. Tubing requirements:
 - a. Oil wells: Yes.
 - b. Gas wells: Yes.

Completion

1. Completion report required: Yes.
 - a. Time limit: 30 days.
 - b. Where submitted: Department of Natural Resources, Division of Geology and Earth Resources, P O Box 47007, Olympia WA 98504-7007.
2. Well logs required to be filed: Yes.
 - a. Time limit: Thirty days for descriptive logs, 6 months for downhole surveys.
 - b. Where submitted: Division of Geology and Earth Resources.
 - c. Confidential time period: Yes. Twelve months from day of filing.
 - d. Available for public use: Yes.
 - e. Log catalog available: No. Information Circular 75 indicates what well logs are available.
3. Multiple completion regulation: Yes.
 - a. Approval obtained: Department action.
4. Commingling in well bore: Yes.
 - a. Approval obtained: Department action.

Oil Production

1. Definition of an oil well: No legal definition.
2. Potential tests required: No.
 - a. Time interval: On a case by case basis.
 - b. Witness required: Yes.
3. Statewide allowable: All allowables would be set by the Department on a pool by pool basis.
 - a. Pool allowable:
 - b. Well allowable:
 - c. Exempt allowable:

4. Maximum gas-oil ratio: Yes.
 - a. Provision for limiting gas-oil ratio: Yes.
 - b. Exception to limiting gas-oil ratio: Yes.
5. Bottom-hole pressure test reports required: No.
 - a. Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: Yes, with written permission from the Supervisor.
7. Measurement involving meters: No.
8. Production reports: Yes.
 - a. By lease:
 - b. By well: Yes.
 - c. Time limit: 30 days.

Gas Production

1. Definition of a gas well: No legal definition.
2. Pressure base _____ psia @ _____ degrees F.
3. Initial potential tests: Yes.
 - a. Time interval: 24 hours.
 - b. Witness required: Yes.
4. Statewide allowable: Yes. All allowables would be set by the Department on a pool by pool basis.
 - a. Pool allowable:
 - b. Well allowable:
 - c. Exempt allowable:
5. Bottom-hole pressure test reports required: No.
 - a. Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: Yes, with written permission from the Supervisor.
7. Measurement involving meters: Yes.
8. Production reports: Yes.
 - a. By lease: Yes.
 - b. By well: Yes.
 - c. Time limit: 30 days.

Water Disposal

1. State agencies that control disposal of produced salt water: Department of Ecology.

Unitization

2. Compulsory unitization of all or part of a pool or common source of supply: Yes, but only for secondary recovery.
3. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - a. Working interest: As determined by the Department.
 - b. Royalty interest: As determined by the Department.

Taxation

There is no state tax levied on oil and gas in Washington at this time.

Land Leasing Information

1. Leasing Method: Sealed-bid auction. No over the counter sales of state oil and gas leases.
2. Notice Method: Advertised in the Olympia paper, and the official notice of Auction is distributed to oil and gas community mailing list.
3. Application Process: A \$25 application fee and a bid deposit of \$150 per parcel must accompany each application for lease. The bid deposit will be refunded if the applicant is not the successful bidder. If the applicant is the successful bidder, the deposit will go toward the first year's annual rental (\$1.25/acre). The bid deposit will be forfeited if the successful bidder fails to execute the lease.
4. Minimum bidding: The successful bidder will be determined by the highest bonus bid offered for each parcel. The starting bonus bid will be \$2.00/acre. A \$1.00/acre surcharge will also be assessed to the successful bidder to cover the costs of associated environmental reviews and lease processing.
5. Qualification of the bidder: Anyone can submit a sealed-bid.
6. State Statutes:
 Chapter 79.14 Revised Code of Washington (RCW)
 Available at <http://slc.leg.wa.gov>
 Chapter 332.12 Washington Administrative Code (WAC)
 Available at <http://slc.leg.wa.gov>
7. Maximum acres: 640 acres or one government-surveyed section (some parcels in this category exceed 1,000 acres).
8. Contact: Bob Suda, Product Sales and Leasing Division
 Washington Department of Natural Resources
 P.O. Box 47016
 Olympia, WA 98504-47016
 Phone: 360.902.1642
 E-mail: bob.suda@wadnr.gov
 Web site: www.dnr.wa.gov

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Department of Health, Division of Radiation Protection, P.O. Box 47827, Olympia, WA 98504-7827. Phone: (360) 753-3459, Fax: (360) 753-1496.
2. Relevant Statute/Regulations: No specific NORM regulations.
3. Scope: WAC 246-221-001 establishes standards for protection against radiation hazardous including Radium-226.
4. Licensing: WAC 246-232-120 lists the amount of Radium-226 that is exempt from licensing.
5. Cleaning Equipment: WAC 246-232-140 Schedule D lists acceptable surface contamination levels for alpha, beta and gamma.
6. Disposal of Waste: 246-249-080 Large volumes of NORM (acceptance criteria).
7. Subsequent Use of Equipment: Same as 246-232-1.40.
8. Subsequent Use of Materials: Same as 246-232-120.
9. Release/Sale of NORM-Contaminated Land: 246-235 Specific License criteria.

10. Projected Volume of stored NORM in the State: Not determined.
11. Respondent: Gary Robertson

WEST VIRGINIA

Administration

1. State agency: West Virginia Oil and Gas Conservation Commission and Department of Environmental Protection, Office of Oil and Gas, both located at 601 57th St., Charleston, WV 25304. Phone (304) 926-0450, Fax (304) 926-0452.
2. Docketing procedure: (a) Monthly meeting of Commission, (b) Hearing upon application not less than 20 days nor more than 45 days following receipt, time and location of hearing specified in notice; proposed order 30 days following hearing; opportunity to comment 15 days following proposed order; thereafter issue order as appropriate.
 - (a) Emergency orders: Yes.
 - (b) Notice: 10 days. Certified mail to well operators and pertinent coal operators, and regular mail to all parties requesting receipt of notice.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: Bond is for the life of the well and plugging and reclamation.
 - (a) Amount per well: \$5,000.
 - (b) Amount of blanket bond: \$50,000.

Spacing

1. Spacing requirements: General rule: deep wells, 3,000' from wells producing from same formation and 400' from lease line; shallow wells, none; Coalbed methane wells, 1600' without consent from coal owner/operator between wells and 100' from lease line.
 - (a) Density: Maximum - 640 acres for gas wells and 160 acres for oil wells in a unit.
 - (b) Lineal: Deep wells only 3,000' from wells producing from the same formation except by special field rules; none for shallow wells for gas or oil.
2. Exceptions: Yes.
 - (a) Basis: Economic, geological or topographic or reservoir necessity.
 - (b) Approval: By application, hearing and order.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes, Oil and Gas Conservation Commission, CBM wells and the Coalbed Methane Review Board. Deep wells in primary production; all wells in enhanced recovery.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes, by the Department of Environmental Protection, Office of Oil and

- Gas.
 - (b) Seismic drilling: No.
 - (c) Recompletion: Yes.
 - (d) Plugging and abandoning: Yes.
- 2. Permit fee:
 - (a) Drilling: \$650.
 - (b) Fracture: \$650.
 - (c) Seismic drilling: NA.
 - (d) Recompletion: \$650 - well work permit fee.
 - (e) Plugging and abandoning: \$100 per pit registration; no discharge, no fee.
- 3. Require filing report of work performed: Yes.

Vertical Deviation

- 1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? Deep wells.
 - (b) Filing of survey required? Yes, if performed (for instance, directional drilling).

Casing and Tubing

- 1. Minimum amount required: Protect coal.
 - (a) Surface casing: Protect fresh water.
 - (b) Production casing: Yes.
- 2. Minimum amount of cement required:
 - (a) Surface casing: To surface.
 - (b) Coal casing: 30 feet below deepest coal seam to surface.
 - (c) Production casing: Adequate for separation of producing zones and high pressure zones.
 - (d) Setting time: Yes. Minimum of 8 hours and 500 lb. compression strength.
- 3. Tubing requirements:
 - (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

- 1. Completion report required: Yes.

- (a) Time limit: 90 days.
 - (b) Where submitted: Department of Environmental Protection, Office of Oil and Gas.
2. Well logs required to be filed: Deep wells only.
- (a) Time limit: 90 days.
 - (b) Where submitted: Oil and Gas Conservation Commission.
 - (c) Confidential time period: Yes. One year, additionally to three total years for good cause.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: Yes.
3. Multiple completion regulation: Yes, deep wells.
- (a) Approval obtained: Justification at hearing.
4. Commingling in well bore: Yes.
- (a) Approval obtained: Justification at hearing.

Oil Production

- 1. Definition of an oil well: "Oil Well" shall mean any well which produces less than 6,000 cubic feet of gas to each barrel of oil on the basis of initial gas-oil ratio test, defining oil and gas as in the Statute.
- 2. Potential tests required: GOR.
 - (a) Time interval: 24 hour minimum.
 - (b) Witness required: No.
- 3. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: Yes, in special deep well circumstances.
 - (c) Exempt allowable: No.
- 4. Maximum gas-oil ratio: Less than 6,000 cubic feet of gas to one barrel of oil.
 - (a) Provision for limiting gas-oil ratio: No.
 - (b) Exception to limiting gas-oil ratio: No.
- 5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
- 6. Commingling oil in common facilities: No.
- 7. Measurement involving meters: No.

8. Production reports:
 - (a) By lease: Yes, for secondary recovery fields; otherwise, no.
 - (b) By well: Yes.
 - (c) Time limit: Annually before March 31 of following year.

Gas Production

1. Definition of a gas well: "Gas Well" shall mean any well which produces 6,000 cubic feet or more of gas to each barrel of oil on the basis of the initial gas-oil ratio test, defining oil and gas in the Statute.
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes.
 - (a) Time interval: Not less than 24 hours.
 - (b) Witness required: No.
4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: Yes, in special deep well circumstances.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: No.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: No.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: Yes, for secondary recovery fields; otherwise, no.
 - (b) By well: Yes, MCF.
 - (c) Time limit: Annually before March 31 of following year.

Water Disposal

1. State agencies that control disposal of produced salt water: Department of Environmental Protection, Division of Water and Waste Management.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:

- (a) Working interest: None for primary, 75% for enhanced.
- (b) Royalty interest: None for primary, 75% for enhanced.

Taxation

Gas severance tax = 5.0%
 Gas ad valorem tax = 0.0%
 Total gas tax burden = 5.0%

Oil severance tax = 5.0%
 Oil ad valorem tax = 0.0%
 Total oil tax burden = 5.0%

1. Tax collecting agency: State Tax Department, P. O. Drawer 1826, Charleston, WV 25327.
2. How tax is computed: Gross value: The gross value is the value of the natural gas or oil produced, as shown by the gross proceeds derived from the sale thereof by the producer - 5.0%.
3. Exemptions or exceptions: Removal of natural gas from underground storage facilities into which the natural gas has been mechanically injected following its initial removal from the earth. Any separation process of oil or natural gas commonly employed to obtain marketable natural resource produced is exempt from taxation. (But see, WV Code §11-13-2e, Gas Storage Tax).

The following are excluded from severance tax as of 1/1/2000:

- (a) Natural gas provided to the surface rights owner.
 - (b) Wells that have an average daily production of the immediately preceding year is less than five thousand cubic feet.
 - (c) Oil wells that have an average daily production for the immediately preceding calendar year of less than one-half barrel of oil.
 - (d) Wells that have not produced marketable quantities of natural gas or oil for five consecutive years immediately preceding the year in which a well is placed back into production and thereafter produces marketable quantities of natural gas or oil, severance tax is not levied for a maximum period of ten years from that point.
4. Name of tax: Severance Tax.
 5. Statutory citation: WV Code §11-13A-3a.

Land Leasing Information

There are no regulations at this time.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Bureau for Public Health.
2. Relevant State/Regulations:
3. Scope: Regulations cover radioactive materials but not specific to NORM.
4. Licensing: Does not license.

5. Cleaning Equipment:
6. Disposal of Waste:
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of Stored NORM in the State:
11. Respondent: Beattie DeBord

WYOMING

Administration

1. State agency: Wyoming Oil and Gas Conservation Commission, P. O. Box 2640, Casper, WY 82602. Phone (307) 234-7147.
2. Docketing procedure: Oil and gas hearings are scheduled a year in advance, generally on the second Tuesday of each month. Applications are accepted and heard monthly and orders issued within 30 days. S.S. 30-219.2.
 - (a) Emergency orders: Emergency orders can be issued without notice and hearing. A regular hearing with notice must be held within 15 days. S.S. 30-223 (c).
 - (b) Notice: Notice of hearings given by the Commission at least 10 days prior to the date of the hearing; 30 days on rule changes and on applications for aquifer exemptions. Chapter IV, Section 12. The Commission gives notice in all applications. Occasionally the applicant duplicates the notice. S.S. 30-223 (b) and (d).

Bond

1. Compliance bond required: Yes.
2. Seismic bonds. Chapter IV, Section 6. Client company - \$50,000; Geophysical contractors - \$50,000; Seismic hole plugger's - \$10,000.
3. Drilling, operating, plugging, and restoration bonds for fee lands:
 - (a) Bonds for wells less than 2,000 feet in depth. Chapter III, Section 4 - \$10,000 individual bond, \$75,000 blanket bond.
 - (b) Bonds for wells deeper than 2,000 feet. Chapter III, Section 4 - \$20,000 individual bond, \$75,000 blanket bond.
 - (c) Additional bonding up to \$3.00 per foot for idle wells in excess of 8,300' or 25,000' depending on level of blanket bond in place. Chapter III, Section 4.
 - (d) Bonding options:
 - (1) Owner's surety bond. Chapter III, Section 4 - \$10,000 or \$20,000 as applicable.
 - (2) Owner's blanket bond. Chapter III, Section 4 - \$75,000.
 - (3) Letter of Credit. Chapter III, Section 6.
 - (4) Certificate of deposit. Chapter III, Section 5.
 - (5) Cash (cashier's check). Chapter III, Section 5.
4. Drilling, operating, plugging, and restoration bonds for state lands (Bond of Lessee). Bond of Lessee is provided to the Commissioner of Public Lands - \$10,000 individual bond, \$100,000 blanket bond, with the same bonding options as available for fee lands.
5. Split Estates Bond: Statute § 30-5-404. Surety bond or guaranty; approval; objections; release of surety bond or guaranty.
 - a. The surety bond or other guaranty shall be in an amount of not less than two thousand dollars (\$2,000.00) per well site on the land. At the request of the oil and gas operator, after attempted consultation with the surface owner the commission may establish a blanket bond or other guaranty in an amount covering oil and gas operations on the surface owner's land as identified by an oil and gas operator in the written notice required under W.S. 30-5-402(e). Neither the minimum amount of the per well site bond or other guaranty by the commission is intended to establish any amount for reasonable and foreseeable damages.

- b. WOGCC Rule, Chapter 3, Section 4(i): Provides the minimum amount of bond and the forms of surety which may be accepted by the Commission in satisfaction of the requirements contained within the Wyoming Split Estates Act. It also provides that a field wide bond may be posted. This change is required to implement the Wyoming Split Estates Act.

Spacing

1. Spacing requirements: Yes.
 - (a) Density: 40 acres for an oil well; 40, 160 and 640 acres for a gas well; 40 and 80 acres for a coalbed methane well.
 - (b) Lineal: For an oil well, not closer than 460 feet to the exterior boundaries of a 40-acre subdivision. Same for a gas well or a coalbed methane well, center of NE/4 or SW/4 with 200 feet of tolerance on 40 acres, and the center of a 160-acre tract with 200 feet of tolerance. Chapter III, Section 2.
 - (c) Horizontal wells, no closer than 660' to unit boundary or 1320' from any vertical well completed in the same zone. Temporary 640 acre spacing. Certain areas have alternate spacing patterns. Requires notice in one half (1/2) mile area.
2. Exceptions: Yes.
 - (a) Basis: Geologic or topographic.
 - (b) Approval: Administratively in the absence of any objection; by Commission order should there be an objection. Chapter III, Section 3 and Chapter V, Section 16.

Pooling

1. Authority to establish voluntary: Yes. S.S. 30-221 (f) and (g).
2. Authority to establish compulsory: Yes.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes. Chapter III, Section 8.
 - (b) Seismic drilling: Yes. Chapter IV, Section 6.
 - (c) Stratigraphic or Core Hole: Yes. Chapter III, Section 9.
 - (d) Deepening an existing well: Yes. Chapter III, Section 8.
 - (e) Plugging and abandoning: Yes. Chapter III, Section 18.
 - (f) Reserve and workover pits: Yes. Chapter IV, Section 1.
2. Permit fee:
 - (a) Drilling: \$50.00 drilling permit. Good for one year.
 - (b) Seismic and stratigraphic/corehole drilling: \$50.00 drilling permit.

- (c) Recompletion: \$50.00 if deeper.
 - (d) Workovers, plugging and abandoning: None.
 - (e) Injection well and disposal well annual fee \$75.00.
3. Require filing report of work performed: Yes. Form No. 4, for wells and pits and Seismic Completion Report for seismic lines.

Vertical Deviation

1. Regulation requirement: Yes. Chapter III, Section 24 and 25.
- (a) Directional survey required? Yes.
 - (b) Filing of survey required? Yes, within 30 days after completion.
 - (c) Directional drilling approval valid for one year.

Casing and Tubing

1. Minimum amount required:
- (a) Surface casing: Yes.
 - (b) Production casing: Yes.
 - (c) Wells drilled within the special sodium drilling area: Yes.
2. Minimum amount of cement required:
- (a) Surface casing: Yes.
 - (b) Production casing: Yes.
 - (c) Wells drilled within the special sodium drilling area: Yes.
 - (d) Setting time: Yes, eight hours.
3. Tubing requirements: See Chapter III, Section 22, General Drilling Rules.
- (a) Oil wells: Yes.
 - (b) Gas wells: Yes.

Completion

1. Completion report required: Yes.
- (a) Time limit: Within 30 days after completion.
 - (b) Where submitted: To the Oil and Gas Conservation Commission.
2. Well logs required to be filed: Yes.
- (a) Time limit: Within 30 days after logs are run or within 30 days after completion of any further operation on it, if such operations involve drilling or redrilling. If requested, a 30-day extension to the filing due date may be

granted.

- (b) Where submitted: The Oil and Gas Conservation Commission. Chapter III, Section 21, Filing of Well Logs.
 - (c) Confidential time period: Yes, if requested, for six months.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes. Chapter III, Section 35.
 - (a) Approval obtained: Administratively, in the absence of any objection; otherwise by Commission order.
 4. Commingling in well bore: Yes. Chapter III, Section 35.
 - (a) Approval obtained: Administratively in the absence of any objection; otherwise by Commission order.

Oil Production

1. Definition of an oil well: Oil well shall mean a well the principal production of which, at the mouth of the well, is oil, as defined by the Wyoming Conservation Law. Chapter I, Section 2(ff).
2. Potential tests required: Yes. Form 3.
 - (a) Time interval: Within 30 days.
 - (b) Witness required: Yes, by the operator; occasionally by the Commission.
3. Statewide allowable: No.
 - (a) Pool allowable: Occasionally in order to preserve reservoir pressure and obtain the maximum amount of recovery.
 - (b) Well allowable: Yes, after notice and hearing by statute, the production from an exception location can be curtailed.
 - (c) Exempt allowable: No.
4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Occasionally. Only after notice and hearing in order to prevent subsurface waste and maintain the maximum reservoir pressure.
 - (b) Exception to limiting gas-oil ratio: Yes.
5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: They can be. Chapter III, Section 36.
6. Commingling oil in common facilities: Approved administratively on application. Adequate metering or measuring of oil must be assured.
7. Measurement involving meters: No.
8. Production reports:

- (a) By lease: No.
- (b) By well: Yes.
- (c) Time limit: 30 days after production.

Gas Production

1. Definition of a gas well: Gas well shall mean a well the principal production of which, at the mouth of the well, is gas, as defined by the Wyoming Conservation Law. Chapter I, Section 2(u).
2. Pressure base 14.73 psia @ 60 degrees F.
3. Initial potential tests: Yes. Form 3 and 10 through 13.
 - (a) Time interval: When necessary.
 - (b) Witness required: Supervisor's discretion.
4. Statewide allowable: No.
 - (a) Pool allowable: Occasionally, in order to maintain reservoir pressure.
 - (b) Well allowable: Yes, in order to maintain reservoir pressure or prevent waste.
 - (c) Exempt allowable: No.
5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: They can be.
6. Commingling of gas in common facilities: Considered administratively on application. Adequate measuring and testing must be assured.
7. Measurement involving meters: No.
8. Production reports:
 - (a) By lease: No.
 - (b) By well: Yes.
 - (c) Time limit: 30 days after production.

Water Disposal

1. State agencies that control disposal of produced salt water: The Wyoming Oil and Gas Conservation Commission regulates underground disposal and single lease evaporation pits. Chapter IV, Sections 1 and 5. The Department of Environmental Quality regulates the surface discharge of oil field water.

Unitization

1. Compulsory unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:

- (a) Working interest: 80%.
- (b) Royalty interest: 80%.

At the least, the above minimum percentage can be reduced by the Commission to 75%, providing that unitization negotiations have been underway for nine months or longer between the parties involved.

Taxation

Gas severance tax = 6.0%
 Gas ad valorem tax = 5.9% to 7.7%
 Total gas tax burden = 11.9% to 13.7%

Oil severance tax = 6.0%
 Oil stripper well tax = 4.0%
 Oil ad valorem tax = 5.9% to 7.7%
 Total oil tax burden = 9.9% to 13.7%

1. Tax collecting agency: Department of Revenue and Taxation, 122 W. 25th Street, Cheyenne, WY 82002; County Assessors' offices; Oil and Gas Conservation Commission.
2. How tax is computed: Severance tax - 6.0% for oil and gas; 4.0% for oil stripper well. Administration of stripper well now allows an operator to count the injection wells and producing wells in determining daily lease totals. Ad Valorem tax - an average of 5.9 to 7.7%, depending on the school district where the production is located. Conservation tax - a maximum of .0008 of a mill, Chapter III, Section 44. The current conservation tax mill levy is .0002 of a mill.
3. Exemptions or exceptions:
 - (a) Oil produced from wells that have been shut in for two years will have severance tax reduced to one and one half (1.5) for 5 years. This is effective January 1, 1995 with no sunset.
 - (b) Natural gas which is vented or flared under the authority of the Wyoming Oil and Gas Conservation Commission and natural gas which is consumed or reinjected prior to sale for the purpose of maintaining, stimulating, processing, transporting or producing crude oil or natural gas on the same lease or unit from which it was produced has no value and is exempt from taxation.
4. Name of tax: Severance, Conservation Tax.
5. Statutory citation: Wyoming Statutes (republished) Sections 39-6-302, 39-6-303.

Land Leasing Information

1. Leasing Method: Public Auction - no sealed bids sale; open oral bid - if no bid is received - offer the lease over the counter at 1st come 1st served basis.
2. Notice Method: Advertise the sale in the newspapers in the Rocky Mountain area.
3. Minimum bidding \$ (per acre): \$1.00/acre bonus.
4. Qualification of the bidder: A U.S. Citizen, 19 years of age minimum, and as a corporation, qualified by the Secretary of State to do business in Wyoming.
5. State Statutes: WY ST § 36-6-101 and General Chapter 6 Rules of the Board of Land Commissioners.
6. Maximum acres: 640 acres.

7. Contact: Harold D. Kemp
Hkemp@missc.state.wy.us
Phone: (307) 777-7331

Note: Wyoming holds 4 sales per year, always on the day after the federal oil and gas lease auction in Cheyenne.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Wyoming Oil and Gas Conservation Commission, P.O. Box 2640, Casper, WY 82602. Phone: (307) 234-7147.
2. Relevant Statute/Regulations: Rule 404(J.).
3. Scope:
4. Licensing:
5. Cleaning Equipment:
6. Disposal of Waste: Rule 404(J.) - Dispose of produced water, tank bottoms and other miscellaneous solid waste in a manner which is in compliance with the Commission's rules and other state, federal, or local regulations.
7. Subsequent Use of Equipment:
8. Subsequent Use of Materials:
9. Release/Sale of NORM-Contaminated Land:
10. Projected Volume of stored NORM in the State:
11. Respondent: Janie Nelson
12. Regulating Agency: Department of Environmental Quality, Water Quality Division, 122 W. 25th St., Herschler Bldg., 4W, Cheyenne, WY 82001. Phone: (307) 777-7082.
13. Relevant Statute/Regulations: Chapter 1, Section 22, Water Quality Rules and Regulations. Applied to NPDES permits.
14. Scope: Class 1 and 2 waters not to exceed radiological limits established on the most recent Federal Primary Drinking Water standards published by EPA. Class 3 and 4 waters radium-226 concentration shall not exceed 60pci/l.
15. Licensing: NPDES individual permit.
16. Cleaning Equipment:
17. Disposal of Waste:
18. Subsequent Use of Equipment:
19. Subsequent Use of Materials:
20. Release/Sale of NORM-Contaminated Land:
21. Projected Volume of stored NORM in the State:

22. Respondent: Maggie Davison

ALBERTA

Administration

1. Provincial agency: Alberta Energy and Utilities Board, 640-5th Avenue SW, Calgary, AB T2P 3G4, Telephone: (403) 297-8311, Fax: (403) 297-7336

The Alberta Energy and Utilities Board (EUB) is an independent, quasi-judicial agency of the Government of Alberta with responsibility to regulate Alberta's energy resources and utility sectors. Although the EUB is responsible to the Alberta Minister of Energy, it makes its formal decisions independently and in accordance with the various Acts and Regulations.

The EUB is responsible for the policy and direct administration of the following statutes: *Alberta Energy and Utilities Board Act, Coal Conservation Act, Energy Resources Conservation Act, Hydro and Electric Energy Act, Gas Resources Preservation Act, Oil and Gas Conservation Act, Oil Sands Conservation Act, Pipeline Act, Public Utilities Board Act, Turner Valley Unit Operations Act* with consequential regulations. The Board has rate regulation responsibilities under the *Electric Utilities Act*, the *Gas Utilities Act* and other legislation that specifically empowers the Board to carry out certain functions.

2. Docketing procedure: The Board determines whether a particular application should be set down for a hearing based on submissions from potentially affected parties.
 - (a) Emergency orders: The EUB has emergency powers to protect public safety and the environment pursuant to its legislation.
 - (b) Notice: Notice of Proceeding is issued, pursuant to the Alberta Energy and Utilities Board Rules of Practice (AR 101/2001).

Administrative Fees and General Assessment

The EUB is funded through a government grant and an administrative fee imposed on the industry. The administrative fee, collected from each sector regulated by the EUB, reflects the EUB's estimated operating costs associated with regulating that sector (*Alberta Energy and Utilities Board Act, Public Utilities Board Act* and the *Oil and Gas Conservation Act*).

The legislation authorizing the EUB to levy the administrative fee in the oil and gas, oil sands, electric generation, and coal sectors provides for the application of a late-payment penalty of 20 percent on any portion of the fee that remains unpaid after the deadline date. In the case of a failure to pay an invoice or late-payment penalty, the EUB can initiate action to close producing facilities. Late-payment penalties for the utilities sector will apply as stipulated in the Public Utilities Board Act.

Oil and gas and oil sands invoices for administrative fees are sent to and payable by the operator. For conventional wells and oil sands schemes, "operator" means the company that files well production and/or injection/disposal data with the Petroleum Registry. If the operator fails to pay the fee, the licensee is responsible for payment of the invoiced amount plus any penalty.

Spacing

1. Spacing requirements: Part 4 "Drilling Spacing Units and Target Areas" Oil and Gas Conservation Regulations (AR 151/71).
 - (a) Density: gas well- 1 well per section per pool, unless otherwise authorized by the Board.
 - (b) oil well- 1 well per quarter section per pool, unless otherwise authorized by the Board.
 - (c) Special rules for specified area of province and for specified zones- density: gas wells- 4 wells per section per pool for wells above the Manville Formation and 2 wells for wells producing from the Manville Formation

- Oil well- 2 wells per quarter section per pool for wells producing from the Manville Formation
- (d) Lineal: Interval distances dictated by target area provisions which are set out in section 4.030 and schedule 13.
- (e) Under special rules interval distances are set out in section 4.030 (2.1).

2. Exceptions:

- (a) Basis: The need for additional wells to improve recovery.
- (b) Approval: Issued by Spacing Unit Order.

Pooling

1. Authority to establish voluntary: Unitization- Section 79 of the *Oil and Gas Conservation Act*, RSA 2000 Chapter 0-6.
2. Authority to establish compulsory pooling: Well basis- Section 80 of the *Oil and Gas Conservation Act*, RSA 2000 Chapter 0-6.

Drilling Permit

1. Require permits for:

- (a) Drilling a producing or service well: Section 11 of the *Oil and Gas Conservation Act*, RSA 2000 Chapter 0-6 and Directive 56 “*Energy Development Applications and Schedules*” September 2005 version; Part 3 “*Licensing of Wells*” Oil and Gas Conservation Regulations (AR 151/71)
- (b) Seismic drilling: not applicable
- (c) Recompletion: section 3.010 of the Oil and Gas Conservation Regulations (AR 151/71)
- (c) Plugging and abandoning: Sections 3.012 and 3.013 of the Oil and Gas Conservation Regulations require the licensee to conduct abandonment, casing removal, zonal abandonment’s and plug backs in accordance with the current edition of the Alberta Energy and Utilities Board (EUB) *Directive 20: “Well Abandonment Guide”* (August 2003) Provides regulatory requirements for licensees abandoning wells in Alberta. Includes the minimum requirements for the licensees to follow for:
 - developing open and cased-hole abandonment programs
 - removing surface casing
 - performing remedial cementing
 - locating cement plugs
 - testing for surface casing vent flows and gas migration

2. Permit fee:

- (a) Drilling: not applicable
- (b) Seismic drilling: not applicable
- (c) Recompletion: not applicable

3. Require filing report of work performed: Directive 59 “*Well Drilling and Completion Data Filing Requirements*” 3rd edition May 2001 (Revised October 2002).

Vertical Deviation

1. Regulation requirement:
 - (a) When is directional survey necessary? When a deviation occurs from the vertical.
 - (b) Filing of survey required? Yes, pursuant to Section 6.030 of the Oil and Gas Conservation Regulations (AR 151/71)

Casing and Tubing

1. Minimum amount required:
 - (a) Surface casing: Directive 8 “*Surface Casing Depth Minimum Requirements*” (October 1997) Outlines surface casing depth requirements in accordance with the Oil and Gas Conservation Regulations. Directive 10 “*Minimum Casing and Design Requirements*” (September 1990) Sets out casing design requirements according to S. 6.080 of the Oil and Gas Conservation Regulations.
 - (b) Production casing: Directive 10 “*Minimum Casing and Design Requirements*” (September 1990, under revision) sets out casing design requirements.
2. Minimum amount of cement required:
 - (a) Surface casing: Directive 9 “*Casing Cementing Minimum Requirements*” (July 1990) Outlines casing cementing requirements in accordance with the Oil and Gas Conservation Regulations.
 - (b) Production casing: Directive 9 “*Casing Cementing Minimum Requirements*” (July 1990) Outlines casing cementing requirements in accordance with the Oil and Gas Conservation Regulations. Directive 10 “*Minimum Casing and Design Requirements*” (September 1990, under revision). Sets out casing design requirements according to the Oil and Gas Conservation Regulations. Directive 51 “*Injection and Disposal Wells-Well Classifications, Completions, Logging and Testing Requirements*” (March 1994): Clarifies completion, logging testing, monitoring and application requirements for injection and disposal wells. This directive also specifies procedures and practices designed to protect the subsurface environment, including all usable groundwater and hydrocarbon-bearing zones.
 - (c) Setting time: Directive 9 “*Casing Cementing Minimum Requirements*” (July 1990) Outlines casing cementing requirements in accordance with the Oil and Gas Conservation Regulations.
3. Tubing requirements:
 - (a) Oil wells: Section 6.101 of the Oil and Gas Conservation Regulations AR (151/71).
 - (b) Gas wells: not applicable

Completion

1. Completion report required: Directive 59 “*Well Drilling and Completion Data Filing Requirements*” (June 2004). The directive contains information with respect to completing and filing operations information for the following:
 - drilling a new well
 - performing a workover
 - re-entering an existing well
 - initial completion of a new well
 - completion of a new zone

- abandoning a zone in a well

Directive 37: “*Service Rig Inspection Manual*” (February 2006) refers to requirements found in Directives, numerous Interim Directives and Informational Letters and Part 6 of the Oil and Gas Conservation Regulations (AR 151/71).

- (a) Time limit: 30 days
- (b) Where submitted: EUB: Submission is done electronically through DDS (Digital Data Submission)
2. Well logs required to be filed: Section 11.140 of the Oil and Gas Conservation Regulations (AR 151/71)
 - (a) Time limit: Within 30 days of finished drilling date
 - (b) Where submitted: Information Collection and Dissemination Group, EUB, Phone (403) 297-2581
 - (c) Confidential time period: 1 year- Section 12.150 of the Oil and Gas Conservation Regulations (AR 151/71).
 - (d) Available for public use: Yes, in both paper and electronic format but subject to confidentiality provisions.
 - (e) Log catalog available: Database entitled “Log Well Subsystem”
3. Multiple completion regulation: Sections 3.040, 3.050, 3.051 and 3.060 of the Oil and Gas Conservation Regulations (AR 151/71) and Part 15 “Certain applications” Oil and Gas Conservation Regulations (AR 151/71).
 - (a) Approval obtained: Section 3.050 of the Oil and Gas Conservation Regulations (AR 151/71).
4. Commingling in well bore: Sections 3.040, 3.050, 3.051 and 3.060 of the Oil and Gas Conservation Regulations (AR 151/71), Part 11 of the Oil and Gas Conservation Regulations (AR 151/71)- new commingling rules as of November 2006 & Directive 65 “*Resources Applications for Conventional Oil and Reservoirs*”. The resource applications for which this directive applies are divided into units as follows:
 - 1) Equity: ratable take, common purchaser, common carrier, common processor, compulsory pooling and special spacing.
 - 2) Conservation: enhanced recovery scheme (gas cycling, waterflood, immiscible gas flood, miscible flood), enhanced recovery project, enhanced recovery recognition and good production practice, concurrent production, and pool delineation and ultimate reserves.
 - 3) Production Control: commingled production, good production practice (primary depletion pools), gas-oil ratio penalty relief, special maximum rate limitation and gas allowable
 - 4) Disposal/Storage: disposal (water and waste), acid gas disposal, and underground gas storage
 - 5) Corporate Changes: change in the name of the holder of an EUB approval and change in holder of an EUB approval

- (a) Approval obtained: If needed- Commingling Order (MU Order)

Oil Production

1. Definition of an oil well: Oil and Gas Conservation Regulations (AR 151/71) section 1.020(2) (12)
2. Potential tests required: No testing required.
 - (a) Time interval: not applicable

- (b) Witness required: not applicable
- 3. Alberta allowable: Part 10 "Production Rates and Accounting" Oil and Gas Conservation Regulations (AR 151/71), Part 15 "Central Applications" Oil and Gas Conservation Regulations and Directive 65 "Resources Applications for Conventional Oil and Gas Reservoirs".
 - (a) Pool allowable: Maximum Rate Limitation (MRL) assigned at the pool level
 - (b) Well allowable: MRL is administered on a well basis
 - (c) Exempt allowable: Where a pool or well has been granted Good Production Practices (GPP) or Special MRL or GOR penalty relief.
- 4. Maximum gas-oil ratio: Part 10 "Production Rates and Accounting" Oil and Gas Conservation Regulations (AR 151/71), Part 15 "Central Applications" Oil and Gas Conservation Regulations and Directive 65 "Resources Applications for Conventional Oil and Gas Reservoirs" June 2000 (currently being revised).
 - (a) Provision for limiting gas-oil ratio: GOR penalties applied to oil wells not on GPP
 - (b) Exception to limiting gas-oil ratio: GPP or GOR penalty relief
- 5. Bottom-hole pressure test reports required:
 - (a) Periodical bottom-hole pressure surveys: Pressure Survey Schedule associated with Directive 40 "*Pressure ad Deliverability Testing Oil and Gas Wells-Minimum Requirements and Recommended Practices*"
- 6. Commingling oil in common facilities: Directive 7 "*Production Accounting Handbook*" (May 2001)
- 7. Measurement involving meters: Part 14 "Measurement" Oil and Gas Conservation Regulations (AR 151/71) and Directive 17 "*Measurement Requirements for Upstream Oil and Gas Operations*" (Released: February 1, 2005)
- 8. Production reports: Part 12 "Records and Reports" Oil and Gas Conservation Regulations (AR 151/71) and Directive 7 "Production Accounting Handbook"
 - (a) By lease: not applicable
 - (b) By well: Electronic submission to the Petroleum Registry of Alberta
 - (c) Time limit: Monthly

Gas Production

- 1. Definition of a gas well: Oil and Gas Conservation Regulations (AR 151/71), section 1.020(2) (8).
- 2. Pressure base 101.325 Kpa @ 15 degrees C.
- 3. Initial potential tests: Section 11.102 of the Oil and Gas Conservation Regulations (AR 151/71) and in accordance with Directive 40 "*Pressure ad Deliverability Testing Oil and Gas Wells-Minimum Requirements and Recommended Practices*" (3rd edition 1999) Comprehensive guide designed as a handbook on oil and gas well testing.
 - (a) Time interval: Refer to Directive 40.
 - (b) Witness required: not applicable
- 4. Provincial allowable:

- (a) Pool allowable: Section 10.300 of the Oil and Gas Conservation Regulations (AR 151/71) and Directive 65 "Resources Applications for Conventional Oil and Gas Reservoirs".
 - (b) Well allowable: Section 10.300 of the Oil and Gas Conservation Regulations (AR 151/71) and Directive 65 "Resources Applications for Conventional Oil and Gas Reservoirs" June 2000 (currently being revised).
 - (c) Exempt allowable: Gas wells are typically exempt from allowables unless off-target.
5. Bottom-hole pressure test reports required:
- (a) Periodical bottom-hole pressure surveys: Pressure Survey Schedule associated with Directive 40 "*Pressure and Deliverability Testing Oil and Gas Wells-Minimum Requirements and Recommended Practices*" (May 2004).
6. Commingling of gas in common facilities: Directive 7 "*Production Accounting Handbook*" (May 2001).
7. Measurement involving meters: Part 14 "Measurement" Oil and Gas Conservation Regulations (AR 151/71) and Directive 17 "*Measurement Requirements for Upstream Oil and Gas Operations*" (Released: February 1, 2005)
8. Production reports: Part 12 "Records and Reports" Oil and Gas Conservation Regulations (AR 151/71)
- (a) By lease: not applicable
 - (b) By well: Electric submission to the Petroleum Registry of Alberta
 - (f) Time limits: monthly

Underground Injection

1. Provincial agencies that control the underground injection of fluids: Alberta Environment and the EUB: For the EUB, please refer to Directive 51 "*Injection and Disposal Wells-Well Classifications, Completions, Logging and Testing Requirements*," (March 1994): Clarifies completion, logging, testing, monitoring and application requirements for injection and disposal wells. Specifies procedures and practices designed to protect the subsurface environment, including all usable groundwater and hydrocarbon-bearing zones and Directive 65 "*Resources Applications for Conventional Oil and Gas Reservoirs*" June 2000.

Unitization

1. Compulsory unitization of all or part of a pool or common sources of supply: No compulsory utilization.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: not applicable
 - (b) Royalty interest: not applicable

Taxation

Gas severance tax = 0%
 Gas ad valorem tax = 0%
 Gas Royalty= 5% to 35%
 Total gas tax burden = 5% to 35%

Oil severance tax = 0%
 Oil ad valorem tax = 0%

Oil Royalty= 0% to 40%
Total oil tax burden = 0% to 40%

1. Tax collecting agency: Alberta Energy
9945-108 Street, 7th Floor
Edmonton, Alberta
T5K 2G6
Tel: (780) 427-7425
Fax: (780) 422-8731
2. How tax is computed: Gas royalty rate is dependent on well productivity, gas price and pool discovery date. Oil royalty rate is dependent on well productivity, oil price, oil density and pool discovery date. Please visit website at www.energy.gov.ab.ca for specific formulas to calculate royalty rates.
3. Exemptions or exceptions: Otherwise Flared Solution Gas Royalty Waiver Program
Sulphur Emission Control Assistance Program
CO2 Projects Royalty Credit Program
Third Tier Exploration Oil Royalty Holiday Program
Horizontal Re-entry Oil Royalty Reduction Program (being phased out)
Enhanced Oil Recovery Royalty Relief Program
Experimental Conventional Oil Projects Program
Reactivated Oil Well Holiday Program
Low Productivity Oil Well Program
Innovative Energy Technologies Program
4. Name of tax: Crown royalty on crude oil and natural gas production.
5. Statutory citation: Natural Gas Royalty Regulation, 2002 (AR 220/2002).
Petroleum Royalty Regulation (AR 248/1990).

Land Leasing Information

1. Leasing Method: Public posting with sealed bid system. As of June 28, 2006 all bid submissions must be made through the Electronic Transfer System.
2. Notice Method: Determined by policy and set out in Information Letters
3. Minimum bidding \$ (per acre): \$1.00 per acre for a lease and \$0.50 per acre for a license.
4. Qualification of the bidder: Companies must be registered to conduct business in Alberta. Individuals and companies must be registered as Alberta Energy clients. Bidding clients require an Electronic Transfer System account and must be set up for electronic funds transfer.
5. Provincial Statutes: Mines and Minerals Act (M-17 RSA 2000)
Mines and Minerals Administration Regulation (AR 262/1997)
Petroleum and Natural Gas Tenure Regulation (AR 263/1997)
Crown Mineral Registration Regulation (AR 264/1997)
6. Maximum acres: 9,600 acres in the Plains Region (15 sections)
20,480 acres in the Northern Region (32 sections)
23,040 acres in the Foothills Region (36 sections)
7. Contact: Retha Purkis, Manager of P&NG Agreement Sales at (780) 422-9426 or Retha.Purkis@gov.ab.ca

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: The EUB, together with the stakeholders, is in the process of developing specific NORM requirements. Until such time as these requirements are developed, the EUB recommends that any handling, treating or disposal of NORM material generally follow the guidelines established by the NORM Committee document. Copies of the NORM guidelines may be obtained from:
 Alberta Human Resources and Employment
 9th Floor 10808 - 99th Avenue
 Edmonton, Alberta, Canada T5K 0G5
 Telephone: (780) 415-0612, Fax: (780) 427-5698
2. Relevant Statute/Regulations: not applicable
3. Scope: not applicable
4. Licensing: not applicable
5. Cleaning Equipment: not applicable
6. Disposal of Waste: not applicable
7. Subsequent Use of Equipment: not applicable
8. Subsequent Use of Materials: not applicable
9. Release/Sale of NORM-Contaminated Land: not applicable
10. Projected Volume of stored NORM in the State: not applicable
11. Respondent: not applicable

NEWFOUNDLAND AND LABRADOR ONSHORE

Administration

1. State agency: Department of Natural Resources, Government of Newfoundland and Labrador, P. O. Box 8700, St. John's, Newfoundland, Canada A1B 4J6. Phone: (709) 729-2920; Fax (709) 729-0059.
2. Docketing procedure: N/A
 - (a) Emergency orders:
 - (b) Notice:

Bond

1. Compliance bond required: *Petroleum Drilling Regulations*, Section 14(a) and 14(b)
2. Conditions of bond:
 - (a) Amount per well: Determined on well by well basis; irrevocable Letter of Credit or cash deposit.
 - (b) Amount of blanket bond: Cdn. \$10 million operators extra expense insurance

Spacing

1. Spacing requirements: Not applicable; based on approved development plan.
 - (a) Density: Not applicable; based on approved development plan.
 - (b) Lineal: Not applicable; based on approved development plan.
2. Exceptions: Under review. (Current practice does not involve spacing units).
 - (a) Basis: Under review.
 - (b) Approval: Under review.

Pooling

1. Authority to establish voluntary: *Petroleum Regulations*. As per approved development plan
2. Authority to establish compulsory: N/A

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: *Petroleum Drilling Regulations* – Drilling Program approval; Authority to Drill a Well. *Petroleum Regulations* “Permittee has right to....drill and test for petroleum”.
 - (b) Seismic drilling: *Exploration Survey Regulations*
 - (c) Recompletion: *Petroleum Drilling Regulations*

- (d) Plugging and abandoning: *Petroleum Drilling Regulations*
- 2. Permit fee:
 - (a) Drilling: \$1000 issuance fee for Exploration Permit.
 - (b) Seismic drilling: \$100 per seismic exploration survey licence.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.

- 3. Require filing report of work performed: Yes.

Vertical Deviation

- 1. Regulation requirement:
 - (a) When is directional survey necessary? During the drilling of a well at intervals not exceeding 150 m.
 - (b) Filing of survey required? Yes.

Casing and Tubing

- 1. Minimum amount required:
 - (a) Surface casing: Not less than 150 m.
 - (b) Production casing: At least 25% of the hole is cased during all drilling operations.
- 2. Minimum amount of cement required:
 - (a) Surface casing: 30% greater than the estimated annular volume or if estimate is based on a reliable caliper log, at least 10% greater than estimated annular volume.
 - (b) Production casing: 30% greater than the estimated annular volume or if estimate is based on a reliable caliper log, at least 10% greater than estimated annular volume.
 - (c) Setting time: In no case less than 6 hours; 12 hours minimum unless acceptable testing shows compressive strength of at least 3500 kilopascals.
- 3. Tubing requirements:
 - (a) Oil wells: Regulations being developed.
 - (b) Gas wells: Regulations being developed.

Completion

- 1. Completion report required:
 - (a) Time limit: Within 21 days of the rig release date in respect of the well.
 - (b) Where submitted: Dept. of Natural Resources, Petroleum Resource Development Division.
- 2. Well logs required to be filed:

- (a) Time limit: Submit by the most rapid and practical means.
 - (b) Where submitted: Department of Natural Resources, Petroleum Resource Development Division.
 - (c) Confidential time period: 2 years after rig release date in the case of an exploration well, or 60 days after rig release date in the case of a development well.
 - (d) Available for public use: As part of the Final Well Report.
 - (e) Log catalog available: List of final well reports.
3. Multiple completion regulation:
 - (a) Approval obtained: Regulation being developed.
 4. Commingling in well bore:
 - (a) Approval obtained: Regulation being developed.

Oil Production

Note: Production and Conservation Regulations for onland production are being developed. In the interim, oil production is based on approved development plan as required in the *Petroleum Regulations*.

1. Definition of an oil well: To be included in new regulations.
2. Potential tests required:
 - (a) Time interval: See note above.
 - (b) Witness required: See note above.
3. Statewide allowable:
 - (a) Pool allowable: Not applicable.
 - (b) Well allowable: Not applicable.
 - (c) Exempt allowable: Not applicable.
4. Maximum gas-oil ratio:
 - (a) Provision for limiting gas-oil ratio: See note above.
 - (b) Exception to limiting gas-oil ratio: See note above.
5. Bottom-hole pressure test reports required:
 - (a) Periodical bottom-hole pressure surveys: See note above.
6. Commingling oil in common facilities: See note above.
7. Measurement involving meters: See note above.
8. Production reports:

- (a) By lease: See note above.
- (b) By well: See note above.
- (c) Time limit: See note above.

Gas Production

Note: Production and Conservation Regulations for onland production are being developed. In the interim, gas production is based on approved development plan as required in the *Petroleum Regulations*.

1. Definition of a gas well: See note above.
2. Pressure base _____ psia @ _____ degrees F. See note above.
3. Initial potential tests:
 - (a) Time interval: See note above.
 - (b) Witness required: See note above.
4. Statewide allowable:
 - (a) Pool allowable: N/A
 - (b) Well allowable: N/A
 - (c) Exempt allowable: N/A
5. Bottom-hole pressure test reports required:
 - (a) Periodical bottom-hole pressure surveys: See note above.
6. Commingling of gas in common facilities: See note above.
7. Measurement involving meters: See note above.
8. Production reports:
 - (a) By lease: See note above.
 - (b) By well: See note above.
 - (c) Time limits: See note above.

Underground Injection

1. State agencies that control the underground injection of fluids: Department of Natural Resources.

Unitization

1. Compulsory unitization of all or part of a pool or common sources of supply: As per approved development plan.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: As per approved development plan.

- (c) Royalty interest: As per approved development plan.

Taxation

Gas severance tax = Under review
 Gas ad valorem tax = Under review
 Total gas tax burden = Under review

Oil severance tax = Royalty Regime – onshore only
 Oil ad valorem tax = Royalty Regime – onshore only
 Total oil tax burden = Royalty Regime – onshore only

1. Tax collecting agency: Royalty collected by the Department of Natural Resources.
2. How tax is computed: Generic Onshore Royalty Regime. Based on value of production to a threshold and then a percentage of net profits from the field.
3. Exemptions or exceptions: 2 million barrel royalty holiday.
4. Name of tax: Basic royalty, net royalty.
5. Statutory citation: *Petroleum and Natural Gas Act*.

Land Leasing Information

1. Leasing Method: Work commitment (or as noted by the Minister in Request for Bids)
2. Notice Method: Request for Bids. Published in newspapers and by press release.
3. Minimum bidding \$ (per acre): None (or as noted by the Minister in Request for Bids)
4. Qualification of the bidder: As noted in Request for Bids (Deposit of 20% of work commitment)
5. State Statutes: *Petroleum and Natural Gas Act, Petroleum Regulations*
6. Maximum acres: 40,000 ha
7. Contact: Fred Allen, Director (A), Policy and Strategic Planning. Phone: (709) 729-2778.

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: Dept. of Environment, Government of Newfoundland and Labrador
2. Relevant Statute/Regulations: *Provincial Environmental Protection Act*.
3. Scope: Province wide.
4. Licensing: Storage only.
5. Cleaning Equipment: None.
6. Disposal of Waste: Restricted.
7. Subsequent Use of Equipment: None.

8. Subsequent Use of Materials: No re-use.
9. Release/Sale of NORM-Contaminated Land: Not applicable.
10. Projected Volume of stored NORM in the State: Steel leak proof containers: length (40ft) x height (9ft:6inch) x width (6ft:2inch)
11. Respondent: Sam El-Gohary, Pollution Prevention Division, November 24, 2003.

REPUBLIC OF GEORGIA

Administration

1. State agency: State Agency for the Regulation of Oil and Gas Resources of Georgia (SAROGR), 45, Kazbegi Avenue, Tbilisi, Georgia 380077. Phone: (99532) 253311, 253399; Fax: (99532) 253311.

The Regulations do not prescribe the specific steps an Investor must undertake in order to achieve the desired result. Instead, they clearly state goals and objectives that must be achieved, such as safe conduct of oil and gas operations, conservation of oil and gas resources, protection of the environment and such.

The Regulations provide basic guidelines of conduct, set principal criteria for Investor's performance and it will be up to the Operator to decide how it will go about achieving the stated goal. However, all Investors are obliged to comply with the international standards.

2. Docketing procedure: Each Operator who receives a notice of probable violation from SAROGR may respond by: (1) Correcting condition that is a probable violation within the time specified in the notice of violation and paying any fine or penalty assessed in a final administrative decree; (2) Attempting to resolve any disputed issue or issue related to probable violation through correspondence or discussions with Agency personnel; or (3) Filing a written request for a hearing.

Within five (5) business days of receipt of a request for hearing or a complaint, the Head of the Agency shall designate an employee of the Agency. In the event that there is no employee of the Agency who is qualified to serve as a Dispute Resolution Representative the Head of the Agency may appoint an independent, qualified and unbiased person who is not an employee of the Agency as Dispute Resolution Representative to serve as the Dispute Resolution Representative for the matter, and assign a case number to the matter. No employee who has been materially involved in the investigation of the alleged violation or the preparation of the notice may be designated as a Dispute Resolution Representative. The Dispute Resolution Representative shall establish a schedule for the filing of all motions, completion of discovery procedures, and any preliminary hearings. Motions and discovery shall be conducted in a manner conforming to the Code of Civil Procedure Code.

- (a) Emergency orders: Nothing contained in the Regulation shall prevent or delay the Head of the Agency from issuing administrative decrees or taking other action permitted by law to order the emergency suspension or cessation of Oil and Gas Operations that, in the opinion of the Head of the Agency, are necessary to protect life, health, property, or the environment from imminent harm.
- (b) Notice: If the Agency determines that a probable violation of these Regulations has occurred, the Head of the Agency or the proper designee shall prepare and deliver to the Operator's principal office in Georgia a written preliminary notice of violation containing at least the following information:
 - The Agency's case number and other designation of the notice;
 - The date, location, and specific nature of the probable violation;
 - A reference to the specific Regulation asserted by the Agency to have been violated;
 - A specific time period in which any violation shall be corrected
 - The amount of fines or penalties that the Agency proposes to assess for a violation and the amount proposed to be assessed if the probable violation is not corrected;
 - The name and telephone number of an Agency employee to be contacted for further information;
 - The method by which the notice of probable violation may be contested under this Chapter, including the time periods within a contest must be filed.

If a Person served with a notice of probable violation does not respond in one of the ways set out in this section within thirty (30) days, the Head of the Agency may enter an administrative decree finding that the violation has occurred and setting penalties.

Bond

1. Compliance bond required: Yes. The Agency may require an Operator to furnish a bond or bonds that guarantees compliance with the obligations under a Contract and these Regulations that are related to the abandonment or decommissioning of oil or gas facilities, including the abandonment of wells, removal of platforms, restoration of any lands or surface waters adversely affected by Oil and Gas Operations and clearance of equipment and facilities from the Contract Area within the following period.
 - (a) Forty-five (45) days after a proposed Plan is approved the Agency, or
 - (b) One hundred and twenty (120) days after the effective date of these Regulations for any existing Contract pursuant to which a Plan has been previously approved.
2. Conditions of bond: The Operator furnishes and maintains an area-wide bond in an amount agreed to by the Agency issued by a qualified surety and conditioned on compliance with all the terms and conditions of all Contracts held by the Operator within Georgia.
 - (a) The Operator is required by its Contract to establish, or the Agency accepts the establishment of an abandonment account in lieu of such bond pursuant to Article 31 of the Regulations, or
 - (b) The Agency accepts a third party guarantee or letter of credit in lieu of such bond pursuant to Article 32 of the Regulations.

Spacing

1. Spacing requirements: No. In the Appraisal Plan the operator should provide information on the approximate location of each appraisal well, including surface location, bottom hole location and proposed total well depth field, upon completion.

Pooling

1. Authority to establish voluntary: Yes. The Agency may approve an application for Joint Development of a Oil and Gas Reservoir(s) if Joint Development (a) is likely to promote or expedite Oil and Gas Operations, (b) is likely to conserve natural resources or protect the rights of adjacent Operators with respect to a common Oil and Gas Reservoir.

Prior to undertaking any activities pursuant to a proposed Joint Development Plan, an application for Joint Development must be submitted to, and approved by, the Agency pursuant to the Oil and Gas Regulations, and the applicable provisions of the Oil and Gas Law and any Contract.

2. Authority to establish compulsory: Yes. The Agency may, either on its own initiative or upon the application of an Operator, require Joint Development of a single, continuous and common Reservoir if (a) Joint Development is required to conserve natural resources or protect the rights of adjacent Operators with respect to such Reservoir, and (b) the Oil and Gas accumulation in such Reservoir extends across the boundary of a Contract Area or License into the area which comprises a separate Contract Area or License.
3. Procedure for Notice of Compulsory Joint Development: The Agency shall provide a written notice of the proposed Joint Development to all interested Operators.

The Operators shall have one hundred and eighty (180) days after receipt of such notification to submit a voluntary Joint Development Plan to the Agency.

If the interested Operators and Contractors fail to submit a voluntary Joint Development Plan within the specified time period, the Agency may provide all such parties with written notice of its intent to proceed under paragraphs 3, 4, 5 and 6 of article 109 of the Regulation and shall invite the Operators affected to submit proposed Joint Development Areas for its consideration.

The Agency may refer the matter to an Independent Dispute Resolution Representative who shall proceed as set forth in Chapter LXX and LXXI of the Regulations, or if all Operators agree, the Agency may proceed to hold a Hearing.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well: Yes.
 - (b) Seismic drilling: No (included in seismic permit).
 - (c) Recompletion: Yes.
 - (d) Plugging and abandoning: Yes.
2. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement:
 - (a) When is directional survey necessary? During the drilling.
 - (b) Filing of survey required? Yes. Should be filed in the Drilling Completion Report.

Casing and Tubing

1. Minimum amount required: No. Regulation includes only general requirements: "The Operator shall case all wells with a sufficient number of strings of casing and use a sufficient quality and quantity of cement on each string of casing in a manner necessary to prevent release of fluids from any stratum through the wellbore, prevent communication between separate strata, protect underground sources of fresh, potable water or water used for hydro-therapeutic purposes and geothermal resources from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids."
 - (a) Surface casing:
 - (b) Production casing:
2. Minimum amount of cement required: No. If there are indications of inadequate cementing, the Operator shall evaluate the adequacy of the cementing operations in accordance with International Oil Field Practice. If the evaluation indicates inadequate cementing to the extent that the requirements of 1 of Article 80 are unlikely to be achieved, the Operator shall re-cement or take other remedial action as required according to International Oil Field Practice.
 - (a) Surface casing:
 - (b) Production casing:
 - (c) Setting time: Not more 24 hours.
3. Tubing requirements: No specific predefined requirement. Operator shall: (a) ensure that all tubing has the necessary strength and pressure integrity and is otherwise suitable for its intended use, and (b) conduct integrity testing in the event of prolonged operations. All wells shall be completed with tubing installed unless an exception to such requirement has been approved by the Agency.
 - (a) Oil wells:
 - (b) Gas wells:

Completion

1. Completion report required: Yes.
 - (a) Time limit: The report should be submitted within 1, 5 month.
 - (b) Where submitted: SAROGR
2. Well logs required to be filed: Yes.
 - (a) Time limit: 1.5 month.
 - (b) Where submitted: SAROGR
 - (c) Confidential time period: 5 years.
 - (d) Available for public use: Yes.
 - (e) Log catalog available: No
3. Multiple completion regulation:
 - (a) Approval obtained: Yes.
4. Commingling in well bore:
 - (a) Approval obtained: Yes.

Oil Production

1. Definition of an oil well: Not
2. Potential tests required: Yes.
 - (a) Time interval: On the case by case basis.
 - (b) Witness required: Yes.

Statewide allowable: Yes. According to the Regulations. (1) Oil and Gas Reservoirs shall not be produced in excess of the Maximum Efficient Rate as defined and averaged in a relevant Plan or modification thereto. (b) An initial Maximum Production Rate for each well shall be proposed in any relevant Plan by Operator taking into account such factors as limitations imposed by well and surface equipment, san production, gas-oil and water-oil ratios, location of perforated intervals, prudent operating practices, and the Operator's ability to transport and market any produced Oil and Gas. Wells shall not be produced in excess of the Maximum Production Rate. Subject to Article 5 of the regulation, a revised Maximum Production Rate may be periodically proposed by the Operator and submitted to the Agency for approval. The mathematical sum of all the Maximum Production Rates may exceed the Maximum Efficient Rate as defined in paragraph

3.
 - (a) Pool allowable:
 - (b) Well allowable:

- (c) Exempt allowable: Yes.
- 4. Maximum gas-oil ratio: To be defined by Operator and approved by the Agency.
 - (a) Provision for limiting gas-oil ratio: Not.
 - (b) Exception to limiting gas-oil ratio: Not.
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: Should be included in Operator's Plan.
- 6. Commingling oil in common facilities: An Operator may apply to commingle hydrocarbons produced from different Reservoirs within a common wellbore. Applications for downhole commingling shall include the following information: (1) geologic and reservoir engineering data, (2) a schematic diagram of well equipment and completion techniques, (3) other pertinent well information and (4) description of measures to be taken to prevent Waste of Oil and Gas.

The applications shall be approved where the commingled production will not reduce the Ultimate Economic Recovery of Oil and Gas from any Reservoir(s) so produced but, instead, will promote the conservation of Oil and Gas. Such Applications may be disposed of by approval of the Agency, without hearing or upon hearing pursuant to title XIII of 13 of the regulation.
- 7. Measurement involving meters: Yes.
- 8. Production reports: Yes.
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limit: Monthly; Annual.

Gas Production

- 1. Definition of a gas well: Not
- 2. Pressure base _____ psia @ _____ degrees F.
- 3. Initial potential tests: To be defined case by case basis.
 - (a) Time interval:
 - (b) Witness required:
- 4. Statewide allowable: Same as in case of Oil.
 - (a) Pool allowable:
 - (b) Well allowable:
 - (c) Exempt allowable:
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Periodical bottom-hole pressure surveys: To be determined by the Operator.

6. Commingling of gas in common facilities: Same as in case of Oil.
7. Measurement involving meters: Yes.
8. Production reports: Yes.
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limits: Monthly; Annual.

Underground Injection

1. State agencies that control the underground injection of fluids: SAROGR and Ministry of Environment Protection.

Unitization

1. Compulsory unitization of all or part of a pool or common sources of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization: Not.
 - (a) Working interest: Not.
 - (b) Royalty interest: Not.

Taxation

Gas severance tax = from 5 to 10% (usually 5% for onshore and 7% for offshore).
 Gas ad valorem tax = usually it is a 20% by the Tax Law of Georgia, but for the Oil and Gas Operations there are special tax exemptions for the acting companies.
 Total gas tax burden = N/A

Oil severance tax = 5 from 5 to 10% (usually 5% for onshore and 7% for offshore).
 Oil ad valorem tax = usually it is a 20% by the Tax Code of Georgia, but for the Oil and Gas Operations there are special tax exemptions for the acting companies.
 Total oil tax burden = N/A

1. Tax collecting agency: Ministry of Finance through it's Tax Departments.
2. How tax is computed: In accordance to the Georgian Tax code by appropriate tax agencies.
3. Exemptions or exceptions: Yes.
4. Name of tax: Customs Duties; Company Property Tax; Land Tax; Excise Tax; Advertisement Tax; Economic Tax; Tax on Ownership of Motor Vehicles; Tax on Transfer of Motor Vehicles; Tax on entering Motor Vehicles into the Territory of Georgia; Tax on Pollution of the Environment and Harmful Substances, other Taxes.
5. Statutory citation: Tax Code - Economic Tax, Part 14, Chapter 48, Article 273 Closure 32; Movables - Part 8, Chapter 26, Chapter 26, Closure 166-V; VAT - Part 3, Chapter 14, Article 101-111.

Land Leasing Information

According to Article 20 of the Oil and Gas Law - On the basis of License for Usage of Oil and Gas Resources and relevant Agreement issued by the Agency, the Agency shall simultaneously issue a permit on usage of Land Allotment to Investor prepared by the State Department of Land Management of Georgia.

In the event the land required for Oil and Gas Operations belongs to an individual or legal entity (which is not the State), then Investor prior to signing Agreement shall conclude an agreement with the landowner for the exclusive usage of the required land for the entire period of the Agreement. Investor shall submit such agreement to the Agency for concluding Agreement in accordance with rules established by the Agency.

The Agency is invested with the right to appeal to court for Eminent Domain. The Agency shall prepare and adopt rules and normative acts that shall govern the exercise of the power of Eminent Domain.

1. Leasing Method:
2. Notice Method: Not.
3. Minimum bidding \$ (per acre): Not.
4. Qualification of the bidder: Not.
5. State Statutes: Yes.
6. Maximum acres: Not limited but for the producing well is 360 m².
7. Contact: SAROGR

Naturally Occurring Radioactive Material (NORM)

1. Regulating Agency: SAROGR and Ministry of Environment Protection.
2. Relevant Statute/Regulations: Oil and Gas Regulations.
3. Scope:
4. Licensing: Not required.
5. Cleaning Equipment: Yes.
6. Disposal of Waste: Yes, prior to undertaking any Oil and Gas Operations, Operators shall submit an Oil and Gas Waste Disposal Plan as a part of Environmental Protection Plan to the Agency for approval. No disposal of Oil and Gas Waste shall take place unless an Operator obtains an Oil and Gas Disposal Permit from the Agency.
7. Subsequent Use of Equipment: Yes.
8. Subsequent Use of Materials: Yes.
9. Release/Sale of NORM-Contaminated Land: Not.
10. Projected Volume of stored NORM in the State: Not.
11. Respondent:

NOTE: The section on Federal and Indian land and offshore is in two parts. The first section covers onshore exploration and production; the second section commences on page US-5 and covers the Outer Continental Shelf.

BUREAU OF LAND MANAGEMENT (BLM)
ONSHORE OPERATIONS
FEDERAL AND INDIAN LAND (Except Osage)

Administration

1. Agency: Director, Bureau of Land Management, 1849 C Street, Washington, D.C. 20240.
2. Docketing procedure: Do not hold hearings as such. Appeals can be made.
 - (a) Emergency orders: Yes.
 - (b) Notice: The Director, Bureau of Land Management, is responsible for oil and gas orders and notice to lessees and operators.

Bond

1. Compliance bond required: Yes.
2. Conditions of bond: As provided for in regulations. (Varies by land category.)
 - (a) Amount per well: Do not have per well bond.
 - (b) Amount of blanket bond: Federal leases - adjustable, minimums are \$10,000 per lease, \$25,000 per State, \$150,000 nationwide. Indian leases - variable \$1,000 to \$8,000 per lease, \$15,000 per state, \$75,000 nationwide.

Spacing

1. Spacing requirements: No minimum.
 - (a) Density: Set by appropriate District Manager in cooperation with the state.
 - (b) Lineal: Set by appropriate District Manager.
2. Exceptions: Yes.
 - (a) Basis: For good cause where not prohibited by law.
 - (b) Approval: From appropriate District Manager.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes - Not normally invoked.

Drilling Permit

1. Require permits for:
 - (a) Drilling a producing or service well? Yes.

- (b) Seismic drilling: No.
 - (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes.
2. Permit fee: None required.
- (a) Drilling: N/A.
 - (b) Seismic Drilling: N/A.
 - (c) Recompletion: N/A.
 - (d) Plugging and abandoning: N/A.
3. Require filing report of work performed: Yes.

Vertical Deviation

1. Regulation requirement: No.
- (a) When is directional survey necessary? All directionally drilled wells.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:
- (a) Surface casing: As conditions warrant.
 - (b) Production casing: As conditions warrant.
2. Minimum amount of cement required:
- (a) Surface casing: Cemented to surface.
 - (b) Production casing: As conditions warrant.
 - (c) Setting time: No.
3. Tubing requirements:
- (a) Oil wells: No.
 - (b) Gas wells: No.

Completion

1. Completion report required: Yes.
- (a) Time limit: 30 days after completion.
 - (b) Where submitted: Appropriate District Office.

2. Well logs required to be filed: Yes.
 - (a) Time limit: 30 days after well completion.
 - (b) Where submitted: Appropriate District Office.
 - (c) Confidential time period: Yes, if requested, until lease expires.
 - (d) Available for public use: No.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes.
 - (a) Approval obtained: Application to appropriate District Manager.
4. Commingling in well bore: Yes.
 - (a) Approval obtained: Application to appropriate District Manager.

Oil Production

1. Definition of an oil well: Classified by completion as to oil or gas production. No formal definition between oil wells or gas wells.
2. Potential tests required: No, not generally.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
3. Statewide allowable: No. State allowables usually honored.
 - (a) Pool allowable: N/A.
 - (b) Well allowable: N/A.
 - (c) Exempt allowable: N/A.
4. Maximum gas-oil ratio: No, but can be established by appropriate District Manager.
 - (a) Provision for limiting gas-oil ratio: As established.
 - (b) Exception to limiting gas-oil ratio: By discretion of appropriate District Manager.
5. Bottom-hole pressure test reports required: Yes, as requested.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling oil in common facilities: Yes.
7. Measurement involving meters: Yes.
8. Production reports:

- (a) By lease: Yes. (By each operator on the lease.)
- (b) By well: Yes.
- (c) Time limit: By the 15th of second month following the production month.

Gas Production

1. Definition of a gas well: Classification by completion as to oil or gas production. No formal definition between oil wells and gas wells.
2. Pressure base 14.73 pisa @ 60 degrees F.
3. Initial potential tests: No.
 - (a) Time interval: N/A.
 - (b) Witness required: N/A.
4. Statewide allowable: Generally use applicable State schedules.
 - (a) Pool allowable: N/A.
 - (b) Well allowable: N/A.
 - (c) Exempt allowable: N/A.
5. Bottom-hole pressure test reports required: Yes, when requested by appropriate District Manager.
 - (a) Periodical bottom-hole pressure surveys: No.
6. Commingling of gas in common facilities: Yes, by discretionary authority of appropriate District Manager.
7. Measurement involving meters: Yes.
8. Production reports:
 - (a) By lease: Yes. (By each operator on the lease.)
 - (b) By well: Yes.
 - (c) Time limit: By the 15th of the second month following the production month.

Water Disposal

1. Agencies that control disposal of produced salt water: BLM and EPA.

Unitization

1. Unitization of all or part of a pool or common source of supply: Yes.
2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: Not established, but must protect the rights of all interest owners.

- (b) Royalty interest: Same as (a) above.

MINERALS MANAGEMENT SERVICE OUTER CONTINENTAL SHELF OPERATIONS

Administration

1. Agency: Director, Minerals Management Service, 1849 C Street, Washington, D.C. 20240.
2. Docketing procedure: Do not hold hearings as such. Appeals can be made.
 - (a) Emergency orders: Yes. The appropriate Regional Director is responsible for Notices to Lessees and Operators.
 - (b) Notice: 30 days minimum.

Bond

1. Compliance bond required: Yes. Issuance of lease \$50,000.
2. Conditions of bond: Surety bond of \$50,000; Exploration Plan approval \$200,000; Development and Production Plans and Development Operations Coordination Documents approval \$500,000.
 - (a) Amount per well: On lease basis.
 - (b) Amount of blanket bond: \$300,000, \$1 Million, or \$3 Million. Final Rule published on August 27, 1993, (58FR 45255).

A final rule was published on 5/22/97 (62 FR 27948) to establish December 8, 1997 as a deadline for every lessee to comply with the bond coverage requirements.

Spacing

1. Spacing requirements: Yes. Approval of Regional Supervisor needed.
 - (a) Density: As required for drainage protection, optimum position on structure and for avoidance of unnecessary wells.
 - (b) Lineal: Not less than 500' from property line unless prior approval of Regional Supervisor.
2. Exceptions: Yes.
 - (a) Basis: By letter of no objection from offset properties.
 - (b) Approval: Regional Director.

Pooling

1. Authority to establish voluntary: Yes.
2. Authority to establish compulsory: Yes.

Drilling Permit

MMS has revised forms to alleviate redundant reporting and clarify other permit and reporting requirements (see 67 FR 536090). The revisions are also needed for the ongoing transformation to an "E-Forms Permit and Report Process". NTL 2004-G10 (Effective Date June 1, 2004) implements the eWell Permitting and Reporting System. A final rule on Oil and Gas Drilling Operations was published February 20, 2003 (64 FR 2660) and became effective March 24, 2003.

1. Require permits for:
 - (a) Drilling a producing or service well? Yes.
 - (b) Seismic drilling? Yes.
 - (c) Recompletion? Yes.
 - (d) Plugging and abandoning? Yes.
2. Permit fee:
 - (a) Drilling: None.
 - (b) Seismic drilling: None.
 - (c) Recompletion: None.
 - (d) Plugging and abandoning: None.
3. Require filing report of work performed: Yes.
 - (a) Application for Permit to Modify; or
 - (b) Well (Re)Completion Report; or
 - (c) Notice of Intent/Report of Well Decommissioning; or
 - (d) End of Operations Report; or
 - (e) Well Activity Report.

Vertical Deviation

1. Regulation requirement: Yes.
 - (a) When is directional survey necessary? For directional wells at intervals not exceeding 500' prior to, or upon setting surface or intermediate casing, liners, and at total depth. (100' when angle changes are planned.) For vertical wells, at intervals not exceeding 1000'.
 - (b) Filing of survey required? Yes.

Casing and Tubing

1. Minimum amount required:

- (a) Surface casing: Yes.
 - (b) Production casing: No.
2. Minimum amount of cement required:
- (a) Surface casing: Yes.
 - (b) Production casing: Yes.
 - (c) Setting time: Eight hours for conductor casing; all others require 12 hours.
3. Tubing requirements: Yes.
- (a) Oil wells: As needed.
 - (b) Gas wells: As needed.

Completion

1. Completion report required: Yes.
- (a) Time limit: Within 30 days after completion.
 - (b) Where submitted: District Supervisor.
2. Well logs required to be filed: Yes.
- (a) Time limit: Within 30 days after completion.
 - (b) Where submitted: Regional office.
 - (c) Confidential time period: Considered proprietary data.
 - (d) Available for public use: No.
 - (e) Log catalog available: No.
3. Multiple completion regulation: Yes.
- (a) Approval obtained: Regional Supervisor.
4. Commingling in well bore: Yes.
- (a) Approval obtained: Regional Supervisor.

Oil Production

1. Definition of an oil well: Completed in oil reservoir or in oil reservoir with an associated cap.
2. Potential tests required: Yes. MMS-126, Well Potential Test Report. New form numbers as published on March 16, 1994. (59FR 12161)
- (a) Time interval: Within 30 days of the date of first continuous production.

- (b) Witness required: When required by Regional Supervisor.
- 3. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
- 4. Maximum gas-oil ratio: No.
 - (a) Provision for limiting gas-oil ratio: Yes. If high GOR would affect ultimate recovery.
 - (b) Exception to limiting gas-oil ratio: Yes. After application.
- 5. Bottom-hole pressure test reports required: Yes.
 - (a) Within 3 months after the date of first continuous production.
 - (b) Periodical bottom-hole pressure surveys: Yes. On annual basis.
- 6. Commingling oil in common facilities: Yes.
- 7. Measurement involving meters: Yes.
- 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limit: By the 15th of the second month following the production month.

Gas Production

- 1. Definition of a gas well: A well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.
- 2. Pressure base 14.73 psia @ 60 degrees F. (15.025 psia in the Gulf of Mexico).
- 3. Initial potential tests: Yes.
 - (a) Time interval: Initial, 30 days after pipeline connection; semiannually thereafter.
 - (b) Witness required: When required by Regional Supervisor.
- 4. Statewide allowable: No.
 - (a) Pool allowable: No.
 - (b) Well allowable: No.
 - (c) Exempt allowable: No.
- 5. Bottom-hole pressure test reports required: Yes.

- (a) Periodical bottom-hole pressure surveys: Yes. On annual basis.
- 6. Commingling of gas in common facilities: Yes.
- 7. Measurement involving meters: Yes.
- 8. Production reports:
 - (a) By lease: Yes.
 - (b) By well: Yes.
 - (c) Time limit: By the 15th of the second month following the production month.

Water Disposal

- 1. Agencies that control disposal of produced salt water: MMS and Environmental Protection Agency.

Unitization

- 1. Compulsory unitization of all or part of a pool or common source of supply: Yes. Director may you and other lessees to unitize operations as deemed necessary. Final rule on unitization published on 2/5/97 (62 FR 5329).
- 2. Minimum percentage of voluntary agreement before approval of compulsory unitization:
 - (a) Working interest: N/A.
 - (b) Royalty interest: N/A.

Oil Spill Financial Responsibility

- 1. Financial evidence required: Yes, for any offshore facility with the potential of an oil/gas condensate spill of 1,000 barrels or more. This amount may be reduced for high risk areas.
- 2. Types of financial evidence acceptable: Self-insurance (based on audited annual financial statements), indemnification by another corporation in their corporate family (based on self-insurance procedures), property and casualty insurance, surety bonds, or some combination of these.
- 3. Types of offshore facilities requiring coverage: Those used for: exploring for (including geological exploration), drilling for, or producing oil on the outer continental shelf, state coastal waters (including bays or estuaries) seaward of the line of ordinary low water; or transporting oil across these waters from facilities engaged in exploration, drilling, or production.
- 4. Amount of required financial evidence:
 - (a) From \$35 million to \$150 million on the outer continental shelf.
 - (b) From \$10 million to \$150 million on state coastal waters seaward of the line of ordinary low water.
- 5. Basis for certification: On a lease basis, which includes pipeline right-of-ways as a type of lease, to a Designated Applicant selected by the Responsible Parties (i.e., Lessees for leases, and Owners and Operators for pipelines).

A final rule was published on 8/11/98 (63 FR 42699) to establish October 13, 1998, as the effective date of the rule and April 8, 1999, as the deadline for compliance.

Fixed and Floating Platforms and Structures

1. Definition of facility
 - (a) All installations permanently or temporarily attached to the seabed on the OCS.
 - (b) Includes any vessel used to transfer production from an offshore facility.
 - (c) Used for drilling, well completion, well workover, or production operations.
 - (d) All installations that emit or have the potential to emit any air pollution from one or more sources.
2. Platforms and Structures
 - (a) General requirements- design, fabricate, install, use, maintain, inspect, and assess all platforms and related structures on the OCS so as to ensure their structural integrity for the safe conduct of drilling workover, and production operations.
 - (b) Submit application and obtain approval before platform installation, major platform modification, major repair, platform conversion, or MODU conversion.

A final rule was published on 7/19/05 (70 FR 41556) .

New Fees

A final rule published on July 19, 2007 (71 FR 40904) established new fees to process certain plans, applications and permits. See table below:

SERVICE FEE TABLE

Service – processing of the following:	Fee amount	30 CFR citation
Change in Designation of Operator.	\$150	§ 250.143
Suspension of Operations/Suspension of Production (SOO/SOP) Request.	\$1,800	§ 250.171
Exploration Plan (EP).	\$3,250 for each surface location, no fee for revisions.	§ 250.211
Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD).	\$3,750 for each well proposed, no fee for revisions.	§ 250.241(e)
Deepwater Operations Plan.	\$3,150	§ 250.292(p)
Conservation Information Document.	\$24,200	§ 250.296(a)
Application for Permit to Drill (APD; Form MMS-123).	\$1,850 Initial applications only, no fee for revisions.	§ 250.410(d); § 250.411; § 250.460; § 250.513(b); § 250.515; § 250.1605; § 250.1617(a); § 250.1622
Application for Permit to Modify (APM; Form MMS-124).	\$110	§ 250.460; § 250.465(b); § 250.513(b); § 250.515; § 250.613(b); § 250.615; § 250.1618(a); § 250.1622; § 250.1704(g)

Service – processing of the following:	Fee amount	30 CFR citation
New Facility Production Safety System Application for facility with more than 125 components.	\$4,750 A component is a piece of equipment or ancillary system that is protected by one or more of the safety devices required by API RP 14C (incorporated by reference as specified in § 250.198). (Additional fee of \$12,500 will be charged if MMS deems it necessary to visit a facility offshore; and \$6,500 to visit a facility in a shipyard).	§ 250.802(e)
New Facility Production Safety System Application for facility with 25–125 components.	\$1,150 (Additional fee of \$7,850 will be charged if MMS deems it necessary to visit a facility offshore; and \$4,500 to visit a facility in a shipyard).	§ 250.802(e)
New Facility Production Safety System Application for facility with fewer than 25 components.	\$570	§ 250.802(e)
Production Safety System Application – Modification with more than 125 components reviewed.	\$530	§ 250.802(e)
Production Safety System Application – Modification with 25–125 components reviewed.	\$190	§ 250.802(e)
Production Safety System Application – Modification with fewer than 25 components reviewed.	\$80	§ 250.802(e)
Platform Application – Installation – under the Platform Verification Program.	\$19,900	§ 250.905(k)
Platform Application – Installation – Fixed Structure Under the Platform Approval Program.	\$2,850	§ 250.905(k)
Platform Application – Installation – Caisson/Well Protector.	\$1,450	§ 250.905(k)
Platform Application – Modification/Repair.	\$3,400	§ 250.905(k)
New Pipeline Application (Lease Term).	\$3,100	§ 250.1000(b)
Pipeline Application – Modification (Lease Term).	\$1,800	§ 250.1000 (b)
Pipeline Application – Modification (ROW).	\$3,650	§ 250.1000 (b)
Pipeline Repair Notification.	\$340	§ 250.1008 (e)
Pipeline Right-of-Way (ROW) Grant Application.	\$2,350	§ 250.1015
Pipeline Conversion of Lease Term to ROW.	\$200	§ 250.1015
Pipeline ROW Assignment	\$170	§ 250.1018
500 Feet From Lease/Unit Line Production Request.	\$3,300	§ 250.1101
Gas Cap Production Request.	\$4,200	§ 250.1101
Downhole Commingling Request.	\$4,900	§ 250.1106
Complex Surface Commingling and Measurement Application.	\$3,550	§ 250.1202(a); § 250.1203(b); § 250.1204(a)
Simple Surface Commingling and	\$1,200	§ 250.1202(a); § 250.1203(b);

Service – processing of the following:	Fee amount	30 CFR citation
Measurement Application.		§ 250.1204(a)
Voluntary Unitization Proposal or Unit Expansion.	\$10,700	§ 250.1303
Unitization Revision.	\$760	§ 250.1303
Application to Remove a Platform or Other Facility.	\$4,100	§ 250.1727
Application to Decommission a Pipeline (Lease Term).	\$1,000	§ 250.1751(a) or § 250.1752(a)
Application to Decommission a Pipeline (ROW).	\$1,900	§ 250.1751(a) or § 250.1752(a)

APPENDIX

D

Exploratory Unitization Under the 2004 Model Oil and Gas Conservation Act: Leveling the Playing Field

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I. INTRODUCTION

In 1999, for the fiftieth anniversary of the Southwestern Legal Foundation, now the Center for American and International Law, we co-authored an essay addressing the use of state law to promote more domestic exploration and production through means other than tax relief and tax incentives.¹ Specifically, we focused on the increasing problems of mineral fractionalization and subdivision, which together greatly increase the costs of domestic onshore exploration and production; often greatly reduce the rewards of a new discovery to the discovering party; and make offshore and overseas investments comparatively much more attractive. Subsequent events have forcefully revealed the risks of increased reliance on imported foreign oil and the desirability of efficiently developing domestic petroleum reserves.

To confront the problems of fractionalization and subdivision, we argued in our 1999 essay for the elimination of legal barriers to domestic exploration and development. Our principal proposal—both then and today—is early unitization of oil and gas fields, including unitization at the exploratory stage. Although most oil and gas producing states have compulsory unitization acts, most existing acts do not expressly authorize compulsory unitization for purposes of exploration. The 2004 version of the Model Oil and Gas Conservation Act (Model Act)² includes model compulsory exploratory unitization provisions that are consistent with what we advocated in our 1999 essay.

While exploratory unitization has been possible respecting federal acreage for many years, the provisions of the Model Act apply to privately-owned and state-owned lands and replicate, to the extent possible, the manner in which

¹ See generally Owen L. Anderson & Ernest E. Smith, *The Use of Law to Promote Domestic Exploration and Production*, 50 INST. ON OIL & GAS L. & TAX'N 2-1 (1999).

² MODEL OIL AND GAS CONSERVATION ACT (2004). The Model Act was originally drafted by the Interstate Oil Compact Commission (now the Interstate Oil and Gas Compact Commission (IOGCC)) in 1941 and has been periodically modified since that time.

exploration rights are typically conferred in other countries. A major reason that operators, now including an increasing number of independent companies, find foreign exploration so attractive is that they can acquire exclusive rights to explore and develop large acreages without having to confer an unearned benefit to other operators who may specialize in capitalizing on the exploration risks taken by others by acquiring acreage within the same prospect. Because the geography of exploration and production blocks will seldom be fully consistent with the geology of a reservoir, this unwanted competition cannot always be eliminated, but it is greatly decreased due to the size of the typical exploration block, which is often as large as 50,000 acres. Even large reservoirs are not likely to overlap more than one competing block. In any event, where an overlap occurs, the host government mandates cooperative unit operations before any actual development and production can take place.

I. THE RULE OF CAPTURE AND WELL-BY-WELL REGULATION

Historically, the rule of capture governed the development of oil and gas reservoirs in the United States. Under the rule of capture, producers were not liable to each other for drainage across boundary lines.³ Unfortunately, this rule of capture development caused waste that could not be ameliorated without government regulation. More wells were drilled to offset drainage than were needed to drain the reservoir efficiently, thereby causing economic waste. The proliferation of wells led to the proliferation of related storage tanks, pipes, and valves, all of which were prone to leakage and to catching fire, thereby causing surface waste and environmental damage. The resulting "flush" production that resulted from the drilling of too many wells inefficiently dissipated the natural reservoir energy that pushed the oil and gas through the reservoir and into well bores, thereby causing underground waste. Because of this rapid dissipation of internal reservoir pressure, hydrocarbons that would otherwise have been produced became unrecoverable. In addition, during the early years of the twentieth century the high production rates caused oil prices to drop to the point where wells could not be drilled and produced at a profit. Because there were typically many interest owners overlying a common reservoir, high transaction costs and strategic behavior prevented the successful negotiation of a voluntary agreement to curtail this frenzied, costly, and wasteful development.

The standard legislative response to rule of capture development has been regulation in the form of well spacing and density regulations and compulsory pooling. As typically practiced, spacing and density regulations require the conservation agency to determine, theoretically, the area that can be efficiently and effectively drained by one well within a given reservoir and then to

³ See, e.g., *Kelly v. Ohio Oil Co.*, 49 N.E. 399, 401 (Ohio 1897).

regulate drilling on that basis. Under this traditional approach, each spacing or drilling unit is entitled to one well, although over time the drilling of additional “in fill” wells may be permitted.

If a given drilling unit contains multiple tracts or interests, the conservation agency may consolidate these tracts and interests through the issuance of a compulsory pooling order, thereby allowing the single unit well to serve all tracts and interests within that drilling unit. Compulsory pooling protects the correlative rights of the owners of tracts, generally including fractional interests within such tracts that are too small to comprise a drilling unit.

Development occurs in accordance with a pre-ordained spacing and density pattern that usually follows survey boundaries. Accordingly, although there is a presumption that reservoirs are homogenous and drainage by a well will be radial, drilling units are ordinarily square or rectangular in shape, commonly consisting of 40, 80, 160, 320, and 640 acres. Older fields were often developed on five and ten acre spacing patterns.⁴ If a given reservoir is developed fully, the result is a uniform pattern of wells located on drilling units of uniform size and shape. In theory, spacing and density regulations limit the number of wells to those that are necessary to drain the reservoir efficiently and effectively, and both spacing and pooling protect correlative rights. Although certainly preferable to rule of capture development, the actual application of conservation regulations unfortunately seldom achieves these theoretical objectives.

In some states, spacing and pooling regulations are further supplemented by limiting production. In a few states, production from all wells is limited to allow each interest owner a fair opportunity to recover the oil and gas beneath individual tracts.⁵ This practice is based upon the highly questionable premise that each drilling unit contains the same amount of recoverable oil. In any event, however, for correlative rights to be protected in practice, other owners have to drill wells promptly. Thus, there is no guarantee that the protection of correlative rights will be achieved even in those few instances where the premise may be largely correct.

Under another form of production limit, wells are restricted to their maximum efficient rate of recovery (MER). In theory, a well’s MER is “the upper limit of production beyond which any increase will mean a decrease in ultimate recovery.”⁶ MER production limits, which are generally assigned on a field-wide basis, are based upon the questionable premise that all wells have the same MER.

⁴ See *Larsen v. Oil & Gas Conservation Comm’n*, 569 P.2d 87, 94 app. A (Wyo. 1977) (illustrating various spacing patterns on a map of North Rainbow Ranch Field).

⁵ See, e.g., *Wronski v. Sun Oil Co.*, 279 N.W.2d 564, 569–70 (Mich. Ct. App. 1979) (illustrating this form of regulation in the context of a conversion case).

⁶ See generally ROBERT E. SULLIVAN, *THE HANDBOOK OF OIL AND GAS LAW* § 165 (1955).

Yet another form of production limit curtails production of oil wells that produce high ratios of gas from a gas-cap expansion reservoir or high ratios of water from a water-drive reservoir.⁷ These limitations are imposed to preserve natural reservoir energy and thereby prevent underground waste. Some conservation agencies use this form of curtailment as a means of encouraging field-wide unitization.⁸

II. PROBLEMS WITH WELL-BY-WELL REGULATION

Unfortunately, these traditional conservation regulations addressing well numbers, well locations, and production are fraught with problems and often fail to achieve their theoretical objectives. For example, the agency may prescribe drilling units that are too small or too large or wells may be drilled in less than optimal locations for recovery efficiency. If too small, more wells are drilled than necessary, resulting in economic waste and perhaps underground waste. If too large, some hydrocarbons may not be recovered. The latter is usually less of a problem because the conservation agency can allow the drilling of additional "in fill" wells; however, the drilling of in-fill wells raises the correlative-rights issue of whether the drilling units should be preserved in their original size or "de-spaced" into smaller units.⁹

"Exception-location" wells are another problem. These are wells that are drilled or produced as exceptions to the normal well-spacing pattern. Often, exception-location wells can be drilled only after a separate regulatory proceeding. There are many reasons for exception-location wells. Due to surface topography or reservoir geology one location may be far preferable over another.¹⁰ An existing well may have been initially completed in another reservoir that was developed on a different well spacing pattern. To save money, the operator of the well may wish to re-complete the well in the subject reservoir as an exception-location well.¹¹ Or a well may have been legally located in contemplation of finding oil, but completed as a gas well.¹²

⁷ See, e.g., *Denver Producing & Ref. Co. v. State*, 184 P.2d 961, 161-62 (Okla. 1947) (illustrating this form of production limit).

⁸ An additional form of production limit is market demand prorationing, whereby production is not allowed to exceed reasonable market demand. See, e.g., *Railroad Comm'n v. Continental Oil Co.*, 157 S.W.2d 695 (Tex. Civ. App. 1941) (illustrating this form of production regulation). Federal authorization for market demand prorationing by the states was a principal reason for the formation of the Interstate Oil Compact Commission in 1935. Although still implemented in a few states, this form is largely of historical importance in the United States; however, the Organization of Petroleum Exporting Countries (OPEC) now engages in a somewhat similar activity by setting production quotas for member countries.

⁹ See, e.g., *Hystad v. Industrial Comm'n*, 389 N.W.2d 590, 594 (N.D. 1986).

¹⁰ See, e.g., *In re Gulf Oil Corp.*, 313 P.2d 1101, 1102-03 (Okla. 1957).

¹¹ See, e.g., *Exxon Corp. v. Railroad Comm'n*, 571 S.W.2d 497, 498-99 (Tex. 1978).

¹² The drilling unit for a gas well is ordinarily larger than the drilling unit for an oil well, because a gas well will commonly efficiently drain a larger area than an oil well. See, e.g., *Pattie v. Oil & Gas Conservation Comm'n*, 402 P.2d 596, 598 (Mont. 1965) (illustrating the difference in drilling unit size for an oil well and a gas well).

Exception-location wells are permitted to prevent waste, to protect correlative rights, or both. If an exception-location well is permitted by the conservation agency, neighboring landowners who have drilled their wells at the normal locations may present expert testimony on the need to limit the production from the proposed exception well to protect their property from unfair drainage. The exception-location applicant will most likely present expert testimony in rebuttal. These disputes further complicate the regulatory process and increase regulatory costs.

Another problem with a well-by-well regulatory approach is that the true nature of the typical oil and gas reservoir is largely ignored. Well spacing and density rules are grounded on three assumptions that are largely false: first, that oil and reservoirs are homogeneous; that is, they have the same characteristics throughout; second, that all wells completed in such a reservoir will drain in a radial pattern; and third, that, although drilling units are usually square or rectangular, the drainage pattern of one well will be fairly offset by the drainage pattern of neighboring wells so that each unit well will recover a fair share of hydrocarbons.

Reservoirs are typically heterogeneous. The typical reservoir has varying porosity and permeability throughout, varying thickness, and varying quantities and types of hydrocarbons. Nevertheless, relying upon the above three assumptions, the conservation agency, in administering a typical spacing and pooling regulatory regime, will usually treat all tracts the same. Thus, tracts having structural advantage (for example, tracts located above the apex of an anticline and above the thickest part of the reservoir) are treated the same as tracts having poor structural advantage (for example, tracts located on the edge of an anticline and above a thinner portion of the reservoir).¹³ The end result is often too many wells drilled at less than optimal locations that fail to drain the reservoir efficiently and fail to protect correlative rights adequately.

Other problems with a well-by-well regulatory approach arise from compulsory pooling practices. Although compulsory pooling is often effective in protecting the correlative rights of the owners of tracts that are too small to comprise a drilling unit and may be used to consolidate fractional interests in drilling units, it is far from a perfect way to achieve even these limited objectives. Compulsory pooling is based upon a well-by-well regulatory approach and conservation agency practices often fail to protect fully correlative rights. This occurs when some working interest owners who are unwilling to assume the risk of drilling simply speculate at the expense of those who have assumed the risk. Although they may be subjected to a risk penalty, or possibly even a loss of interest in a particular well, they lose no rights in neighboring drilling units, which can now be drilled at virtually no risk to the owners.

¹³ See, e.g., *Pickens v. Railroad Comm'n*, 387 S.W.2d 35, 38–43 (Tex. 1965).

The Oklahoma compulsory pooling practices better address the speculation problem within a drilling unit. All working-interest owners are required to participate at risk or assign their working-interest rights for consideration determined by the conservation agency. However, the pooling process itself is more involved and time-consuming, leading to high regulatory costs that are usually incurred on a drilling-unit basis. Commonly, Oklahoma regulatory practice enlarges a newly discovered field on a drilling unit basis by combining spacing and pooling into one proceeding. Due to land ownership patterns, this may often require a separate proceeding for almost every well in a field. Like in other states, working-interest owners holding interests in adjacent or nearby drilling units are not affected by pooling and can take a "risk-free ride" on the drilling party's well.

Certain Oklahoma conservation agency practices invite a different kind of speculation concerning the drilling of "in-fill" development wells. This scheme may unfold when a party seeking to acquire oil or gas reserves acquires an interest in a unit, usually a very small interest, from a participating working interest owner. The selling party may even reserve rights in the existing well bore. This purchased interest is ordinarily subject to the "non-consent" provision of the joint operating agreement¹⁴ or to the subsequent well provisions of the pooling order.¹⁵ In either case, any working interest owner may propose additional wells. Owners who refuse to participate in additional drilling are subject to the non-consent provisions of the pooling order, which may provide for relinquishment of their interest in the subsequent well, or the non-consent provisions of the joint operating agreement, which typically provide for a risk penalty ranging from 300 percent to 500 percent. If an additional well is proposed, many owners may refuse to participate, believing that the well would cause economic waste because it is not needed to prevent underground waste. Thanks to the helpful testimony of a retained petroleum engineer, however, the purchaser may be able to convince the conservation agency that an in-fill well is necessary. Although other working interest owners are likely to counter the applicant's testimony, the commission may often resolve any doubt in favor of drilling the in-fill well, which can be viewed as good for the local well-drilling and well-service economy. After securing a drilling permit, the applicant may drill a low-risk development well and, as a consequence, realize additional income from the unit by acquiring the relinquished interests under provisions of the prior pooling order or joint operating agreement. On the other hand, should other owners elect to

¹⁴ See, e.g., AMERICAN ASSOCIATION OF PETROLEUM LANDMEN FORM 610-1989 MODEL FORM OPERATING AGREEMENT, in ROCKY MOUNTAIN MINERAL LAW FOUNDATION, MINERAL LAW SERIES VOL. 1990, No. 2, OIL AND GAS JOINT OPERATING AGREEMENT 13-8 (1990).

¹⁵ See, e.g., *Texaco Producing Inc.*, Okla. Corp. Comm'n Order 350892 (Oct. 12, 1990), reprinted in FORMS MANUAL TO ACCOMPANY CASES AND MATERIALS ON OIL AND GAS LAW, Form # 6-2, art. 13 (West Group 4th ed. 2004).

participate in the well, the applicant may then decide not to drill the proposed well after all. Under this scheme, the purchasing speculator essentially wagers that it will acquire relinquished interests or gain additional revenues by way of non-consent penalties. Moreover, the in-fill well may actually drain reserves from the initial unit well, perhaps a high-risk wildcat well that the purchasing speculator did not participate in drilling. Unfortunately, absent compelling evidence that the in-fill well will cause economic waste while failing to prevent underground waste, this scheme is not easily thwarted.

The preceding discussion has endeavored to illustrate some of the problems with a well-by-well regulatory approach. A reader unfamiliar with conservation practices is cautioned not to assume that this discussion offers a summary of “normal” conservation regulatory practice. Indeed, another problem with traditional oil and gas conservation regulatory practices is a lack of uniformity from state to state.¹⁶ This lack of uniformity serves to further increase costs for the many operators that drill wells and produce oil and gas in more than one state.

For several decades, leading oil and gas economists have recognized the shortcomings of a well-by-well regulatory approach.¹⁷ Professor Stephen McDonald, while acknowledging that traditional spacing, pooling and prorationing regulations have been helpful, points out that these regulations have two serious defects:

First, they do not adequately protect correlative rights . . . In the ordinary situation where some wells in a reservoir have structural advantage or disadvantage depending on whether oil is driven toward or away from them by expanding gas or water, producers’ rights to the oil originally in place beneath their surface leases are not protected by allowing each well draining a tract of given size to produce at the same rate as every other in the reservoir as long as it can Second, by aiming at physical efficiency—or the prevention of physical waste in the language of the typical conservation statute—existing regulatory measures do not necessarily benefit the industry or society in every instance and certainly do not maximize the benefit we derive from our oil resources over an extended period of time.¹⁸

Professors Wallace Lovejoy and Paul Homan conclude that a well-by-well regulatory approach reduces but does not eliminate the drilling of unnecessary

¹⁶ For example, well spacing practices range from the establishing of drilling units for the entire reservoir upon initial discovery as is done in North Dakota, to establishing drilling units on a well-by-well basis prior to drilling as is typically done in Oklahoma, to establishing drilling units on a well-by-well basis after drilling as is typically done in New York.

¹⁷ See generally WALLACE F. LOVEJOY & PAUL T. HOMAN, ECONOMIC ASPECTS OF OIL CONSERVATION REGULATION (1967) [hereinafter LOVEJOY & HOMAN]; Stephen McDonald, *Unit Operation of Oil Reservoirs as an Instrument of Conservation*, 49 NOTRE DAME L. REV. 305, 308 (1973).

¹⁸ McDonald, *supra* note 18, at 308.

wells.¹⁹ They further conclude that development of reservoirs by numerous working interest owners acting on their own increases costs and decreases ultimate recovery.

III. THE ADVANTAGES OF EARLY UNITIZATION

Leading economists, including Professors McDonald, Lovejoy, and Homan, strongly support field-wide unit operations at an early stage of development, arguing that because self-interest would be unitized, the unit operator would determine the proper rates of production and investment without the need for extensive well-by-well regulatory oversight.²⁰

Early unitization would decrease drilling and operational costs because fewer wells would be drilled and there would be little need for production regulation. In turn, overall regulatory costs would be reduced for both interest owners and states. Unit operators would be free to make the most efficient use of the surface of the entire unitized acreage.²¹ The result would be less surface use overall, far fewer conflicts with surface owners, and fewer land-use²² and environmental concerns²³ because there would be fewer well bores, well locations, access roads, tank batteries, and gathering systems. Moreover, the unit operator could more easily and more fully utilize a variety of modern technologies, including 3-D seismic surveying and hydraulic fracturing, with less risk of trespass claims. Field-wide unitization would greatly reduce potential liability to third parties because there would be no owners of non-unitized tracts alleging damages from unit operations. Although the regulatory costs of achieving unitization may be high, overall regulatory costs should be much lower because well-by-well regulatory proceedings would be eliminated and there would be less need for regulatory oversight once unitization is achieved. Finally, because unitization regulatory practices are more uniform from state to state than other oil and gas conservation practices, the oil and gas industry would encounter more consistent and uniform regulatory treatment.²⁴

¹⁹ *Id.*

²⁰ LOVEJOY & HOMAN, *supra* note 18, at 74-81.

²¹ *Cf.* Mountain Fuel Supply Co. v. Smith, 471 F.2d 594, 596 (10th Cir. 1973) (concluding that a mineral developer relying on the common law right of surface use may not use the surface of leased acreage to develop other tracts) and Delhi Gas Pipeline Corp. v. Dixon, 737 S.W.2d 96, 97-98 (Tex. App. 1987) (recognizing that a unit operator may reasonably use the surface of all unitized acreage to develop a unit).

²² For a discussion of land-use issues, see generally Jeffrey R. Fiske & Ann E. Lane, *Urbanization of the Oil Patch: What Happens When They Pave Paradise and Put Up a Parking Lot?*, 49 ROCKY MTN. MIN. L. INST. 15-1 (2003); Bruce M. Kramer, *The Pit and the Pendulum: Local Governmental Regulation of Oil and Gas Activities Returns from the Grave*, 50th INST. ON OIL & GAS L. & TAX'N 4-1 (1999).

²³ For a discussion of environmental issues, see generally David E. Pierce, *Assessing Thirty Years of Federal Environmental Regulation of Upstream Oil and Gas Activities*, 50th INST. ON OIL & GAS L. & TAX'N 5-1 (1999).

²⁴ See Anderson & Smith, *supra* note 1, § 2.05 for further discussion of the advantages of early unitization.

Most producing states, excluding Texas,²⁵ have enacted compulsory unitization acts. Unlike compulsory pooling acts, however, a conservation agency's legal authority to unitize is commonly limited in two respects. First, most unitization acts require a significant percentage of voluntary agreement before the conservation agency may issue a compulsory unitization order.²⁶ Second, some unitization acts require a showing that unitization is necessary to allow for specific operations that require a coordinated effort, such as enhanced recovery or pressure maintenance operations.²⁷ Both of these limits make unitization harder to achieve, especially early in the life of a field. Moreover, the details of some unitization acts limit unitization to conducting secondary or enhanced recovery operations.

Postponing unitization until significant development has occurred and requiring a high threshold percentage of voluntary agreement to unitize invites strategic behavior that may harm the correlative rights of non-ratifying parties. These threshold percentages, which are based upon mineral ownership shares, not on the number of owners, range from sixty-three percent in Oklahoma²⁸ to eighty percent in Colorado,²⁹ Montana,³⁰ and Wyoming.³¹ These percentages must be separately met for both mineral owners and royalty owners. Achieving the required threshold of voluntary agreement can often be very difficult and usually gets harder to achieve as production matures.

Typically, the major hurdle to achieving these threshold percentages arises over the allocation of unit costs and production and not over the specific kind of unit operations. Self-interest causes each interest owner to argue for a high allocation of production. Given the heterogeneous nature of most oil and gas reservoirs, there is ample room for argument over the proper allocation. Moreover, each working interest owner who has already made substantial investments in primary recovery operations can be expected to argue for large investment credits in the unit—something that is not compatible with the self-interests of those who have made little or no investment in primary recovery operations.

²⁵ Although opposed by politically powerful interest groups, the need for unitization in Texas is readily apparent. *See generally* JACQUELINE L. WEAVER, UNITIZATION OF OIL AND GAS FIELDS IN TEXAS (1986); Paula C. Murray & Frank B. Cross, *The Case for a Texas Compulsory Unitization Statute*, 23 ST. MARY'S L.J. 1099 (1992).

²⁶ *See, e.g.*, N.D. CENT. CODE § 38-08-09.5 (Supp. 2003). An exception is the Alaska Act, which has no voluntary agreement threshold, but also has few privately owned mineral estates. ALASKA STAT. § 31.05.110 (Michie 1997). Another exception is Washington, which has no significant oil or gas production. WASH. REV. CODE ANN. § 78.52.330 (West 1996).

²⁷ *See, e.g.*, FLA. STAT. ANN. § 377.28 (West 1997).

²⁸ OKLA. STAT. ANN. tit. 52, § 287.5 (West 1991). Nevada, which does not yet have significant production, specifies a percentage threshold of 62.5%. NEV. REV. STAT. ANN. § 522.0834(1)(a) (Michie 1997).

²⁹ COL. REV. STAT. § 34-60-118 (1998).

³⁰ MONT. CODE ANN. § 82-11-207 (1997).

³¹ WYO. STAT. § 30-5-110 (Michie 1997). For good cause, this percentage can be reduced to seventy-five percent by special order of the conservation agency. *Id.*

In an effort to achieve threshold percentages, interest owners may consider multiple allocation proposals. Votes may be taken on many proposals. None may receive the necessary threshold of approval, but if one does, there is no assurance that the winning proposal would best protect correlative rights. Although the final allocation formula is supposed to protect correlative rights, and is subject to conservation agency approval on that basis, the conservation agency is more likely to be concerned about orderly development and preventing waste. Thus, once the threshold is achieved, the conservation agency is likely to approve the unitization as proposed.³²

The best solutions to these impediments to unitization are to reduce the threshold percentages³³ and to unitize at an earlier stage of operations—ideally at exploration.

Currently in the United States, exploratory unitization is available to lessees of federal public lands. Federal exploratory units may also include nearby privately-owned acreage if the acreage is subject to leases containing broad unitization clauses³⁴ or where the lessor of the acreage has otherwise consented to participate in an exploratory unit. The operational benefits are obvious. At the outset, initial seismic exploration can occur over the entire unitized area without concern for trespass. Moreover, the best well sites can be selected from a geological perspective without having to worry about leases that are nearing the end of their primary terms.

IV. EXPLORATORY UNITIZATION UNDER THE 2004 MODEL ACT

Under the 2004 Model Act's exploratory unitization provisions, domestic oil and gas operations may be conducted much like international operations, where operators acquire large acreage blocks from the host government to explore and develop. These provisions borrow from traditional compulsory unitization statutes, federal exploratory unitization practices, and international host government contracts. As with enhanced recovery units, all unit operations, including seismic surveying, drilling, or production upon a portion of the unit area, are deemed operations attributable to each separately owned tract in the unit area. However, unlike traditional enhanced recovery units, exploratory unit operations (EUOs), including production operations, hold lease interests only as to the geologic formations and depths included in the exploratory unit order. The portion of production allocated to individual tracts, or the proceeds of sale for that portion are deemed the property or income of the parties to whom or to whose credit that portion is allocated under the terms

³² This strategic behavior is illustrated in *Gilmore v. Oil & Gas Conservation Comm'n*, 642 P.2d 773, 774–76 (Wyo. 1982).

³³ See Anderson & Smith, *supra* note 1, at 2–77 to 2–85.

³⁴ See, e.g., *Amoco Prod. Co. v. Heimann*, 904 F.2d 1405 (10th Cir. 1990).

of the unit order.³⁵ In addition an exploratory unit receives the same statutory antitrust immunity as other units.³⁶

Under the Model Act, a conservation agency may entertain compulsory exploratory unitization upon the application of a working-interest owner. The agency is obliged to issue an order requiring EUOs if it finds that the proposed operations are reasonably necessary “to prevent waste, to encourage reasonable, orderly, effective, and efficient exploration and potential development, to avoid the drilling of potentially unnecessary wells, and to protect correlative rights” and finds that the “estimated costs . . . are reasonable in light of the risk that exploration may prove to be unsuccessful and in light of the potential rewards of successful exploration and discovery of oil or gas.”³⁷ Of course, the orderly exploration of an entire prospect area should ordinarily be justified as a means of preventing economic waste.

An optional bracketed provision allows the legislature to establish a maximum unit size.³⁸ Another optional bracketed provision allows the legislature to fix a minimum depth for EUOs. These options may prove to be politically necessary in the face of possible opposition to exploratory unitization from small operators.³⁹

An order for exploratory unitization should contain many of the same provisions included in a traditional compulsory unitization order. Specifically, the Model Act requires a description of the area, including a description of the geologic formations, and a description of the minimum and maximum depths of EUOs. An order should also outline the various phases of EUOs, including the contemplated plans for exploration, appraisal, development, production, and abandonment. The order also must contain a provision protecting correlative rights that allocates to each separately owned tract, in the unit area, a just and equitable share of production; a provision for credits and charges as an adjustment among owners in the unit area for their interest in geological studies, seismic data, or other information that contributes to EUOs; and a provision allocating the costs of EUOs among working interest owners, including how to treat those owners who do not participate. Because exploratory units may often be formed before any reservoir boundaries or characteristics are known, the order must also address compensating an owner whose interest is ultimately excluded from the unit where that interest is determined to be non-productive. For similar reasons, the order must address the possible creation of sub-units if more than one reservoir is discovered and developed. The order would designate a unit operator to supervise and conduct EUOs; establish a voting mechanism for working interest owners that

³⁵ MODEL OIL AND GAS CONSERVATION ACT § 27 (2004).

³⁶ *Id.* at § 28.

³⁷ *Id.* at § 22.

³⁸ *Id.*

³⁹ *Id.* at § 23.

corresponds to the percentage of the costs of EUOs chargeable to each owner, which may be subject to change as the unit is modified; and require a passmark vote to approve operations following the initial exploration phase. To assure diligence, the order would set a time, subject to any *force majeure* events specified in the order, when the exploratory, appraisal, and development phases must commence and be completed and a time when the productive phase is to commence or the unit is to be dissolved. As is customary in the United States, the production phase extends for so long as oil or gas is produced in paying quantities plus sufficient time thereafter for abandonment of EUOs.⁴⁰

In the event of competing applications, the conservation agency would select the plan and unit operator that best serves the public interest of encouraging orderly exploration and development, preventing waste, and protecting correlative rights. Factors in making this choice might include a comparison of the proposed operations and the financial and technical ability of the applicant to carry them out. The experience of the applicant and the extent of the applicant's ownership interest would also affect the choice.

The Model Act wisely leaves many details to regulations or unit order provisions. For example, the order should specify the geologic studies and seismic surveys to be conducted on the unit during the exploration phase together with a good-faith estimate of their cost. Any portion of the area not studied and surveyed as proposed and approved should be automatically deleted from the unit.

Oklahoma's compulsory pooling practices could serve as a framework for the treatment of other working interest owners, including unleased mineral interest owners. Under the typical Oklahoma compulsory pooling order, working-interest owners are given the option of participating in a well on an acreage allocation basis. Under exploratory unitization, owners could be given a similar option. As under Oklahoma compulsory pooling, if an interest owner declines to participate, that owner might be forced to relinquish its interest to the participating parties for the duration of EUOs. Non-participating working-interest owners might be compensated for the speculative value of their interests, again as is done under Oklahoma compulsory pooling, subject to any reasonable royalties set forth in an underlying lease or other instrument. Unleased mineral owners could be allowed to participate or elect to take compensation in the form of cash, royalty, or both.

Upon completion of the exploration phase, working-interest owners could elect to release the unit acreage, thereby terminating the unit, or all or some could apply to extend the unit, or portion thereof, by proposing an appraisal phase. The appraisal phase would permit the perpetuation of that portion of the unit, which, based upon information gathered in the exploration phase, appears

⁴⁰ *Id.* at § 22.

likely to contain a common reservoir plus a reasonable buffer zone. Based upon the exploration information, which would be shared with the conservation agency and interested parties but would otherwise be confidential, the operator could propose a drilling plan for the targeted reservoir. Appraisal wells could be drilled at the locations within the unit that would best assist in defining and assessing the reservoir, rather than at locations required to perpetuate leases or to comply with well spacing and density regulations. If these appraisal operations confirmed the existence of a reservoir that could be profitably developed, optimum development of the field could then occur in accordance with sound geology, engineering, and economic principles without regard to lease boundaries or lease termination dates.

In the event of competing plans for any phase where none of the plans could achieve the required passmark vote specified in the unit agreement, the competing applications could be evaluated by the conservation agency. The agency could select the best plan in light of the public interest. An underfunded conservation agency might hire an independent consultant to evaluate all plans. By regulation, the costs of these evaluations might be charged to the successful unit applicant who could then be permitted to recover these costs from other participating working-interest owners as a unit expense. Under this regulatory approach all of the benefits of early unitization of newly discovered fields would be achieved, as well as the additional benefit of more efficient exploration. Moreover, the participants would have the exclusive opportunity to exploit their discovery.

Because of the possibility of additional drilling and other operations, those who elect to participate in the exploration phase would be required to execute a unit agreement. Before a unit order could become effective, the agreement would require the ratification of a minimum percentage of owners and royalty owners, based upon ownership interests.⁴¹ Under the Model Act, the unit agreement is subordinate to the unit order and to an amended order. An amended unit order is subject to the same conditions as the original order, except that the approval of the amendment by way of an amended unit agreement is not required of royalty interest owners whose interests are free of cost if the amendment affects only the rights and interests of the cost-bearing owners. Moreover, and if the amendment is necessary to protect correlative rights or merely modifies the specific operations in any phase of the EUOs, no approval of the amendment by owners and royalty interest owners is required.⁴² In addition, the conservation agency may dissolve a unit upon its

⁴¹ *Id.* at § 24.

⁴² *Id.* at §§ 24, 25.

own motion or upon the application by an owner for good cause, including the failure of the owners to diligently prosecute any phase of the EUOs.⁴³

As with any unitization, the most difficult issue to resolve is likely to be the allocation of costs and production. In federal exploratory units, the initial unit area is based upon geological or geophysical inferences that the acreage may overlie a common reservoir. But only the specially designated "participating area"⁴⁴ within the unit shares in production. The participating area is established by assigning certain unit acreage to a well, with some consideration given to the size of the standard drilling unit established for the reservoir. As additional wells are drilled, the participating area is expanded to encompass additional acreage; however, the unit area is automatically contracted to the developed acreage (the participating area) five years after the discovery of oil or gas in paying quantities. Thus, a federal exploratory unit contemplates a pattern of wells similar to that achieved under the traditional well-by-well regulatory approach, which may result in more wells being drilled than are necessary for the prevention of underground waste. The Model Act's exploratory unitization provisions do not follow this approach. Under the Model Act, development operations would be undertaken to optimize production and prevent waste. Since all owners within the unitized area share in any production, the drilling of a well solely to protect correlative rights is unnecessary.

Specifically, development wells would be drilled as needed to achieve maximum efficient recovery, not as needed to satisfy some uniform drilling-unit pattern of development. Thus, all tracts and interests within the development unit that are believed to overlie the common reservoir would share in production, initially on an acreage basis. This should be fair since the boundaries of a development unit would be drawn on the basis of detailed seismic data collected in the exploration phase that revealed the likely existence of a common reservoir.

The Model Act recognizes the potential need to modify unit boundaries as additional drilling and more detailed follow-up seismic data demonstrate that the boundaries were incorrectly drawn. Accordingly, to protect correlative rights, the allocation formula may have to be modified based upon particular reservoir characteristics. Contractual modifications to the allocation formula approved by the conservation agency could be permitted among consenting parties. For example, some working-interest owners might contract for a different allocation of costs or production among themselves, subject to the right of noncontracting parties to be governed by the default rules.

⁴³ *Id.* at § 26.

⁴⁴ 43 C.F.R. § 3180.0-5. Depending upon the pattern of development within a unit, there can be two or more separate participating areas in a federal exploratory unit.

V. CONCLUSION

We realize that myriad property, contractual, and regulatory issues will arise under the 2004 Model Act. A thorough analysis of such issues and potential solutions is beyond the scope of this essay. We hope, however, that this brief essay has provided a realistic view of the benefits that will flow both to individual states and the nation as a whole from legislation that authorizes compulsory unitization at the exploratory and early developmental stage of oil and gas operations.

APPENDIX

E

Appendix E

**Tentative Agenda for Wyoming
Information Technology Meeting
Casper, Wyoming
August 28th – 29th, 2007**

August 29

(Events at the Commission Hearing Room)

9:00 – 10:00 a.m.	Demonstration of new Web-based reporting system-Web Services Rick Marvel
10:00 – 11:30a.m	Roundtable Discussion-What other states are doing for reporting.
11:45 – 1:00	Lunch- The 3 Crowns
1:30 – 2:00p.m.	Presentation-Trans forMagic
2:00 –2:30p.m.	Discussion with users of the Wyoming Web system
2:30 - 3:00p.m.	Software Development – Rick Marvel
3:00 – 4:00p.m.	Demonstration of WY system with the Web-Rick Marvel
4:00 – 5:00p.m.	Roundtable Discussion of software development
5:30-	Closing Reception and Dinner -Hosted by IHS

State of Wyoming - Oil & Gas Conservation Commission
P.O. Box 2640 - 2211 King Blvd.
Casper, Wyoming 82602
307-234-7147

August 29, 2007

State IT Sharing Meeting

Attendees

Name	E-Mail Address	State	Position
Michael Loflin	mloflin@ogb.state.wy.us	Mississippi	IT
Mack McGillivray	mack.mcgillivray@state.sd.us	South Dakota	Senior Geologist
Lloyd Faver	l.faver@occemail.com	Oklahoma	IT
Sharon Rogan	sharon@spatialsolutionsgroup.com	Colorado	GIS Consultant
Thom Kerr	thom.kerr@state.co.us	Colorado	Data Systems Manager
Rick Marvel	rmarve@state.wy.us	Wyoming	Engineering Manager
Richard Sims	rsims@ogb.state.ms.us	Mississippi	Lead Systems Administrator
Jim Lindholm	jlinholm@nd.gov	North Dakota	IT Administrator
Dan Pearson	dan.pearson@aogc.state.ar.us	Arkansas	IT Administrator
Jim Gazewood	jim.gazewood@blm.gov	Wyoming	Petroleum Engineer/
Bethann Rome	brome@transformagic.com	Industry	CEO
John Rome	jrome@transformagic.com	Industry	CIO
Jim Stanley	jim.stanley@ihsenergy.com	Colorado	Consultant
Larry Claypool	larry_claypool@blm.gov	Wyoming	PE - Chief, BLM - RMG
Dave Hutton	dhutto@state.wy.us	Wyoming	IT
Rob Meyer	rmeyer2@state.wy.us	Wyoming	IT
Amy Wright	amy.wright@iogcc.state.ok.us	Oklahoma	Federal Projects Manager

APPENDIX

F

Appendix F

Office of Geological Survey Issues Statements

1. The dependency on other agencies (Attorney General, Department of Natural Resources, Department of Information Technology, Department of Management and Budget) is an ongoing issue that affects the timeliness of permits and contracts, the protection of natural resources, and the ability to develop and maintain the quality and integrity of OGS data.
2. The impending retirements of the OGS workforce (60% over the next 5to8 years) and the current management structure does not provide for adequate management oversight, consistency, coordination or the ability to adequately address emerging issues, which will result in a loss of expertise and institutional knowledge and a negative impact on the environment, natural resources and our customers.
3. The lack of knowledge and understanding of facts by certain customers and groups, changing demographics, and the dissemination of inaccurate information by others reduces our ability to adequately direct our resources toward protecting the environment for our customers.
4. The lack of quality, accessibility and completeness of OGS data is leading to the production of inaccurate information, thereby leading to inefficiencies and a lack of dependable information for both our internal and external customers.
5. While there is an overall adequate budget available, continuing spending constraints have resulted in an inability to provide adequate resources which reduces our ability to protect the environment, achieve compliance, protect property rights and, ultimately, reduces OGS's effectiveness and efficiency.

IOGCC, Michigan OGS

Program/Activity Business Plan Elements

Program Issue Statements

1. .

Program Purpose Statement

The purpose of the Mineral Wells Program is to provide site and record evaluation, information, compliance consultation and escalated enforcement services to mineral well permittees, property and mineral owners, federal, state and local governmental agencies, environmental groups and the general public so they can develop and assess the conservation of resources and contribute to the protection of surface and mineral interests, prevent pollution and evaluate compliance with laws and regulations.

Key Outcome Measures

1. % of violations identified that were resolved or being remediated
2. % of enforcement cases that are brought into compliance

Activity 1: Inspections

Activity Purpose Statement

The purpose of the Inspection Activity is to provide site and record evaluation, information (well operation, geological, environmental), compliance consultation and notification services to mineral well permittees, property and mineral owners, federal, state and local governmental agencies, environmental groups and the general public so they can assess the conservation of resources and protect their surface and mineral rights, prevent pollution, promote the development of resources and evaluate compliance with laws and regulations (Natural Resources and Environmental Protection Act).

Services

Mineral Wells Site Inspections
Information (well, operation, geological and environmental)
Notices of Inspection
Compliance Information
Notices of non-compliance

Family of Measures

Outcome Measures:

1. % of inspections completed within scheduled time frame
2. % of records amended to achieve protection of property, natural resources, the environment and public health
3. Ratio of total inspections to total wells
4. Ratio of inspections identifying a violation to total inspections
5. **% of violations identified that were resolved or being remediated**

Output Measures:

1. # of inspections completed
2. # of violations identified
3. # of violations resolved
4. # of Notices of Non-compliance issued

Demand Measures:

1. # of mineral well operations

Efficiency Measures:

1. Dollar cost or expenditure per mineral well operation inspection conducted

Activity 2: Escalated Enforcement

The purpose of the Escalated Enforcement Activity is to provide escalated compliance action services to mineral well permittees so they can achieve compliance with the Natural Resources and Environmental Protection Act (NREPA) thereby conserving resources and protecting property, natural resources, the environment, and the public's health and safety; and, to provide notification services to federal, state and local governmental agencies so they can take appropriate actions.

Services

Referral Packages

Supervisor of Mineral Well Orders

Opportunity to Show Compliance Meetings

Family of Measures

Outcome Measures:

1. % of enforcement cases that are brought into compliance
2. % of total cases referred to outside agencies

Output Measures:

1. # of enforcement cases processed
2. # of enforcement cases referred to “Compliance and Enforcement”
3. # of enforcement cases resolved or ongoing
4. # of enforcement cases referred to outside agencies

Demand Measures:

1. # of enforcement cases received and expected to be received

Efficiency Measures:

1. Dollar cost or expenditure per enforcement case processed

IOGCC, Michigan OGS Program/Activity Business Plan Elements

Program Issue Statements

2. .

Program Purpose Statement

The purpose of the Oil and Gas Program is to provide regulatory oversight, compliance consultation and notification, permit decisions, data collection and dissemination, resource conservation, pollution remediation and prevention services to the oil and gas industry, property and mineral owners, environmental groups, federal, state and local governmental agencies, and the general public so they can: assess and promote the development and the conservation of energy resources; obtain geological data; implement pollution prevention; evaluate their compliance with laws and regulations (Natural

Resources and Environmental Protection Act); and contribute to the protection of property (surface and mineral interests), natural resources, the environment and public health.

Key Outcome Measures

3. % of permit decisions made within 50 days
4. % of required production records received
5. % of violations identified that were resolved or being remediated

Activity 1: Technical Review and Permits

Activity Purpose Statement

The purpose of the Technical Review and Permits Activity is to provide permit decisions, supervisor's orders and information services to oil and gas applicants, property and mineral owners, federal, state and local governmental agencies, environmental groups and the general public so they can drill wells, evaluate the impact of proposed and issued permits, develop and conserve energy resources, and contribute to the protection of property, natural resources, the environment and public health.

Services

Drill and Operate Permits
Change of Well Status Permits
Plugging Permits
Deepening Permits
Supervisor's Orders
Oil and Gas Information

Family of Measures

Outcome Measures:

1. % of permit decisions made within 50 days
2. % of permit applications amended to achieve protection of property, natural resources, the environment and public health
3. % of permit records updated within last three years
4. % of supervisor's orders issued within X timeframe
5. % of administrative exceptions (Rule 303) issued within X timeframe

Output Measures:

1. # of permit decisions made
2. # of supervisor's orders issued

3. # of application inspections conducted
4. # of public meetings attended
5. # of administrative spacing exception decisions made
6. # of information requests responded to

Demand Measures:

1. # of applications submitted and expected
2. # of petitions received
3. # of administrative spacing exception requests submitted and expected
4. # of website inquiries received and expected

Efficiency Measures:

1. Dollar cost or expenditure per permit decision made

Activity 2: Production and Records

Activity Purpose Statement

The purpose of the Production and Records Activity is to provide supervisor proration orders and evaluations, and information (geological, historic oil & gas production, reservoir data, well construction, and well completion history) services to oil and gas applicants, property and mineral owners, federal, state and local governmental agencies, and the general public so they can conserve energy resources, protect mineral rights, encourage exploration, standardize exploration practices, and verify oil & gas production tax and royalty payments.

Services

Information (geological, historic oil and gas production reservoir, well construction, well completion history)
Supervisor Proration Orders
Proration Evaluations

Family of Measures

Outcome Measures:

3. Ratio of the drilling records received to new wells drilled
4. **% of required production records received**
5. % of records amended to achieve protection of property, natural resources, the environment and public health

Output Measures:

5. # of drilling records added to database
6. # of production records recorded
7. # of records corrected
8. # of supervisor's proration orders issued
9. # of proration evaluations completed
10. # of information requests responded to

Demand Measures:

2. # of new wells drilled and expected to be drilled
3. # of producing wells
4. # of petitions for proration hearings submitted and expected
5. # of information requests received and expected
6. # of website inquiries received and anticipated

Efficiency Measures:

2. Dollar cost or expenditure per geological and production record maintained

Activity 3: Inspections**Activity Purpose Statement**

The purpose of the Inspection Activity is to provide site and record evaluation, information (well operation, geological, environmental), compliance consultation and notification services to oil and gas permittees, property and mineral owners, federal, state and local governmental agencies, environmental groups and the general public so they can assess the conservation of resources and protect their surface and mineral rights, prevent pollution, promote the development of energy resources and evaluate their compliance with laws and regulations (Natural Resources and Environmental Protection Act).

Services

Inspections of Oil, Gas, and Related Wells; and Associated Facilities
Information (well, operation, geological, and environmental)
Notices of Inspection
Compliance Information
Notices of Non-compliance

Family of Measures

Outcome Measures:

6. % of inspections completed within scheduled time frames
7. % of records amended to achieve protection of property, natural resources, the environment and public health
8. Ratio of total inspections to total wells
9. Ratio of inspections identifying a violation to total inspections
- 10. % of violations identified that were resolved or being remediated**

Output Measures:

5. # of oil and gas operations inspections conducted
6. # of violation identified
7. # of violations resolved
8. # of Notices of Non-Compliance issued

Demand Measures:

2. # of oil and gas operations

Efficiency Measures:

1. Dollar cost or expenditure per oil and gas operation inspection

IOGCC, Michigan OGS

Program/Activity Business Plan Elements

Program Issue Statements

3. .

Program Purpose Statement

The purpose of the Compliance and Enforcement Program is to provide escalated enforcement actions, consultation, and notification, well plugging, pollution mitigation and reclamation services to the oil and gas industry, property owners, environmental groups, federal, state and local governmental agencies, and the general public so they can benefit from the protection of the natural resources, the environment, and public health and safety.

Key Outcome Measures

6. % of enforcement cases that are brought into compliance
7. % of wells removed (plugged and/or site restored) from the orphan well list since program inception

Activity 1: Escalated Enforcement

The purpose of the Escalated Enforcement Activity is to provide escalated compliance services to oil and gas permittees so they can achieve compliance with the Natural Resources and Environmental Protection Act (NREPA) thereby conserving energy resources and protecting property, natural resources, the environment, and public health and safety; and, to provide notification services to federal, state and local governmental agencies so they can take appropriate actions.

Services

Enforcement Referral Letters (to permittees)
Enforcement Referral Packages (for escalated enforcement- Attorney General and Office of Criminal Investigation)
Enforcement Orders
Notices of Violation
Notices of Violation Hearings

Family of Measures

Outcome Measures:

6. % of enforcement cases that are brought into compliance
7. % of total enforcement cases referred to outside agencies

Output Measures:

11. # of enforcement cases processed
12. # of enforcement cases resolved or in remediation process
13. # of enforcement cases referred to outside agencies
14. # of total enforcement cases referred to “Compliance and Enforcement”

Demand Measures:

7. # of enforcement cases received and expected

Efficiency Measures:

3. Dollar cost or expenditure per enforcement case processed

Activity 2: Orphan Wells

Activity Purpose Statement

The purpose of the Orphan Wells Activity is to provide well plugging, site clean up and reclamation services to property owners, the oil and gas industry, environmental groups, federal, state and local governmental agencies, and the general public so they can have a safer and more healthy life and benefit from the return of the land to useful condition.

Services

Site Restorations
Orphan Well Annual Legislative Report
Orphan Well Prioritization Reports
Salvage Sales (of abandoned equipment and infrastructure)
Well Permit Transfers (adoptions)
Plugged Wells

Family of Measures

Outcome Measures:

1. **% of wells removed (plugged and/or site restored) from the orphan well list since program inception**
2. % of priority one orphan wells plugged since program inception

Output Measures:

1. # of priority one wells plugged since program inception
2. # of priority one wells plugged within the last year
3. # of orphan well permits transferred
4. # of sites removed from list within the last year
5. # of sites removed from list since program inception
6. # of dollars recovered from salvage

Demand Measures:

1. # of well evaluations/determinations received and expected
2. # of orphan wells classified as priority one
3. # of orphan wells

Efficiency Measures:

1. Average dollar cost or expenditure per well plugged
2. Average dollar cost or expenditure per priority one well plugged

3. Average dollar cost or expenditure per priority two well plugged
4. Average dollar cost or expenditure per well site restoration

Michigan Performance Measurement Assistance ATTENDANCE SHEET DATE: <u>February 7, 2005 (Morning)</u> TITLE OF PROGRAM: <u>Orientation & Workshop Review</u>			
X	Name (Please Print)	Work Phone	E-Mail Address
	Steve Wilson	517-242-1542	wilsonse@michigan.gov
	Ray Vugrinovich	517-242-1532	vugrinov@michigan.gov
	Lou Schineman	517-241-1531	schineml@michigan.gov
	Tom Godbold	517-241-1545	godboldt@michigan.gov
	Mike Bricker	517-241-1504	brickerm@michigan.gov
	Tom Wellman	517-241-1530	wellmant@michigan.gov
	Larry Hartwig	335-1310	hartwigl@michigan.gov
	Peg McComb-Elowski	517-241-1566	elowskip@michigan.gov
	Walt Danyluk	335-6253	danylukw@michigan.gov
	Rick Henderson	231-775-3960 x -6340	hendersr@michigan.gov
	Harold Fitch	517-241-1548	fitchh@michigan.gov
	Joe Maki	906-346-8563	makijr@michigan.gov
	Doug Daniels	269-567-3521	danieldl@michigan.gov

Michigan Performance Measurement Assistance			
ATTENDANCE SHEET			
Date: <u>February 7, 2005 (Afternoon)</u>			
TITLE OF PROGRAM: <u>Issue Statements</u>			
X	Name (Please Print)	Work Phone	E-Mail Address
1	Peg McComb-Elowski		
2	Mike Bricker		
3	Hal Fitch		
4	Tom Godbold		
5	Walt Danyluk		
6	Rick Henderson		
7	Tom Wellman		
8	Steve Wilson		
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Michigan Performance Measurement Assistance ATTENDANCE SHEET DATE: <u>February 8, 2005</u> TITLE OF PROGRAM; <u>Oil & Gas Breakout</u>			
X	Name (Please Print)	Work Phone	E-Mail Address
1	Peg McComb-Elowski		
2	Tom Wellman		
3	Walt Danyluk		
4	Tom Godbold		
5	Hal Fitch		
6	Mike Bricker		
7	Tom Wellman		
8	Paul Jankowski	517-335-6387	jankowsp@michigan.gov
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Michigan Performance Measurement Assistance ATTENDANCE SHEET DATE: <u>February 9, 2005</u> TITLE OF PROGRAM; <u>Inspection & Enforcement</u>			
X	Name (Please Print)	Work Phone	E-Mail Address
1	Mike Bricker		
2	Tom Godbold		
3	Rick Henderson		
4	Peg McComb-Elowski		
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Michigan Performance Measurement Assistance ATTENDANCE SHEET DATE: <u>February 10, 2005</u> TITLE OF PROGRAM; <u>PMW</u>			
X	Name (Please Print)	Work Phone	E-Mail Address
1	Douglas Daniels	269-567-3621	danieldl@michigan.gov
2	Steve Wilson	517-241-1542	wilsonse@michigan.gov
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4	Ray Vugrinovich	517-241-1532	vurginov@michigan.gov
5	Tom Godbold	517-241-1545	goldboldt@michigan.gov
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Michigan Performance Measurement Assistance ATTENDANCE SHEET DATE: <u>February 11, 2005</u> TITLE OF PROGRAM: <u>Meeting Wrap-Up</u>			
X	Name (Please Print)	Work Phone	E-Mail Address
1	Linda Sandborn	517-241-1548	
2	Hal Fitch	517-241-1548	
3	Tom Godbold	517-241-1545	
4	Peg McComb-Elowski	517-241-1566	
5	Tom Wellman	517-241-1530	
6	Walt Danyluk	335-6253	
7	Steve Wilson	517-241-1542	
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APPENDIX

G

THE DEFINITION

This half century-old technology is used in oil and natural gas production and allows trapped oil or natural gas to move freely from rock pores to a producing well that can bring the oil or gas to the surface.

In order to improve or maximize the flow of fluids many pre-existing fractures and flow pathways within the well are connected in the reservoir rock with a larger fracture. This larger, man-made fracture starts at the well and extends several hundred feet out into the reservoir rock.

THE PROCESS

- 1 A fluid is pumped down the well at a high-pressure for a short period of time (hours) to create the hydraulic fracture. The high-pressure fluid is usually water with specialty high-viscosity fluid additives.
- 2 A propping agent, usually sand carried by the high-viscosity additives, is pumped into the fractures to keep them from closing when the pumping pressure is released.
- 3 The high-viscosity fluid becomes a lower viscosity fluid after a short period of time.
- 4 The injected water and the now low-viscosity fluids travel back through the man-made fracture to the well and up to the surface.

ABOUT IOGCC

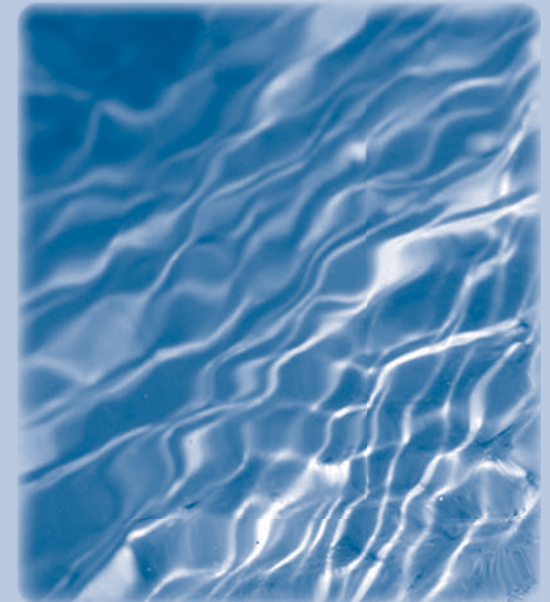
The Interstate Oil and Gas Compact Commission (IOGCC) represents the governors of 37 states — 30 member and seven associate states — that produce virtually all the domestic oil and natural gas. Seven international affiliates have been accepted into the organization, giving the IOGCC a voice in global energy affairs. The organization's mission is to champion the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety and the environment.



Interstate Oil and Gas Compact Commission

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HYDRAULIC FRACTURING



A SAFE AND ENVIRONMENTALLY SOUND WAY TO MAXIMIZE OUR NATION'S NATURAL RESOURCES

THE ISSUE

Despite any credible evidence, concerns were raised about the environmental impacts of hydraulic fracturing, a process used to increase production of oil and natural gas. Since the process emerged more than 50 years ago, state agencies have developed an impressive record of regulatory success. In fact, there has not been a single incident of hydraulic fracturing damaging a potential source of drinking water.

However, the effectiveness of state programs was challenged by the U.S. Environmental Protection Agency (EPA) and a full scale study was launched funded by federal tax dollars.

THE STUDY

EPA completed its study of the possible impacts of hydraulic fracturing on underground sources of drinking water (USDWs) in 2004.

The goal of the study was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids.

The EPA researched over 200 peer-reviewed publications, interviewed approximately 50 employees from state or local government agencies and communicated with approximately 40 citizens who were concerned that hydraulic fracturing impacted their drinking water wells. The agency searched for confirmed incidents of drinking water well damage, thoroughly reviewed the information collected and concluded that

THE OUTCOME

the injection of hydraulic fracturing fluids poses little or no threat to USDWs. This study confirms the success of effective state programs.

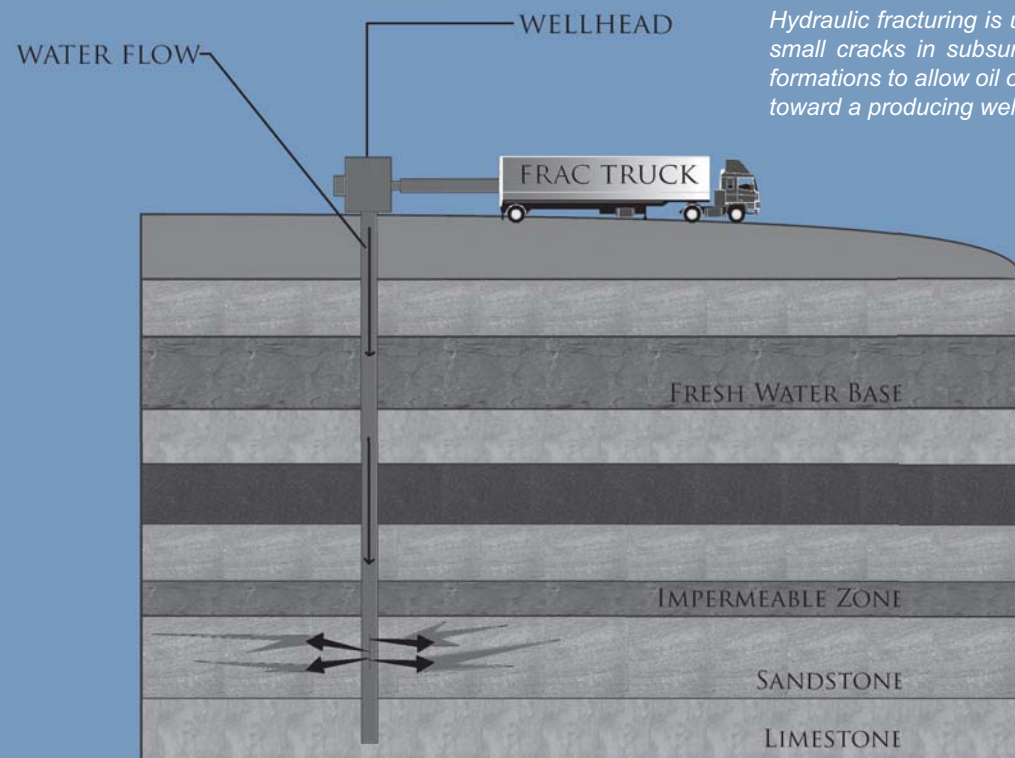
EPA found no confirmed cases linked to fracturing fluid injection or subsequent underground movement of fracturing fluids.

Specifically, according to the EPA final report, no hazardous constituents were used in fracturing fluids, and hydraulic fracturing did not result in creating a path for fluids to move between isolated formations. Reported incidents of water quality

degradation were attributed to other, more plausible causes, the EPA found.

Although thousands of wells are fractured annually, EPA did not find a single incident of the contamination of drinking water wells by hydraulic fracturing fluid injection.

Properly regulated, hydraulic fracturing is a safe and environmentally sound way to maximize and conserve our nation's natural resources.



APPENDIX

H



PETROLEUM PROFESSIONALS

Blue Ribbon Task Force: A Follow Up Report

Interstate Oil and Gas Compact Commission
January 2007

Governor John Hoeven



Foreword

Oil and natural gas resources found domestically continue to be the key to the nation's energy and national security. However, without qualified petroleum professionals to fill open positions, these valuable resources may not be fully maximized.

The following report, written by IOGCC Chairman Gov. John Hoeven of North Dakota, provides current information about the status of a manpower shortage facing the domestic petroleum industry. In addition, the report evaluates the efforts of state governments, the federal government and industry in solving the problem.

The IOGCC would like to thank Gov. Hoeven for his commitment to this important issue. Because of his outstanding leadership and the work of his Blue Ribbon Task Force to develop a comprehensive solution to the dilemma, the nation has finally taken steps to alleviate the problem. More needs to be done, and the IOGCC calls on all stakeholders to recommit to this effort.

Christine Hansen
IOGCC executive director



INTRODUCTION

The story of our nation's petroleum industry is an exciting tale of ingenuity and prosperity. In 1859, Edwin Drake struck oil in Titusville, Pennsylvania. That first well drilled specifically for oil was commercially successful and the world was changed forever.

Today, oil and natural gas drive the world economy and provide most of the energy necessary to live our daily lives. The petroleum industry in America generates direct revenue for state and federal governments, as well as providing jobs for citizens. Petroleum has become a daily necessity and a matter of national security.

Today the industry employs sophisticated technologies to locate and recover oil and natural gas from elusive reserves previously unattainable and to do so in an environmentally friendly fashion. The demand for petroleum resources has spurred the development of enormous technological advances and those technologies, in turn, have resulted in advances beyond the petroleum industry itself.

This story of success was written by numerous geoscientists including geologists, geophysicists, chemists and engineers, as well as skilled technicians of every kind who have developed the means to find and recover these precious resources. New successes are daily being discovered by petroleum scientists using horizontal drilling and ultra-deep water drilling.

Several years ago, it became apparent to many industry, professional and government leaders that there was a shortage in the numbers of these professionals and that the situation was growing more acute. The

IOGCC first published a study profiling the issue.

I then created a Blue Ribbon Task Force to further investigate and make recommendations for action.

The findings were bleak. Not only had the bust cycle of the eighties caused an unprecedented loss of the core workforce, but the industry was facing an aging workforce. At the same time, universities were seeing an alarming decline in enrollment for petroleum specific degrees, causing some to close those programs.

While technology had made the workforce more efficient, it did not completely compensate for the need for core talent. This became especially clear as a boom cycle began to emerge and the industry found it difficult to ramp up to meet the demand. The task force recognized that the outcome of the next chapter in the petroleum story would not only rest in the hands of industry, but also depend upon the support of both the state and federal governments.

The task force issued its final recommendations in 2003. This report seeks to shine a light on the current state of the domestic petroleum industry, the status of the recommendations toward a more robust public and private partnership, and the work that must still be addressed to sustain and strengthen the domestic industry. The progress is encouraging.



A HISTORICAL PERSPECTIVE

Although Native Americans had many uses for crude oil, white settlers before the 1850s generally regarded petroleum as the unwelcome byproduct of salt wells, sometimes causing those wells to be abandoned. Sometimes the oil was bottled and sold as medicine. Sometimes it was thickened with flour and used to grease wagon wheels and saw mill machinery. It was too smoky and odoriferous for use as lamp oil.

But, by 1840, sperm whales were nearly extinct and the Industrial Revolution was in full steam. The emerging new economy demanded new, inexpensive sources of fuel and lubricants. Abraham Gesner developed a method for extracting oil from coal to make kerosene and by 1859, more than 50 companies in the United States were manufacturing kerosene from coal. Samuel Kier, who bottled and sold crude oil as medicine from his father's salt wells, began to distill it into lamp fuel, a product he called carbon oil. He built a refinery with a five-gallon still in Pittsburgh. In 1853, the Dartmouth chemistry department, in what might possibly be the industry's first research program, examined a bottle of medicinal petroleum and concluded that it was very valuable with great potential for meeting the nation's fuel needs. By 1858, carbon oil was quickly replacing other dangerous and more expensive lamp fuels. Petroleum from northwestern Pennsylvania became the chosen product. Arguably the first boom cycle in the industry occurred as demand for oil drove the price from 75 cents to \$2 a gallon.

At first, the fledgling industry adapted techniques employed by mining technology for finding underground sources of water or salt. As the volume of activity grew, professionals were attracted from other fields of engineering, until in 1900 engineers and other geoscience professionals specializing in petroleum began to emerge from United States colleges and universities. In 1907, Kern Oil and Trading Co. of California hired five mining and geology graduates from the University of Stanford to do oil-production work. In 1914, the U.S. Bureau of Mines established its Petroleum and Natural Gas Division. University courses began to appear and the first degrees were awarded in 1916.¹

During the first thirty years of the 20th Century, petroleum engineering primarily addressed drilling, completing and producing, one well at a time. Technological improvements began to emerge which shifted the professional focus toward reservoir development and control. These advances were made possible by partnerships in research and development that included the U.S. Bureau of Mines, oil companies and universities, which led to the emergence of a robust network of research laboratories. United States petroleum engineers became the international leaders over the next four decades. Other nations sent their students to America to study and obtain degrees.² The United States literally trained the world in petroleum engineering and set the standard for education and technology.

¹ Warner, C.A.: "Sources of Men," The History of Petroleum Engineering, API, Washington, DC (1961) 1, Chap.3

² The History of Petroleum Engineering, API, Washington, DC (1961)

The international energy crises of the mid-1970s began to reshape the industry. As new nations emerged into the world economy in the post World War II boom, countries that had not previously considered a need for developing a native petroleum industry established education and research programs. From that point forward, the American petroleum industry has been profoundly shaped by the world economy, the development of reservoir resources internationally, and the boom-bust cycles of investment and activity. The industry collapses in 1986 and 1998 sent many smaller companies into bankruptcy, toppled financial institutions and caused a general constriction



and consolidation of everything from budgets, to workforce, research and educational programs. For example, BP is the result of the mergers of 10 separate companies, including British Petroleum, Amoco, Atlantic Richfield and Sinclair.

The American petroleum industry reduced its workforce fully 60 percent between 1986 and 2000, with a record 38,000 jobs lost in 1999 alone.³ Many of those laid off were World War II veterans who have since retired, taking their institutional knowledge with them. Of the remaining oil and natural gas industry workforce, half are now between the ages of 50 and 60, while only 15 percent are in their early 20's to mid-30's. The average age in the industry is 48, with some major and super major companies reporting an average age in the mid-50's. This statistic was reflected in com-

ments made by Brian Jennings, former chief financial officer of Devon Energy in an article published in 2005, "One-third of our geotechnical staff is eligible to retire in the next five years."⁴

During this bleak period, oil and natural gas companies were not the only ones losing revenues. In 1985 states collected \$7 billion in severance taxes, account-

ing for 3.3 percent of total state tax receipts. By 1993, severance tax revenue had fallen to \$4.6 billion or 1.3 percent of total tax revenues. Among the top eight producing states in 1985, energy severance taxes accounted for \$5.8 billion or 10.6 percent of state

revenues. By 1993, those states only collected \$3.7 billion or 4.3 percent of total revenues as marginal wells were shut down and E&P activities slowed.⁵ As the industry downsized, unemployment increased and state budgets were squeezed from both sides. Funding to universities and research programs dried up as corporate contributions and state funding disappeared.

Similarly, geoscience enrollment dropped 66.8 percent between 1983 and 2000.⁶ From a peak of 11,000 students enrolled at 34 universities in 1983, only 1,300 were enrolled in 17 programs by 1997.⁷ In 2004, those institutions had a combined enrollment of 1,500 students.

At the 1991 Frontiers in Education Conference, a paper entitled "Overcoming Declining Enrollments in

³ "Workforce Woes Loom," *Hart's E&P*, August, 2000

⁴ Shottenkirk, Jerry: "OKC-based Devon Attacks Aging Problem: Intern Program Accelerates," *Journal Record*, June 21, 2005

⁵ "State Energy Severance Taxes, 1985-1993," U.S. Department of Energy, Energy Information Association

⁶ "2001 Report on the Status of U.S. Academic Geoscience Departments," American Geological Institute

⁷ Mouawad, Jay: "A Global Shortage of Tools For The Oil Industry," *International Herald Tribune*, Oct. 27, 2005

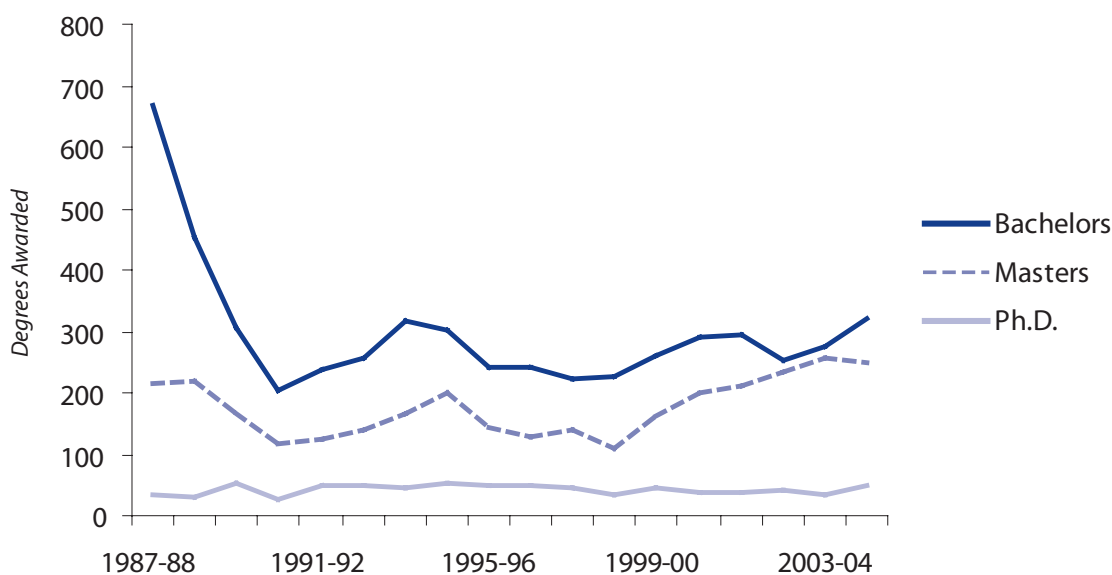
Petroleum Engineering,” noted that national enrollment in petroleum engineering dropped from 10,800 undergraduates to 1,419 in the span of five years. The study goes further to suggest that the decline is symptomatic of other engineering disciplines as well.

In a study released in March 2006, the Commission of Professionals in Science & Technology discussed some very sobering demographic trends. The report begins by pointing out the drop in U.S. births beginning in 1962 means there are 2.5 million or one-fourth fewer college-age students today than in the late 1970s. Birth rates rose after 1975, but this new generation is altogether a different group than the Baby Boomer generation. More of these children are Black, Hispanic, Native American and Asian. In 1982, minorities made up one-fourth of school-age children. Today, they account for one-third and by 2010 are estimated to account for one-half. As science and engineering have heretofore been predominantly embraced by white males, the new demographics call for a significant education paradigm shift. Unfortunately, our education system has done very little to prepare for that. At best, student interest in math and science drops drastically

after elementary school and declines throughout college. However, the drop is greater for women than for men and faster for minorities. The percentage of freshmen planning to major in engineering or any of the physical sciences has dropped steadily for 15 years.

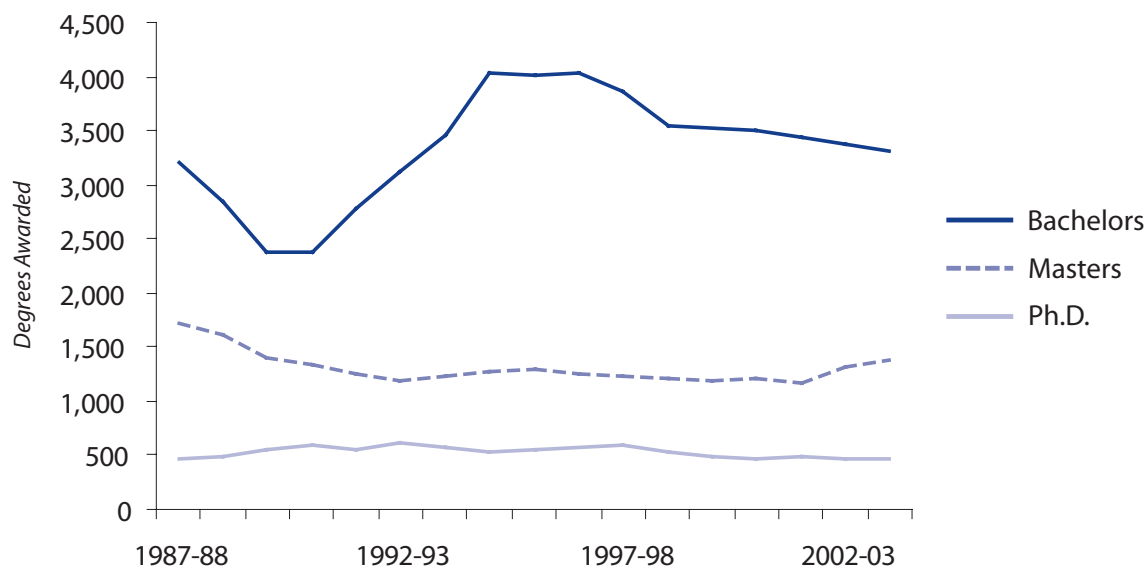
In addition, the number of freshmen enrolled in engineering is not indicative of the number who will graduate with a bachelor's degree. During the junior year, engineering degree programs access a number of students coming from other sources, including foreign students. Bachelor's degrees awarded since 1986 have dropped by 16 percent, while the number of foreign students awarded degrees has risen. In petroleum engineering specifically, B.S. degrees dropped to 307 in 1990 and less than half of those were awarded to U.S. citizens, so the real decline in degrees awarded is much steeper than it appears. To further complicate the issue, graduating seniors with a B.S. degree in petroleum engineering or the geosciences can earn significant starting salaries. These salaries not only top the offers to B.S. graduates in all other fields, but have been rising since 1990 at rates

Trends in Petroleum Engineering Degrees



Digest of Education Statistics (1990 version - 2005 version), 2004-05 data from National Center for Education Statistics COOL Database

Trends in Geology Degrees



U.S. Department of Education, National Center for Education Statistics, Higher Education

nearly double that of other fields. While this has not appeared to have attracted an increase in students enrolled in these degree programs, it has also meant fewer students remain in school to work on higher degrees, especially a doctorate. Increasingly, these spots also have gone to foreign students who have earned more than half of all Ph.D. degrees in engineering since 1980. About half of those remained to teach at universities or conduct research, but many are now leaving for their home countries, such as Korea, where emerging economies now have use for their talents.

The report concludes that a large part of the problem is our education system itself. It projects that less than half of U.S. 18-year-olds will graduate high school with sufficient background in math and science to have even the option to choose a career in engineering or the sciences. In today's technology driven world, this is a crisis.⁸

Similar issues were identified in the 2001 report on U.S. academic geoscience departments published

by the American Geological Institute. The report related the historic stability of graduate enrollment, except for a dip in 2001, where graduate enrollments declined 12 percent and degrees awarded dropped 17 percent. The report also noted that research funding support fell from 1999 to 2003, with the largest declines coming from the federal and industry sectors. In its demographic profile, it noted that while foreign-student enrollment in undergraduate programs has been declining steadily since 1992, foreign students are far more prevalent in graduate degree programs.⁹

In many respects, while it would appear that the United States is still training the world, in fact it is becoming increasingly reliant on foreign talent. Unfortunately, in a global economy where the United States has experienced the pain of outsourcing jobs via technology, insufficient attention has been given to rebuilding those education programs. Strong math and science education programs at all levels can provide jobs in this country, while maintaining technological leadership.

⁸ Betty M. Vetter: "Changing Demographics and Shrinking Engineering Enrollments," Commission on Professionals in Science & Technology, JPT, March 1992

⁹ "2001 Report on the Status of U.S. Academic Geoscience Departments," American Geological Institute



A CURRENT PERSPECTIVE

The new century quietly ushered in, if not a boom cycle, then at least an improvement in the economics of the oil and natural gas industry. Domestic energy supplies had been dwindling as the industry reduced their exploration efforts, nearly a third less in 2000 than they were in 1998.¹⁰ As geopolitical instability in the Middle East increased, world supplies were also affected. By 2002, total world consumption of marketed energy reached 412 quadrillion British thermal units (Btu).¹¹ The worldwide active drilling rig count is now nearly double that of the dark days of 1999, and that picture is predicted to sustain itself for the next 20 years.¹²

Crude oil prices have more than doubled since 1988; natural gas prices have almost tripled. The National Energy Policy Report issued by President George W. Bush in 2001 predicted an increase in U.S. oil consumption of 33 percent and natural gas consumption over 50 percent, with a concomitant increase in demand for electricity of 45 percent, and that's including aggressive practice of conservation measures. Likewise, worldwide demand continues to increase, with world oil consumption predicted to grow from levels in 2002 of 78 million barrels per day to 95 million barrels per day by 2010.¹³ World demand is being driven by emerging economies in Asia, particularly China and India, where primary energy consumption is projected to grow at an average annual rate of 3.2 percent between 2002 and 2025. Furthermore, demand is also significantly affected by the growth in information technologies. As Mark Mills, coeditor of the Digital Power Report

noted, "Every generation of microprocessors consumes more energy than the previous one and server farms that power the New Economy are huge energy users." The verity of this statement was starkly evident during the energy crisis in California in 2001. Reports noted that electricity demand in Silicon Valley had grown 6 percent annually since 1994.¹⁴

It is important to note that the world energy market has changed in one very significant respect. As we enter this new century, we will find that oil prices are now driven by world demand. In the past, OPEC, the 12 producing nations controlling the majority of the world's known petroleum reserves, controlled price through production. Supply side leverage is now yielding to world demand as supply has become relatively inelastic compared to demand. China alone is projected to account for 20 to 25 percent of global energy demand growth. Should China develop the energy consumption appetite of the United States, current world reserves would be insufficient to supply China, much less the rest of the world.

These conditions place more importance on the role of the domestic industry, which is struggling to ramp up. Just as the domestic industry was beginning to respond to the strengthening demand and already finding a shortage of drilling rigs and crews, petroleum engineers and geologists, contractors and suppliers, tankers, pipelines, storage tanks, refineries and import terminals, hurricanes Katrina and Rita sent energy supplies into

¹⁰ Mouawad, Jay: "A Global Shortage of Tools For The Oil Industry," International Herald Tribune, Oct. 27, 2005

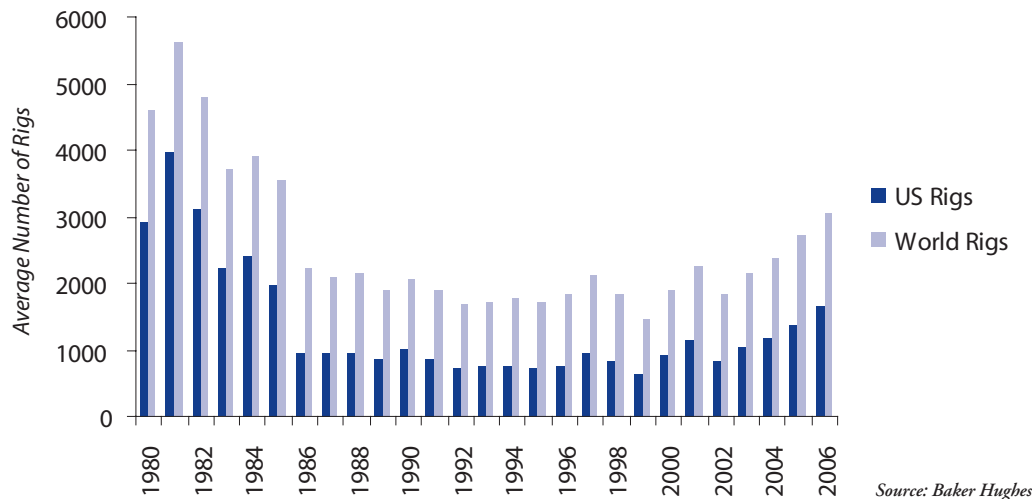
¹¹ "International Energy Outlook 2005," Energy Information Administration, August, 3, 2006

¹² Brown, David: "Boom Feels Like A Bust --For Now," Explorer, November 2003

¹³ Report of the National Energy Policy Development Group, Overview of National Energy Policy, Washington, DC, GPO, May, 2001

¹⁴ Kurlantzick, Joshua: "How Green Is the Valley?," U.S. News & World Report, April 30, 2001: 38

Average Rig Counts (United States vs. Total World)



a tailspin. In late 2005, oil prices surged past \$70 per barrel. Increased geopolitical instability from world terrorism added to the upward pressure. According to Arthur Smith, chief executive officer of John S. Herold, a research firm, “The concern now is that there will be a backlash against big oil companies who do not seem to be doing enough to bring in new supplies and push oil prices down.” And, indeed, as gasoline prices at the pump soared, the media was only too quick to target the petroleum industry, conveniently ignoring the impact of excise taxes and access restrictions. Among oil products, highway fuels (gasoline) are the most heavily taxed. Federal and state excise taxes account for 40 cents of every dollar spent at the pump.¹⁵

Nevertheless, the rapaciousness of the news reports does not bode well for an industry already suffering from a bad image. Nevertheless, the domestic petroleum industry picture is the best that it’s been in the past 15 or 20 years. Most industry experts agree that price swings and boom-and-bust cycles will continue, but expect that the lower end of the ranges will be higher than they have been.¹⁶ That bodes well for a sustainable recovery capable of attracting new talent, funding research and rebuilding education programs.

It also spells financial relief for state revenues. Severance tax collection in the first three quarters of 2005 exceeded the total collection in 2004, with top producing states reporting increases ranging from 90 percent to 135 percent over the prior year.¹⁷ For example, Kansas reported a rise of 27 percent in severance tax collections in 2005 over 2004 and an increase of 170 percent from 1999. In Oklahoma, the state budget includes a 5.1 percent growth in total funding, benefiting education, health care, public safety, roads and bridges. Most of the state’s revenue increase comes from dramatically increased gross production tax collections on oil and gas, together with a more than 10 percent increase in state income tax collection, thanks to the improved employment picture provided by energy jobs.¹⁸

Clearly, the domestic oil and natural gas industry can anticipate a brighter economic future. However, it must still resolve its greatest challenges, regenerating its workforce at all levels and re-establishing its world leadership in R&D. To do so, it must, as the 2003 Blue Ribbon Task Force Final Report suggested, establish a coordinated industry effort involving industry, government and educational institutions.

¹⁵ “Taxes on Crude Oil Production,” U.S. Department of Energy, Energy Information Administration

¹⁶ Brown, David: “Boom Feels Like A Bust –For Now,” *Explorer*, November 2003

¹⁷ “State Energy Revenues Gushing,” *StateStats*, U.S. Census Bureau, State Tax Collections 2005

¹⁸ Oklahoma Independent Petroleum Association, “Gross Production Tax Helps Coffers Overflow,” May 22, 2006



IOGCC Blue Ribbon Task Force Report

The IOGCC first warned of a shortage of personnel in its 1997 report “National Geoscience and Engineering Manpower Issues for the Petroleum Industry.” In 2001, the IOGCC published a report, “HR: the Missing Piece of the Energy Puzzle,” written by Dr. William L. Fisher and Sarah Seals, profiling the elements of the workforce crisis: market forces, jobs, workforce demographics, R&D and degree programs. Dr. Fisher called for the development of a task force to address the issue, increased efforts to win favorable public opinion toward the industry, mentoring, research and internship programs.

At the end of 2001, in my role as chairman, I assembled a Petroleum Professionals Blue Ribbon Task Force and charged it with developing proposals. The task force released its preliminary recommendations at the June 2002 meeting, following with the final report in December 2002.

Findings

The task force identified a complex network of challenges that were synergistic with the original focus on a shortage of qualified professionals and a skilled workforce. Underlying everything is the price volatility driven boom-and-bust cycles that characterize the industry. The bust cycle of the 1980s was severe enough to cause a large reduction in the excess delivery capacity that the industry had traditionally maintained. Similarly, every aspect of the industry

was downsized. Proprietary research and development by the major operating companies were exchanged for reliance on outside technology developed by service companies and universities. Unfortunately, these programs were also affected by the funding squeeze as corporate support waned. Government-funded energy R&D similarly experienced dramatic reductions. Corporate mergers dramatically reduced the workforce, many of whom left the industry permanently. The energy industry is as affected by the aging of the Boomer generation as any other industry, but the impact is exacerbated by the lack of hiring over the past 15 years, which would ordinarily have filled in the tail of the age curve. This employment climate caused a dramatic decline in the number of students seeking petroleum industry related degrees. Declines in enrollment created a loss of major educational programs.

Fortunately, the information age with its improvements in computer hardware, software and operating platforms coupled with technological advances enabled the industry to be more efficient with its workforce than at any previous time in history. As Cheryl Knight, executive director of the Petroleum Human Resources Council of Canada, notes, “The traditional sources of skilled staff are not going to be adequate ...more (Canadians) must realize how attractive the petroleum community really is as a workplace. In oil and gas, you’re judged by what you know and what you can do. This industry is remarkably open to people of any background.”

These same sentiments apply to the American petroleum industry. In its final report, the task force strongly emphasized the need for a coordinated effort involving industry, government agencies and educational institutions to establish a new understanding of today's petroleum industry and the opportunities it offers, as well as its strategic importance to our local, state and national economies.

The task force also made note of the significant changes in the domestic industry. Shifts in environmental policy and domestic access challenges encouraged the major and super-major operating companies to shift their investment emphasis to other regions of the world with large reserves and less environmental and legal regulation. Mid-size major and independent operators now represent the majority of investment in the domestic industry. These smaller companies do not have the same level of recruiting, hiring and R&D resources that the major and super-major operators have historically provided.

Recommendations

The task force concluded that the solution to its charge of regenerating the workforce requires a national effort focused on three areas:

- **State Government** - education of the public and state stakeholders
- **Federal Government** - research and national outreach
- **Industry** - on the ground focus and involvement

The task force developed templates of recommended actions for each area, calling on all stakeholders (government, agencies, academia, operating and service companies, non-governmental organizations) to join together to improve the workforce situation.

Federal Template: The federal government is the largest resource owner and chief regulator and as such must commit its infrastructure and financial resources to assure that a long-term focus is developed and maintained. Appropriate actions by the departments of the federal government (Energy, Interior, Labor, Education, and Commerce) include:

- Work with the IOGCC and other federal departments in a coordinated effort
- Provide federal funding for pilot and applied research programs and for academic research
- Inventory and advise the IOGCC and the states of grant funding available
- Each department to establish a specific staff member to liaise with the IOGCC
- Department head to alert field offices of the need to address workforce issues
- Hold federal department staff accountable for progress
- Alert the IOGCC and the states of similar projects, to avoid duplication
- Promote awareness to education associations
- Participate in a public relations campaign on the importance of the petroleum industry - use EIA/MMS materials already produced, show importance to federal budget of production on federal leases
- Create internships within federal departments for geosciences graduates and undergraduates

State Template: The states have critical roles in managing regional energy resources, providing regulatory structures and providing funding for all levels of professional and vocational education and research infrastructure. Appropriate steps a state and its agencies may take include:

- Governor appoints a specific staff or cabinet member to staff the issue
- Governor alerts state employment agency and workforce development entities, state oil and natural gas regulatory agency, and state university system and department of education
- Organize state/industry public relations campaign on importance of industry, high-tech nature using support from industry tax contributions
- Create an industry/education partnership with internship programs, continuing education credits for teachers, working with career counselors, funding research
- Educate industry on ways to improve employee retention programs
- Promote linkages to other associations (trucking, utilities, etc.) and utilization of the IOGCC Web site career center
- Outreach to U.S. Government officials and advance issue through member organizations, such as the Western Governors Association

Industry Template: Industry must work with the other stakeholders to develop and deliver a long-range plan, providing data, technology and training/ internship opportunities as well as funding. Appropriate steps industry may take include:

- Executives alert HR professionals of the need for sustained effort
- Seek support and attention of state and federal officials
- Dedicate financial resources to support state/ industry public relations, public education, and scholarship/internship programs
- Organize an industry team within the state to formulate long-term solutions
- Provide summer jobs, outreach to high school and college students, partner with specific organizations/schools
- Participate with the IOGCC electronic career resource center on the Web
- Develop scholarships and grant programs for employees to extend their education





Progress Report

Since the task force issued its final report in 2003, significant progress has been made. Most encouraging is the evidence of public-private partnerships at every level. The task force recommendations for establishing internships, scholarships and other programs designed to attract young people to petroleum science careers have especially taken root in all areas. Following is a report on the progress of each sector as it has focused on its own particular areas of leverage and applied these to positive effect. The rating scale begins at 0 for little to no effort and ends at 4 for significant effort.

Federal Actions

The task force recognized that the role of the federal sector derived most importantly from its position as the largest resource owner and chief regulator.

Fossil fuels currently provide more than 85 percent of all the energy consumed in the United States, accounting for almost two-thirds of electricity and all but a fraction of transportation fuels.



Work with the IOGCC and other federal departments in a coordinated effort



Provide federal funding for pilot and applied research programs and for academic research



Inventory and advise the IOGCC and the states of grant funding available



Each department to establish a specific staff member to liaise with the IOGCC



Department head to alert field offices of the need to address workforce issues



Hold federal department staff accountable for progress



Alert the IOGCC and the states of similar projects, to avoid duplication



Promote awareness to education associations



Participate in a public relations campaign on the importance of the petroleum industry - use EIA/MMS materials already produced, show importance to federal budget of production on federal leases



Create internships within federal departments for geosciences graduates and undergraduates

The federal government periodically struggles to address the deficit, eyeing programs with significant budgets. Pre-9/11, the defense budget and Medicare

took their hits. But global terrorism and the Baby Boomer constituency soon blocked those opportunities. During the Clinton Administration, the purchase of reserves for the Strategic Petroleum Reserve was suspended in an effort to address the federal deficit. In 1999, with the reserve dangerously low, the administration developed a new plan to fill the reserve by acquiring royalties in-kind (acquiring the crude oil itself) from federal leasehold in the Gulf of Mexico.¹⁹ Research funding recently presented itself as a budget reduction target. R&D funding had already dropped dramatically beginning in 1989, remaining flat between

2001 to current time. Of the \$8 billion budgeted in 2006 for energy R&D, only \$65 million was slated for oil and natural gas R&D. The news gets worse as the 2007 budget begins to emerge. To date, nothing is budgeted for oil and natural gas R&D within the U.S. Department of

Energy. All that remains is the \$50 million allocated from royalty receipts under the Energy Policy Act of 2005 for ultra-deep water and unconventional hydrocarbon development.²⁰

IOGCC recently published persuasive data in its 2006 Report: Marginal Wells: Fuel for Economic Growth. The report clearly demonstrates that both marginal oil and natural gas wells “are the model of conservation and economic development.” As the report notes, 17 percent of the oil and 9 percent of the natural gas produced onshore in this country come from marginal wells. Research is critical to the survival and productivity of marginal wells. Federal and state governments and universities play a crucial

role in the research and development programs which help find new methods for producing domestic energy. Independent oil and natural gas companies drill 85 percent of wells in the United States, including most marginal wells. They do not have the funds to support major research and development programs. The shrinking number of major and multinational companies has meant that today’s number of active companies supporting consortia funding for domestic university research programs has been cut in half. Without federal support for fossil energy, the productivity of marginal wells is threatened. As the IOGCC

report points out, without the production from marginal wells active in 2005, our oil imports would have increased by 6.7 percent. Moreover, if all marginal wells were abandoned, the country would realize a loss of \$11.9 billion and nearly 292,000 jobs.



Nevertheless, over the past five years, some interesting research has occurred. DOE’s Office of Fossil Energy has made headway in developing policies and technologies to assure supplies of clean, affordable energy. DOE’s Natural Gas STAR initiative is focused on reducing emissions of methane and includes more than 100 partner companies and endorsements by 11 major industry trade associations. Likewise, DOE’s Office of Natural Gas and Petroleum Technology has provided funding to a global partnership to reduce gas flaring and venting associated with the extraction of crude oil by capturing the gas and channeling it to productive uses. With 900 of the next 1,000 U. S. power plants slated to use natural gas, such unconventional recovery technologies will become

¹⁹ “Filling the Strategic Petroleum Reserve: the Royalty In Kind Initiative, Office of Fossil Energy, U.S. Department of Energy, October 4, 2006

²⁰ “Who Will Fund America’s Energy Future?” IOGCC, Dr. William F. Lawson, 2006

increasingly important economically, even as they improve the environment.²¹ Finally, although the initial results are perhaps desultory, five DOE grant initiatives administered through the Ground Water Protection Council (GWPC) focus on the development and use of databanks to reduce the time and expense of regulatory compliance. For example, more than 250 wells in North Dakota have been reworked and brought back online through horizontal drilling using readily available well information. Not only did North Dakota operators realize cost savings estimated at \$75 million, but production was maintained where a few years ago such wells would have been plugged or shut in.²²

The United States is one of the world's most mature hydrocarbon-producing regions, but environmental concerns have constrained or removed public lands rich in oil and gas from exploration and development. The DOE has selected three research projects to demonstrate ways to minimize environmental impact in a program known as LINGO (Low-Impact Natural Gas and Oil). LINGO projects have developed web-based software to enable small, independent E&P companies to generate development plans to recover tight gas shales in environmentally sensitive ecosystems while avoiding adverse impacts to air and to subsurface aquifers by using horizontal drilling techniques and eliminating venting. The third project is slated with the IOGCC for development of a "best practices" guide to viable approaches for minimizing environmental impact. IOGCC project partners include ALL Consulting, Devon Energy Corp. and the state oil and natural gas agencies of California, Nebraska, Montana and North Dakota.²³

Unfortunately, with the elimination of federal funding it is uncertain whether these fledgling programs will be able to continue, much less to evolve sufficiently to realize their full potential. Further, with

politicians still rooted in the rhetoric of the 1970s and '80s, it is clear that education and awareness of the significance of the domestic oil and natural gas industry to our domestic economy, to our standing in the global economy, and to our accustomed way of life will need to begin at the top.

Various federal departments have made progress in building a favorable partnership with industry. The Bureau of Land Management and the Minerals Management Service had both addressed royalty regulations in ways designed to offer incentives. The Internal Revenue Service revised rules applicable to depreciation and amortization. The Department of Commerce established an emergency oil and gas guaranteed loan fund. The Department of Energy and its various sub-agencies have developed and promoted robust internship programs.²⁴

State Actions

The task force appropriately noted that states also have critical roles in managing regional energy resources through regulatory and incentive structures, as well as funding for research infrastructure and professional and vocational education



Governor appoints a specific staff or cabinet member to staff the issue



Governor alerts state employment agency and workforce development entities, state oil and natural gas regulatory agency, and state university system and department of education



Organize state/industry public relations campaign on importance of industry, high-tech nature using support from industry tax contributions

²¹ "Federal/State Programs," Climate Vision, Private Sector Initiatives, August, 2005

²² "Technical Achievements of Five DOE Grant Initiatives," Ground Water Protection Council, 2005 Annual Report

²³ "DOE Initiative Targets Ultra-Low Environmental Impacts of Oil and Gas Recovery," National Energy Technology Laboratory, June 8, 2006

²⁴ "State Incentives to Maximize Oil and Gas Recovery," Investments in Energy Security, IOGCC, 2006



Create an industry/ education partnership with internship programs, continuing education credits for teachers, working with career counselors, funding research



Educate industry on ways to improve employee retention programs



Promote linkages to other associations (trucking, utilities, etc.) and utilization of the IOGCC Web site career center



Outreach to U.S. Government officials and advance issue through member organizations, such as the Western Governors Association

Progress in this sector has been stronger overall. Of the IOGCC's 37 state members, 30 reported positive activity toward improving the business investment climate for the petroleum industry in their state.²⁵

Alabama, Alaska, New Mexico, North Dakota, Oklahoma and Texas reported the largest amount of activity, combining incentives and tax reductions designed to stimulate exploration, horizontal drilling, capture of vented gas, and bringing wells back into production. Wyoming, Oklahoma, Kansas, Virginia and Alabama also reported significant activity funding demonstration, research or database development projects.

According the Hart's E&P Magazine, the oil and natural gas industry will need nearly 30,000 new petroleum engineers by 2009 to replace retiring workforce as well as meet growth demand in the industry. Students entering the workforce with petroleum engineering degrees can expect favorable

employment options. Graduates with a bachelor's degree in petroleum engineering can expect an average beginning salary of \$61,516, while their counterparts in geosciences can see starting salaries around \$45,600, according to the National Association of Colleges and Employers.

The role of educating and preparing new generations of petroleum engineers, geoscientists and skilled workers occurs at state universities and vocational training facilities.

Universities wishing to strengthen their engineering programs might wish to review the development of the Bagley College of Engineering at Mississippi State University. In 1998, the college was ranked 49th in research expenditures by the National Science Foundation. It currently ranks in the top 10 percent. The college offers a broad array of engineering degrees ranging from aerospace to mechanical. These are complemented by enhancement programs designed to equip students with career-building skills. Beyond that, the College engages in a wide variety of service and outreach programs designed to attract minority and women students at the high school level and below. The fall 2004 enrollment statistics identified an enrollment of 1,884 students in undergraduate engineering programs and 426 enrolled in graduate programs, with women representing 18 percent of total enrollment and minorities 10 percent. Once students are enrolled, student advisors work to retain students in the field, offering access to summer programs, internships and research projects.

In Oklahoma, the esteemed Mewbourne School of Petroleum Engineering at OU has seen enrollment jump from 98 in 2003 to 224 in 2006. Like Mississippi State, OU has engaged in an aggressive campaign to attract new students by securing corpo-

²⁵ "State Incentives to Maximize Oil and Gas Recovery," Investments in Energy Security, IOGCC and The Energy Council, 2006

rate grants, establishing scholarships and internship programs. Corporate partners in Texas and Oklahoma have not only provided financial support for university programs, but have benefited students with the establishment of internships and summer jobs.

Further, many states are beefing up their technical training programs specifically addressing skill development for the petroleum industry. Arkansas, Kansas, New Mexico and Oklahoma have programs recently initiated, some using state or federal workforce development pilot program funds to train lease operators, safety engineers, well service crews and other petroleum field technical skills. Older programs in California, Alaska, and Colorado are experiencing increased interest. More involvement with state workforce programs could assist this educational trend.

For states seeking to keep unemployment rates low and improve their average income profile, jobs in the engineering sciences are desirable jobs. Moreover, for producing states, these are jobs that import people to the state. In a recent news story, The Oklahoma Employment Security Commission noted that the state's jobless rate had fallen to 3.5 percent, the lowest level since 1990. Energy jobs accounted for 2.5 percent of the state's non-farm employment, with 39,900 employed in the energy sector. And, as some states have experienced, a healthy energy industry can help absorb job losses in other weakening sectors, such as manufacturing.

On the outreach measurement, some states have made significant progress in working with the energy industry to proactively develop workforce initiatives. One example lies in my home state of North Dakota.

With an unemployment rate of 3.3 percent and one of the nation's highest out-migration rates, the petroleum industry experienced poor returns on traditional recruitment efforts. In the fall of 2004, North Dakota invited the industry to participate in its workforce program, Job Service North Dakota,

operated by the state employment agency, by forwarding all their job openings. Job Service North Dakota then partnered with the North Dakota Petroleum Council to provide more profiled information about oil field positions. Job postings were aggres-



sively marketed on Web sites and through a media blitz. The agency targeted persons recently laid off in the manufacturing sector as well as people from construction, agriculture and the armed forces who were underemployed. The campaign extended into neighboring states and collaborated with the national agency, America's Job Bank. Approximately 77 percent of the positions posted were filled within the first three months of the program.

Similarly, the Oklahoma Corporation Commission established a special recruitment program to assist people impacted by the closing of the Oklahoma City General Motors plant. Partners included the

energy industry and vocational trainers. The commission hosted an event designed to bring skilled workers together with employers to fast track the hiring process. The state's Workforce Initiative also tapped energy industry HR departments to identify the skills needed in their various job sectors to assist vocational and technical training programs, to improve competency levels, and to support recruiting efforts.

Industry Actions

The task force recognized that it would be industry's role to commit funding and to initiate action both collegially within the industry and in outreach to the other sectors. It called upon industry to provide the data, technology and training opportunities on a larger scale to stimulate the development of the workforce of the future.



Executives alert HR professionals of the need for sustained effort



Seek support and attention of state and federal officials



Dedicate financial resources to support state/industry public relations, public education, and scholarship/internship programs



Organize an industry team within the state to formulate long-term solutions



Provide summer jobs, outreach to high school and college students, partner with specific organizations/schools



Participate with the IOGCC electronic career resource center on the Web



Develop scholarships and grant programs for employees to extend their education

Industry support for university programs such as scholarships, endowed chairs and the like is widespread. Industry partners are also active in research programs developed by or at universities with federal or state funding. Debi Bradley, industry and alumni liaison with OU's Mewbourne School of Petroleum and Geological Engineering, identified that 124 students are on internships with local energy companies.²⁶ The popularity of summer job or internship programs has soared. Sophomores can make \$4,000 a month, while juniors and seniors make \$5,600. From the students' perspective, internships not only help fund their college expenses, but they receive valuable training in the various aspects of their chosen field. From the companies' perspective, they are recruiting qualified people familiar with their culture and operations.

Many experts believe that the industry's poor image also affects choices students make about careers. The IOGCC called for a national energy education program. While that has not come to fruition, others have begun to step into the breach. The first state level program was created in 1994 in Oklahoma. The Oklahoma Energy Resources Board (OERB) builds the industry's image through its program of outreach by industry professionals to elementary, middle and high schools around the state. It also has restored more than 2,400 abandoned oil field sites. Former executive director Mike Terry noted in a speech to the American Petroleum Institute that public surveys revealed significant improvements in annual surveys among respondents'

²⁶ Stephen A. Martin: "As Engineering Market Booms, Students Find Slick Internships," OU Daily, June 13, 2006

perceptions of the importance of the oil and natural gas industry to the state and its overall image.

Public outreach programs developed by the Kansas Independent Oil & Gas Association have earned national recognition. They have creatively used web-based resources, events, presentations and curriculum packets. In Oklahoma, the OERB has developed public education outreach programs for Oklahoma schools. The program offers a wide variety of opportunities, including science fairs, school projects, curriculum materials and more.

In Oklahoma, the state's new History Center features the largest outdoor interpretive exhibit in the United States and the only state collection featuring derricks. According to Oklahoma Historical Society Director Bob Blackburn, the 18 acre, 215,000 square foot learning center envisioned the state's history in oil and natural gas exploration and development one of the primary elements. The collection includes photo archives, historical records and artifacts of a breadth and depth that is unparalleled. "This collection was made possible by the generosity and involvement of the oil and gas industry, from funding to collection contributions. Donors and supporters have included large companies like Devon, Chesapeake, and Andadarko as well as private individuals from Tulsa and Perry who contributed the first portable rotary rig and a Ft. Worth Spudder." OERB funded the development of a teacher's curriculum unit. Blackburn estimates that 60,000 children have visited the center's oil and gas exhibits and projects that number to rise to 100,000 within the next three years.

Additionally, companies are not only reinvesting in their assets, but also in their communities. Many, following the recommendations of the task force, have provided significant support, both in terms of

funding and in promoting volunteerism among employees, toward community needs such as adopting schools, mentoring young students and supporting conservation and beautification efforts at the community level.

Conclusion

In the three years since the task force's final report, much has been accomplished and much more has been learned about the nature of the challenges still facing the industry and the country. Most significantly, the workforce issue must be understood in the context of the macro environment. Similarly, the domestic oil and natural gas industry must also be understood in this context. And, it is up to industry and its related professional organizations to take on this task and communicate it effectively to our nation and our nation's leaders.

The imperatives for action in the next three to five years include new directions in public policy, education and resource development and management.





Next Steps

Federal Sector: This sector is not only the largest resource owner and chief regulator, but a significant beneficiary of our nation's energy resources. Afflicted by political cycles in the same way as the industry is afflicted by market cycles, it must nevertheless craft a consistent public policy cognizant of the impact of a dynamic domestic energy industry on jobs, tax revenues, balance of trade, the federal deficit and affordable, secure supplies of energy to meet our nation's needs over the long-term.

- Continue funding initiatives to build databases that make well information readily available and reduce time and expense of regulatory compliance; reduce administrative delays and duplication; and responsibly open access to existing reserves
- Establish consistent funding to support academic and applied research focused on maximizing our nation's energy resources while protecting and improving our environment
- Develop and fund national education standards to improve math and science competency among students of all ages and backgrounds, establish incentive programs to encourage state and local government, industry and private support

State Sector: This sector must continue to provide the educational, research and business infrastructure required to support a healthy energy industry.

Together with other stakeholders, it must take the lead in encouraging and developing robust education programs and collaborative initiatives in workforce development.

- Continue funding support for university research programs and collaboratively seek matching funds from outside sources, both public and private
- Continue to develop workforce initiatives designed to assist in industry recruiting and technical training
- Develop and fund state educational standards to improve math and science competency among students of all ages and backgrounds, establish scholarships and incentive programs to encourage private and local government support
- Build awareness among the public and national leadership about the significance of the energy industry to the state, its contributions to the economy and the opportunities for communities and individuals
- Partner in the development of processes to fast track the transfer of knowledge from research to commercial use to maximize resource development and utilization while benefiting and protecting the environment

Industry: As well as continuing to support and partner with entities in the other sectors, industry must step forward to give voice to its needs and potentials in securing the future of our nation, our states and

- Develop awareness building communications that tell the “story” of the oil and natural gas industry in terms of professional development, environmental stewardship, opportunities for innovation
- Partner in the development of processes to fast track the transfer of knowledge from research to commercial use to maximize resource development and utilization while benefiting and protecting the environment
- Continue the development of mentoring, internship and other workforce development programs
- Collaborate with government and academia to recruit, train and retain professional and skilled workers



Governor John Hoeven, IOGCC 2006-07 chairman



John Hoeven was born in Bismarck, N.D. He earned a bachelor's degree from Dartmouth College in 1979 and a master's degree in business administration from Northwestern University in 1981. Hoeven served as executive vice president of First Western Bank in Minot from 1986 to 1993. From

1993 to 2000, he served as president and CEO of the Bank of North Dakota, during which time the bank's assets grew from \$900 million to \$1.6 billion.

In December of 2000, Hoeven was elected governor and began working to build North Dakota's future by focusing on six pillars of growth: education, economic development, agriculture, energy, technology and quality of life. Under his leadership, North Dakota has expanded and diversified its economy, adding many new jobs and businesses. In 2003, North Dakota led the nation in personal income and wage growth, and in 2005, its rate of growth in per capita personal income was second. When much of the nation struggled through a recession and reported budget deficits, North Dakota continued to grow and diversify its economy.

In his second term as governor, Hoeven remains committed to enhancing the state's business climate, holding the line on taxes and promoting North Dakota's targeted industries, which are agriculture,

energy, technology, advanced manufacturing and tourism. He proposed new initiatives for research and additional investments in education. These include continued increases for teacher compensation and expanded funding for Centers of Excellence, an initiative that combines education and economic development to create higher-paying jobs and new business opportunities for North Dakota citizens.

Hoeven directed the development of a multi-resource energy program for the state, with incentives in each energy sector, as well as a conservation component. North Dakota is the sixth largest energy producing and exporting state in the nation and Hoeven has worked to advance the state's traditional energy resources, like lignite coal, oil and gas, while promoting renewable energy opportunities, such as wind, ethanol and biodiesel.

Hoeven previously was IOGCC chairman in 2003, when he focused on the personnel shortage in the petroleum industry and how to attract new workers. He organized a Blue Ribbon Task Force to find solutions, which led to the award-winning publication *Petroleum Pros*.

He also has previously served as chair of the Midwestern Governors Association, the National Governors Association's Health and Human Services Committee and Natural Resources Committee and the Governors' Ethanol Coalition.

Hoeven and his wife Mical (Mikey) have two children, Marcela and Jack.

About the IOGCC

The Interstate Oil and Gas Compact Commission is a multi-state government agency that promotes the conservation and efficient recovery of our nation's oil and natural gas resources while protecting health, safety and the environment.

The IOGCC consists of the governors of 37 states (30 members and seven associate states) that produce most of the oil and natural gas in the United States, as well as seven international affiliates. Chartered by Congress in 1935, the organization is the oldest and largest interstate compact in the nation.

The IOGCC assists states in balancing interests through sound regulatory practices. These interests include: maximizing domestic oil and natural gas production, minimizing the waste of irreplaceable natural resources, and protecting human and environmental health.

The IOGCC also provides an effective forum for government, industry, environmentalists and others to share information and viewpoints, allowing members to take a proactive approach to emerging technologies and environmental issues. For more information visit www.iogcc.state.ok.us or call 405-525-3556.



P.O. Box 53127, Oklahoma City, OK 73152

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www.iogcc.state.ok.us

APPENDIX

I

National Inspector Certification Exam



Created by the

Interstate Oil and Gas Compact Commission
in partnership with the U.S. Department of Energy

Applicant Information

Date: _____

Name: _____

Agency: _____

City, State, Zip: _____

Telephone: _____

Fax: _____

Email: _____

Examination Site: _____

Signature of State Director: _____

IOGCC National Inspector Certification Program

Policy Statement

This document will create, through a certification process, standards that can be used by the member states to insure that state oil and gas inspectors have the necessary skills and knowledge to conduct field inspections of oil and gas operations. The standards require that competency be demonstrated through experience and/or education and through a written examination and field check. Because of the inherent differences in geology, site characteristics, weather, operations, organizational structure and stage of development of each state, the certification program would include standards applicable to all states and standards specific to the individual states. These standards are designed to enable individual states to acknowledge levels of skill and expertise within the state inspector category and to reward higher levels of attainment. The states are encouraged to expand upon the IOGCC certification program by instituting sub certifications for advancement in grade and initiating training programs to complete the "State Inspector Program."

Purpose

The purpose of an IOGCC State Certification Program is to provide guidelines and structure to an important part of the oil and gas regulatory process. Inspections of oil and gas operations are at the heart of effective oil and gas regulation, and to date there has not been a program approved by the member states which establishes guidelines to accomplish this goal. IOGCC certification is intended to insure that state inspectors have the skills and knowledge necessary to conduct inspections of oil and gas operations in a safe and competent manner. The program will define a consistent nationwide level of expertise among oil and gas state inspectors. The IOGCC program lists certification criteria applicable to all states, and optional criteria which can either be incorporated as mandatory criteria for an individual state program, or as sub certifications for advancement within the state inspection category. The IOGCC recognizes that many of the optional criteria are not applicable to all states and therefore, the designation is "optional."

To further increase the effectiveness of state inspectors and thus, state programs, the IOGCC could provide training in many of the optional categories.

Authority

The authority to grant and withdraw certification and to grant re-certification is vested in the IOGCC. The program will be under the jurisdiction of the IOGCC Council of State Regulatory Officials who will oversee testing and certification criteria. The chairman of the Council of State Regulatory Officials shall appoint a three person Certification Board with staggered terms who will approve state qualification criteria and competency in state rules. Evidence of certification will be a document signed by an officer of the IOGCC, embossed with the "IOGCC seal." Certification by the IOGCC is not intended to preempt nor usurp the authority of states to control and manage their respective oil and gas regulatory programs and personnel.

Certification Exam Topics

DRILLING PROCEDURES

HORIZONTAL/DIRECTIONAL DRILLING

CEMENTING PROCEDURES

SITE AND PIT SELECTION

WELL COMPLETION PROCEDURES

UNDERGROUND INJECTION

PRODUCTION

H₂S

POLLUTION PREVENTION

NORM

COMMUNICATION AND MEDIATION

KNOWLEDGE OF WELL PLUGGING PROCEDURES
AND REQUIRED PERFORMANCE OBJECTIVES

OILFIELD TERMINOLOGY

TOPOGRAPHIC MAP

SEISMIC ACTIVITY

IOGCC National Inspector Certification Exam DIRECTIONS

To: Applicants for State Oil and Gas Field Inspector Certification Examination

All questions are multiple choice, fill-in or true-false.

Several suggested answers or completions follow each question or incomplete statement. Select the one that BEST answers the question or completes the statement. Circle the entire answer.

***NOTE – In some categories, more than one answer will apply.**

The examination includes the following illustrations and diagrams:

- Drilling Rig and Pumping Unit
- Drill Stem Test
- Lease Production Site
- Topographic Map

Length of Examination:

Two (2) hours

Minimum Passing Grade:

70%

Section One: Drilling Procedures

*NOTE – In some questions, more than one answer will apply. Circle the entire answer(s).

- 1) A surface blowout is caused by:
 - a) An under-balanced mud column.
 - b) An over-balanced mud column.
 - c) Drilling into a low-pressure reservoir.

- 2) What causes lost circulation?
 - a) An under-balanced mud column.
 - b) An over-balanced mud column.
 - c) Drilling into a high-pressure reservoir.

- 3) What are the purposes of drilling mud?
 - a) To improve reservoir porosity and permeability.
 - b) Remove cuttings from the hole.
 - c) Suspend cuttings when circulation stops.
 - d) Prevent water loss.
 - e) Cool and lube the bit.
 - f) Line the hole with filter cake.
 - g) Prevent contamination of the reservoir.
 - h) Control subsurface pressure.
 - i) All of the above.

- 4) During a drill stem test if the fluid level in the hole falls, it is an indication of:
 - a) Packer failure.
 - b) Fluid entering the test tool.
 - c) Loss of drilling fluid.

5) What are the factors that control the rate of penetration?

- a) Surface temperature
- b) Bit type
- c) Rock properties
- d) Drilling mud properties
- e) Reserve pit capacity
- f) WOB (weight on bit)
- g) Mud pump capacity
- h) Personnel efficiency
- i) Rig efficiency
- j) RPM

6) What is the purpose of a drill stem test?

- a) To find data about the formation.
- b) To determine shut-in time.
- c) Increase porosity and permeability of the formation.
- d) To find the amount and type of fluid the formation will give up.
- e) To monitor changes in formation pressure over time.

7) Gas and water cushions are used in drill stem testing to:

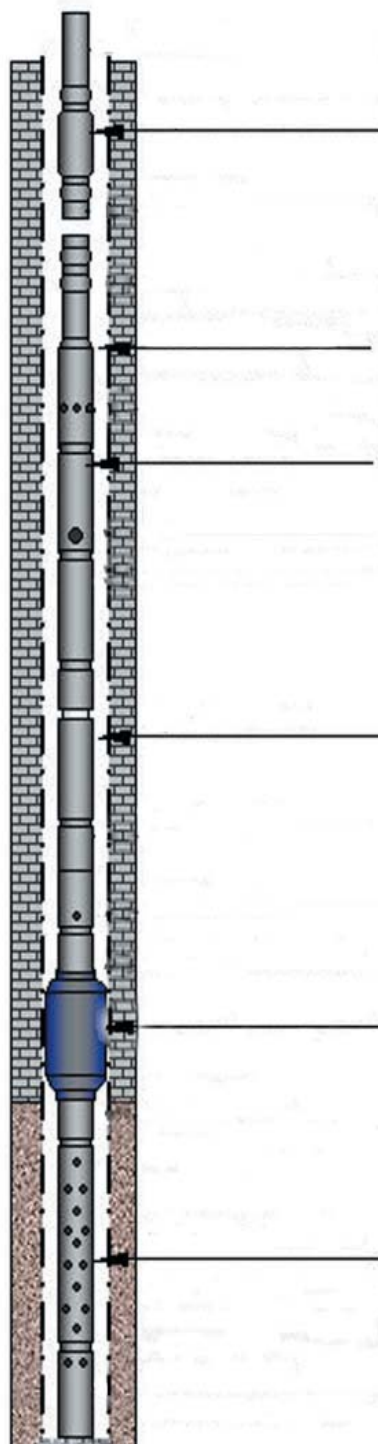
- a) Prevent drill pipe from collapsing.
- b) Reduce shock when tool is opened.
- c) Control fluid influx.
- d) Reduce testing time.

8) When is the safest time to open the test tool?

- a) Night time
- b) Day time
- c) Any time

9) Identify any four components on the drill stem test diagram shown below:

- _____ Packer
- _____ Surface Casing
- _____ Core barrel
- _____ Production Casing
- _____ Submersible pump
- _____ Pressure Recorder
- _____ Drill Pipe
- _____ Perforated Anchor
- _____ Test Valve



10) What is the purpose of a whip stock?

- a) Used to assist in setting a cement retainer.
- b) To change the direction of the hole.
- c) To assist in setting packers for a drill stem test.

11) What is a pipe tally and strap?

- a) A measurement of the drilling assembly.
- b) A determination of the weight on the bit.
- c) A measure of the diameter of the drill pipe being used.
- d) To determine volume of fluid drill pipe may contain.

12) What is the single most significant indication that a blowout is underway?

- a) Cussing on the part of the driller.
- b) Increased weight on the bit.
- c) Increase in the volume of mud in the tanks.

13) The person in charge of the drilling rig is:

- a) The Pumper
- b) The derrick man
- c) The tool pusher
- d) The field foreman

14) What are the types of rams on a blowout preventer?

- a) Motor rams
- b) Pipe rams
- c) Shear rams
- d) Dodge rams
- e) Blind rams
- f) Battering rams

15) What is the purpose of each of the above rams?

- a) Confine fluids to their initial zones.
- b) Maintain reservoir pressure.
- c) Close the hole.
- d) Shear off the tubulars in the hole.
- e) Close the hole around pipe.
- f) Confine fluids to their respective zones.

16) What determines the maximum pressure for a blowout preventer (BOP) system?

- a) The capability of the rig pump.
- b) The bottom hole pressure of the highest-pressure formation to be penetrated.
- c) The pressure rating of the weakest component.

17) What is the purpose of an accumulator?

- a) Stores bottom hole pressure data.
- b) Provides pressure for the operation of the blowout preventer (BOP) equipment.
- c) Accumulates fluids coming up the hole.

18) What is the advantage of an annular preventer (hydril)?

- a) Operates in all types of weather.
- b) Can close the hole around tools, the kelly, or pipe.
- c) Only needs maintenance annually.
- d) Operates on low pressure.

19) Drilling mud accomplished many purposes in drilling a well. What are the purposes?

- a) To lubricate the bit.
- b) To leach carbonates while penetrating and thus increase porosity.
- c) To carry rock cuttings to the surface for analysis.
- d) To prevent the hole from caving in.
- e) To balance the pH of the formations being penetrated.

Components of the Rotary Rig

20) This page contains a list of components found on a rotary drilling rig and a pumping unit. Identify all 30 components of the rotary rig and identify all 18 components of the pumping unit using the illustration found on the following page.

Please place corresponding number from diagram in front of the item that it identifies.

- | | |
|--------------------|------------------------------|
| _____ Pitman | _____ Prime mover |
| _____ Polished Rod | _____ Counter Weight |
| _____ Casing Head | _____ Casing Cement (Slurry) |
| _____ Tubing | _____ Rod Pump |
| _____ Separator | _____ Stock Tanks |
| _____ Sampson Post | _____ Gear Reducer |
| _____ Walking Beam | _____ Horse Head |
| _____ Sucker Rod | _____ Bridle |
| _____ Stuffing Box | _____ Thief Hatch |

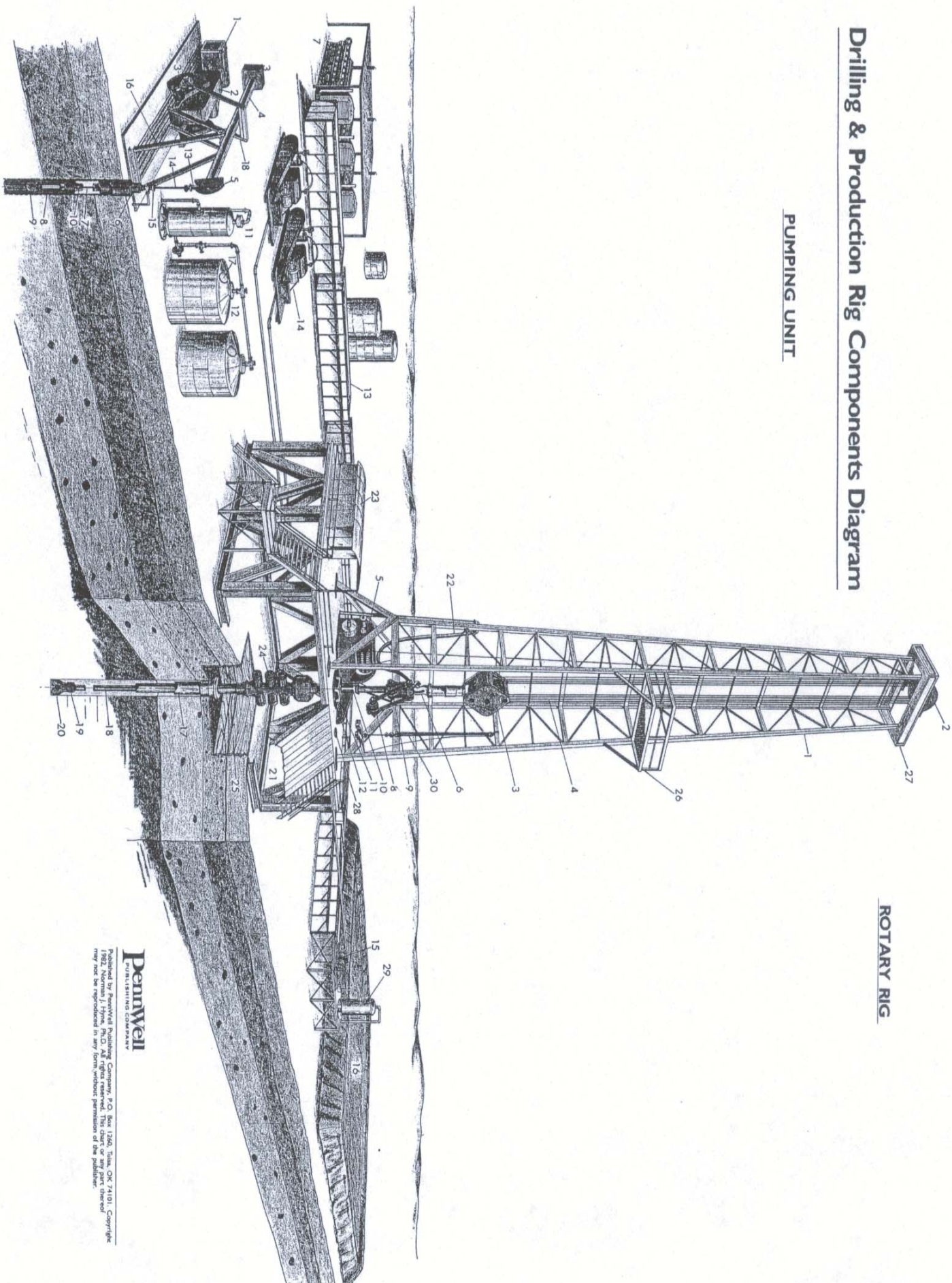
Rotary Rig

- | | |
|-------------------------------|-------------------------------------|
| _____ Dog house | _____ Tongs |
| _____ Mud Pits | _____ Drill Collars |
| _____ Kelly | _____ Kelly Bushing |
| _____ Swivel | _____ Engines |
| _____ Drill Bit | _____ Crown Block |
| _____ Monkeyboard | _____ Draw Works |
| _____ Traveling Block | _____ Hook |
| _____ Mouse hole | _____ Water Table |
| _____ Blowout Preventer Stack | _____ Rotary Table – Master Bushing |
| _____ Mast Derrick | _____ Drilling Line |
| _____ Reserve Pits | _____ Mud Pumps |
| _____ Shale Shaker | _____ Elevators |
| _____ Casing | _____ Cellar |
| _____ Mud Gas Separator | _____ Drill Pipe |
| _____ Pipe Ramp | _____ Rotary Hose |

Drilling & Production Rig Components Diagram

PUMPING UNIT

ROTARY RIG



Section Two: Horizontal/Directional Drilling

- 1) In relation to horizontal drilling, what does MWD stand for?
 - a) Movement without deviation.
 - b) Movement with drag.
 - c) Measurement while drilling.

- 2) Why is a Gyro the only directional tool that will achieve correct reading inside casing?
 - a) Because it is a non magnetic tool, therefore the steel of the casing has no effect on it.
 - b) Because while it is moving, the Gyro is magnetic.
 - c) Because both the casing and the Gyro have a negative charge.

- 3) What is Declination?
 - a) The angle between the plain of the surface and the well bore.
 - b) The angle between true north and magnetic north.
 - c) The angle between the rig floor and the well bore.

- (4) What are two ways the raw data (inclination, azimuth) can be transmitted to the surface from the tools at depth?
 - a) Transmitted through the wire line.
 - b) Transmitted through the drilling string.
 - c) Transmitted through the drilling mud.
 - d) Transmitted through electronic impulses.

- 5) Position the bit at the desired angle and engage the mud motor to rotate the bit.
 - a) This is a description of the mechanics of steering a horizontal well bore.
 - b) This is a description of what is commonly referred to as "sliding".
 - c) This is a description of cutting a window for sidetracking.

6) What is a sidetrack?

- a) A new leg or lateral drilled from the original horizontal well bore.
- b) A new well bore drilling parallel to the old well bore.
- c) Moving the drilling rig and starting an entirely new well bore.
- d) A tracking measurement taken along the side of the hole.

7) Time drilling is the process of starting a sidetrack by rotating the bit in a desired orientation with no weight on the bit.

- a) True
- b) False

8) Does Magnetic North change over time?

- a) Yes
- b) No

9) What are Monel collars?

- a) Non magnetic collars used in the directional drilling process to eliminate magnetic interference.
- b) Weighted drill collars.
- c) Collars with a wire line attached.

10) When is it necessary to use wire line in a directional drilling operation?

- a) When there is a problem with excessive deviation.
- b) When there are no drilling fluid returns to the surface.
- c) When the viscosity of the drilling fluid is too high.

Section Three: Cementing Procedures

*NOTE – In some questions, more than one answer will apply. Circle the entire answer(s).

1) Identify the functions of any cement job.

- a) Support the casing.
- b) Retard casing corrosion.
- c) Protect fresh water zones.
- d) Isolate oil, gas, and water bearing zones.
- e) Stabilize the hole.

2) To set a 100 foot plug in a 7 7/8 inch well bore it takes approximately twice as much cement as it does for a 4 5/8 inch well bore.

- a) True
- b) False

3) What is WOC?

- a) Waiting on contractor.
- b) Waiting on cement.
- c) Without cement.

4) Which of the following do you need to know to properly set a cement plug?

- a) Length of drill pipe.
- b) Diameter of drill pipe.
- c) Size of the hole.
- d) All of the above.

- 5) What is a multi-stage cement job?
- a) An operation where cement is pumped through the casing at a DV tool.
 - b) An operation where cement comes to the surface.
 - c) An operation conducted on a separately constructed stage.
 - d) Cementing operation conducted on two separate days.
- 6) Rule of thumb says that it takes 35 sacks of cement per 100 feet of well bore in a 7 7/8 inch hole.
- a) True
 - b) False
- 7) What is the purpose of a Cement Bond Log?
- a) To insure the adequacy of the cement job.
 - b) To check the quality of the casing.
 - c) To show the water / oil contact line.
- 8) Why should surface casing be cemented to the surface?
- a) To adequately facilitate mud circulation.
 - b) To insure adequate cement coverage over all fresh water aquifers and prevent failure of the surface pipe during subsequent drilling.
 - c) To eliminate the possibility of small hand tools being dropped down the annulus.
- 9) Why is it necessary to tag the plug?
- a) To relocate the plug to a more desirable location before it sets.
 - b) To make sure the plug is properly placed and the cement has set properly.
 - c) To test the strength of the casing.

10) What is the main purpose for using a 50/50 poz mix in a well?

- a) To reduce cement cost.
- b) To retard the setting time.
- c) To provide a stronger bond.
- d) To avoid fracturing the formation.
- e) To reduce rig time for the cementing operation.

11) What should a field inspector observe when witnessing a squeeze job?

- a) Pressure at start and end of squeeze.
- b) Continuous or staged pumping.
- c) Amount and type of cement pumped.
- d) Rate of pumping (barrels per minute).
- e) Viscosity of the oil.
- f) The competency of the contractor.

12) The most successful cement job is when cement is circulated through the tubing and up the hole in contrast to cement being squeezed down the annulus with the tubing shut in.

- a) True
- b) False

13) Why is it important to circulate cement to the surface when setting surface casing?

- a) To isolate water bearing zones from the rest of the well bore.
- b) To stabilize the surface casing.
- c) To prevent casing from rusting.
- d) To provide an anchor for production tubing.

Section Four: Site and Pit Selection

*NOTE – In some questions, more than one answer will apply. Circle the entire answer(s).

- 1) What is the single most important factor in selecting a drilling site?
 - a) The geological probabilities of finding commercial oil and gas.
 - b) Complying with optimum topographic conditions.
 - c) Minimizing the cut and fill required to develop the site.
 - d) The distances from the nearest road.

- 2) What factors affect the requirement to line a pit?
 - a) Presence of migratory birds.
 - b) Type of drilling fluid used.
 - c) Presence of fresh water aquifer near the surface.
 - d) Type of soil where pit will be dug.
 - e) Presence of a wildlife habitat in the area.
 - f) All of the above.

- 3) Circle all factors that influence where the well is to be located.
 - a) State spacing rules.
 - b) Proximity to buildings.
 - c) Proximity to water wells.
 - d) Location in relation to surface drainage.
 - e) Geological and geographical criteria.
 - f) Presence of wildlife.
 - g) Proximity to major highways.
 - h) Existence of a shallow underground aquifer.
 - i) All of the above.
 - j) None of the above.

- 4) On a producing well site, what erosion issues should an inspector be looking for?
 - a) Erosion of berm around a tank battery.
 - b) Erosion of soil around the wellhead.
 - c) Top soil erosion in the surrounding field.

- 5) Unlined pits should be prohibited where they:
- a) Are larger than 20 feet by 20 feet.
 - b) Pose a potential threat to ground water contamination because of the presence of shallow ground water.
 - c) Are located in soil that is impermeable.
 - d) Receive more than 10 barrels per day of fluid.
 - e) Are located in close proximity to drainage.
- 6) What parties could be involved in the selection of the drill site?
- a) Landowner
 - b) The governing regulatory agency.
 - c) EPA
 - d) The operator.
- 7) Is protection of wildlife habitat & protection of surface water to be considered when selecting a drill site?
- a) Yes
 - b) No
 - c) Not a consideration of the State.
- 8) Is erosion a factor to be considered in site selection?
- a) Yes
 - b) No
- 9) What factors affect the size and location of a reserve pit?
- a) Proximity to waterway for ease of draining.
 - b) Use as wildlife area after drilling.
 - c) Availability of fill to minimize location size.
 - d) Availability of porous material to facilitate draining.
 - e) All of the above.
 - f) None of the above.
- 10) Is erosion a factor to be considered in restoration of a pit?
- a) Yes
 - b) No

Section Five: Well Completion Procedures

*NOTE – In some questions, more than one answer will apply. Circle the entire answer(s).

1) Match the principal type of oil well completion with the proper definition:

- a) _____ Open hole completion
- b) _____ Perforated casing completion
- c) _____ Recompletion
- d) _____ Liner completion
- e) _____ Dual completion

- (1) Producing oil from two separate zones.
- (2) Producing oil through holes shot through cemented production casing.
- (3) Squeezing off existing perforations with cement and reperfing the well.
- (4) Producing oil below cemented casing.
- (5) Producing oil from a separate piece of pipe which is anchored to existing casing.

2) What is the purpose of a Frac job?

- a) To increase the permeability of the producing formation.
- b) To increase the porosity of the producing formation.
- c) To increase the pressure drop across the producing reservoir.

3) Acidizing does the following:

- a) Increases the amount of fluid in the reservoir.
- b) Increases the porosity and permeability in a silica sand reservoir.
- c) Cleans the portion of the reservoir contaminated by drilling fluid.
- d) Increases the porosity and permeability in a carbonate reservoir.
- e) Cleans up the cement around the perforations.
- f) Neutralizes the pH of produced water within the formation.

4) Has a frac job ever been proven to have contaminated a fresh water zone?

- a) Yes
- b) No

- 5) What is the primary purpose of a Gas-Oil Ratio Test?
- a) To measure the amount of oil the well is capable of producing.
 - b) To define whether the well is an oil well or gas well.
 - c) To aid the operator in defining the producing characteristics of the well.
- 6) What is an open hole completion?
- a) A completion where the hole is open at the surface.
 - b) A completion where there is no packer in the hole and thus open to free fluid flow.
 - c) A completion where pipe is cemented above the producing formation and there is no perforated pipe opposite the pay zone.
 - d) A hole where there is no tubing in the hole.
- 7) If you were to design a frac job, what factors do you take into consideration?
- a) The cement job on the casing.
 - b) The proximity to a freshwater aquifer.
 - c) The bottom hole pressure of the formation to be fraced.
 - d) Adequate packer assembly.
 - e) Sand size because it is the only appropriate propping agent.
 - f) The type of permeability in the zone to be fraced.
- 8) A work over rig can be utilized to perform many operations. Circle all that apply from the list below.
- | | |
|----------------------------|-----------------------|
| a) Drill below 10,000 feet | h) Pull or run tubing |
| b) Cement well | i) Run casing |
| c) Recomplete the well | j) Repair the well |
| d) Perform frac job | k) Replace rods |
| e) Conduct seismic surveys | l) Perform acid job |
| f) Swab well | m) Plug well |
| g) Set pump | |
- 9) A single frac can stimulate an entire multiple well field.
- a) True
 - b) False

Section Six: Underground Injection

- 1) What is the purpose of a mechanical integrity test or MIT?
 - a) Insure that tubing and casing does not leak fluid.
 - b) Insure that surface equipment operates without leaks.
 - c) Insure that artificial lift operates without leaks.
 - d) Insure that flow lines operate without leaking.

- 2) What is the reason for water being injected into a formation?
 - a) To clean the perforations.
 - b) Increase reservoir pressure.
 - c) To build up hydrostatic pressure around the well bore.
 - d) Sweep the formation of oil.
 - e) Dispose of water unfit to discharge on the surface.

- 3) What is the danger of injection pressure exceeding the initial bottom hole pressure of the injection zone?
 - a) Such a procedure would strain the mechanical integrity of the injection equipment.
 - b) Such a procedure would allow for contamination of reservoir fluid.
 - c) Such a procedure could fracture the confining formation allowing flow of fluids out of zone.

- 4) Class II underground injection wells are used exclusively for the disposal of produced water.
 - a) True
 - b) False

- 5) Of the five classes of wells under the U.I.C. Regulations, which of these includes oil and gas activity?
 - a) Class I
 - b) Class II
 - c) Class III
 - d) Class IV
 - e) Class V

- 6) An injection zone could be exempt from protection as fresh and potable water. What are the situations that could provide an exemption?
- a) It is mineral, hydrocarbon, or geothermal energy producing.
 - b) It is situated at a depth or location that makes recovery of fresh and potable water economically or technologically impractical.
 - c) It is so contaminated that it would be economically or technologically impractical to render the water fit for use as fresh and potable water.
 - d) It is located over a mining area subject to subsidence or catastrophic collapse.
 - e) It has a total dissolved solids (TDS) of more than 5,000 and less than 10,000 milligrams per liter (mg/l) and is not reasonably expected to be used as fresh or potable water.
 - f) The salt concentration is greater than 4,000 ppm.
 - g) There is no known beneficial use for the fresh water.
- 7) What percent of leak off does EPA allow for an injection well during an MIT test?
- a) 50% in one hour
 - b) 25% in one hour
 - c) 10% in 30 minutes
 - d) 5% in 15 minutes
- 8) Why does the EPA require an area of investigation for an injection well?
- a) Because it is mandated by Congress.
 - b) Because it is necessary to know the number of wells within the area of investigation.
 - c) Because some well bores may provide an open pathway for injection fluids to enter and contaminate other formations.
 - d) To evaluate the integrity of the casing in surrounding wells.
- 9) What should be done to prevent the migration of injected fluids into protectable fresh water zones?
- a) Inject below known fresh water zones.
 - b) Ensure that the proposed injection well is constructed with cement outside the casing.
 - c) Limit the amount of fluid that can be injected on a daily basis.
 - d) Ensure that the injected fluid does not exceed salt concentrations of 100,000 ppm.
 - e) Ensure that the wells in the area are properly plugged.
- 10) Injected fluids can be confined to defined property lines by:
- a) Limiting injection pressure.
 - b) Limiting injection volumes.
 - c) Careful monitoring of the water quality.
 - d) None of the above.

Section Seven: Production

1) What are the types of artificial lift that bring oil from the reservoir to the surface?

- a) Submersible pumping
- b) Gas lift
- c) Beam pumping rod
- d) Hydraulic pumping
- e) Vacuum pump
- f) Hand pump

2) The methods used to separate oil and water are:

- a) Heater treater
- b) Free water knock out
- c) Separator
- d) Reverse osmosis equipment

3) If a tank of oil has 5% water, the purchaser pays 95% of the volume.

- a) True
- b) False

4) Which of the following methods are used for measuring oil?

- a) Siphon method
- b) Tank gauging
- c) Bucket and stop watch
- d) LACT meter

5) What is the only effective method of measuring gas volume?

- a) Pitot tube
- b) Meter with appropriate orifice plate
- c) Gas valve

6) The price per barrel of the sale of oil is determined by what factors?

- a) Gravity
- b) Sulfur content
- c) Percentage of water
- d) Amount of gas
- e) Depth of well

7) What factors affect the volume of oil in tanks?

- a) Gravity
- b) GOR
- c) Temperature
- d) Color

8) The diagram depicts a lease production site. Properly identify all 14 of the numbered components

Place Figure 3 here

Section Eight: H_2S

- 1) Lethal concentrations of H_2S smell like:
 - a) Rotten eggs.
 - b) Has no odor.
 - c) Lemons.

- 2) The most important piece of safety equipment an inspector should have when he/she finds themselves in an area containing H_2S is:
 - a) An H_2S monitor.
 - b) A pair of fast running shoes.
 - c) An H_2S five-minute escape pack, SCBA, or Scott air pack.

- 3) H_2S concentrations are heavier than air and tend to settle in low-lying areas.
 - a) True
 - b) False

- 4) The appropriate procedure to determine if H_2S is present in a closed tank is to open the hatch and smell the contents.
 - a) True
 - b) False

- 5) In the event you find yourself in an H_2S environment and discover a co-worker down and unconscious, what is the appropriate procedure?
 - a) Hold your breath and immediately drag him to safety.
 - b) Don SCBA equipment.
 - c) Call for emergency backup.
 - d) Hold handkerchief over your mouth before attempting rescue.
 - e) All of the above.

- 16) Produced water tanks can have higher concentrations of H₂S than oil storage tanks.
- a) True
 - b) False
- 7) In a sour crude facility, H₂S can be found in a water tank, oil tank, or treater.
- a) True
 - b) False
- 8) A healthy person is exposed to H₂S, momentarily losing consciousness. He is able to regain consciousness, stating that he is okay and appearing to be fully recovered. What procedure should you take?
- a) Allow him to continue working.
 - b) Seek medical attention immediately.
 - c) Contact his supervisor.
 - d) Give him Pepto-Bismol.
- 9) When entering a lease with suspected H₂S presence and a yellow flag is flying, what should you do?
- a) Check your escape pack.
 - b) Turn around.
 - c) Approach with caution.
 - d) All of the above under certain circumstances.
- 10) H₂S has a distinct smell of rotten eggs in low concentrations.
- a) True
 - b) False

Section Nine: Pollution Prevention

1) Identify the operating procedures and equipment used to prevent pollution.

- | | |
|-------------------|----------------------|
| a) Berms | g) Pit liners |
| b) Flare pits | h) Mud tanks |
| c) Disposal wells | i) Netting pits |
| d) Fire walls | j) Fencing the lease |
| e) Well location | |
| f) Flare igniters | |

2) List in order from 1 to 4 the most desirable method of waste management, to the least desirable:

_____	Treatment
_____	Disposal
_____	Recycling
_____	Source Reduction

3) After a spill occurs, the first thing a field inspector should do is call the EPA.

- a) True
- b) False

4) The most effective treatment for an oil spill is to cover it with dirt.

- a) True
- b) False

5) Bioremediation is an effective form of oil spill treatment.

- a) True
- b) False

6) Of the following, which is most dangerous to human health?

- a) Salt water
- b) H₂S
- c) CO₂
- d) SO₂
- e) Nitrogen

7) A berm is used for:

- a) Scenic beauty.
- b) Fluid containment.
- c) To stop vehicles.
- d) Topographical formation.

8) What are the methods to reclaim or dispose of pit site contents?

- a) Solidification of the pit.
- b) Removal of all pit fluids from the site.
- c) Pit content spread on location.
- d) Pit content spread on roads.
- e) Incineration.
- f) Injection into a dry hole.
- g) Land farming off location.
- h) Neutralized pit acidity with chemicals.

9) The most environmentally preferable method for storing fluids is:

- a) Lined pits.
- b) Tanks.
- c) Unlined pits.

10) What is the single most important factor to consider during site restoration or pit closure?

- a) Handling of drilling fluids within the pit.
- b) Restoration of surface to reasonable facsimile of condition prior to drilling.
- c) Type of soil.
- d) Chemical composition of pit fluid.

II) Although fresh water is a relative term, underground waters are generally considered protectable if they contain:

- a) 10 parts per million dissolved solids.
- b) 10,000 parts per million dissolved solids.
- c) 100,000 parts per million dissolved solids.

12) The level of clean up required at a site is dependent upon:

- a) Depth to ground water.
- b) The horizontal distance to all water sources.
- c) The amount of oil that was produced on site.
- d) The length of time the well produced.

13) Oil spills on land should first be reported to:

- a) The landowner.
- b) The sheriff's department.
- c) The state oil and gas regulatory agency.
- d) The EPA.

14) The Vadose zone is defined as:

- a) The saturated earth material below the land surface.
- b) The unsaturated earth material below the land surface.
- c) The zone immediately above the injection zone.
- d) The zone of contaminated fresh water.

15) Prior to site abandonment, soils within and beneath unlined surface impoundments should be evaluated to determine the type and extent of contamination, if any.

- a) True
- b) False

Section Ten: NORM

- 1) In oilfield terminology, what is N.O.R.M.?
 - a) Normal Operating Radioactive Material
 - b) Non Ordinary Radioactive Material
 - c) Naturally Occurring Radioactive Material

- 2) NORM is a hazardous waste regulated under Sub-Title C of the Resource Conservation and Recovery Act (RCRA).
 - a) True
 - b) False

- 3) What level of NORM above background is generally considered to be the regulatory threshold?
 - a) Above 30 picocuries per gram of radium 226
 - b) Above 300 picocuries per gram of radium 226
 - c) Above 3 picocuries per gram of radium 226

- 4) NORM generally occurs highly concentrated in:
 - a) Scales and sludges.
 - b) Fresh water aquifers.
 - c) Dehydrates.

- 5) Subject to specific requirements, acceptable disposal of NORM can be performed by:
 - a) Injection into underground zones below fresh water.
 - b) Down hole disposal in wells to be plugged and abandoned.
 - c) Disposal in commercial or centralized surface waste management facilities.

Section Eleven: Communication and Mediation

- 1) The most effective method for resolving conflicts between producers and landowners is:
 - a) Confrontation
 - b) Litigation
 - c) Mediation

- 2) The most important mediation skill for a field inspector to have is:
 - a) The ability to persuade.
 - b) The ability to argue.
 - c) The ability to listen.

- 3) Which of the following are important communication skills?
 - a) Verbal
 - b) Written
 - c) Body language
 - d) All of the above

- 4) The most effective form of communication in the oil patch is:
 - a) Telephone contact
 - b) E-mail
 - c) Personal contact
 - d) U.S. Mail

- 5) Prior to arriving on location for an inspection, a field inspector should first:
 - a) Notify EPA
 - b) Notify the Operator
 - c) Call the state police and request an armed escort.
 - d) Show up without notifying anyone.

Section Twelve: Well plugging procedures and required performance objectives

- 1) Plugs are primarily required to:
 - a) Stabilize the hole.
 - b) Isolate fluid bearing formations.
 - c) Prevent the hole from collapsing.
 - d) Prevent a downhole blowout.

- 2) Of the following, which conditions affect the plugging procedure for a well to be abandoned?
 - a) Casing
 - b) Fluid in the hole
 - c) Producer or dry hole
 - d) Formation tops
 - e) Depth of well
 - f) Length of time well produced
 - g) Bottom hole temperature
 - h) Cost of plugging
 - i) Junk in well

- 3) Cement plugs should be set:
 - a) Across perforations or within 100 feet above top of perforations or casing shoe.
 - b) Above and below casing cut points (stubs).
 - c) To isolate other oil, gas or water zones exposed in the well bore.
 - d) Across casing shoes.
 - e) At the surface.
 - f) At periodic intervals to stabilize the hole.

- 4) The minimum size for a down hole cement plug should be:
 - a) Not less than 100 feet or 35 sacks, whichever is greater.
 - b) Not less than 10 feet or 2 sacks, whichever is greater.
 - c) Not less than 100 sacks.

- 5) The identification of wells that may need to be plugged is evidenced by:
 - a) Surface equipment missing.
 - b) Lack of power connection.
 - c) Broken flow lines.
 - d) None of the above.
 - e) All of the above.

Section Thirteen: Oilfield Terminology

The following pages contain definitions. Match all 32 terms with the correct definitions.

Letters A - J

_____ Core barrel
_____ Deviation
_____ Deviation survey
_____ Impermeable
_____ Drill-stem test
_____ Drum
_____ Elevators
_____ Fingerboard
_____ Doghouse
_____ Kelly bushing

Letters K - U

_____ LACT Unit
_____ Log
_____ Overshot
_____ Rathole
_____ Porosity
_____ Proppant
_____ Round trip
_____ Permeability
_____ Nipple up
_____ Spud
_____ Mousehole

Letters V – FF

_____ Casing shoe
_____ Blowout
_____ Christmas tree
_____ Cellar
_____ Cable tool drilling
_____ Conductor pipe
_____ Blowout Preventer
_____ Cement channeling
_____ Circulation
_____ Casing centralizer
_____ String

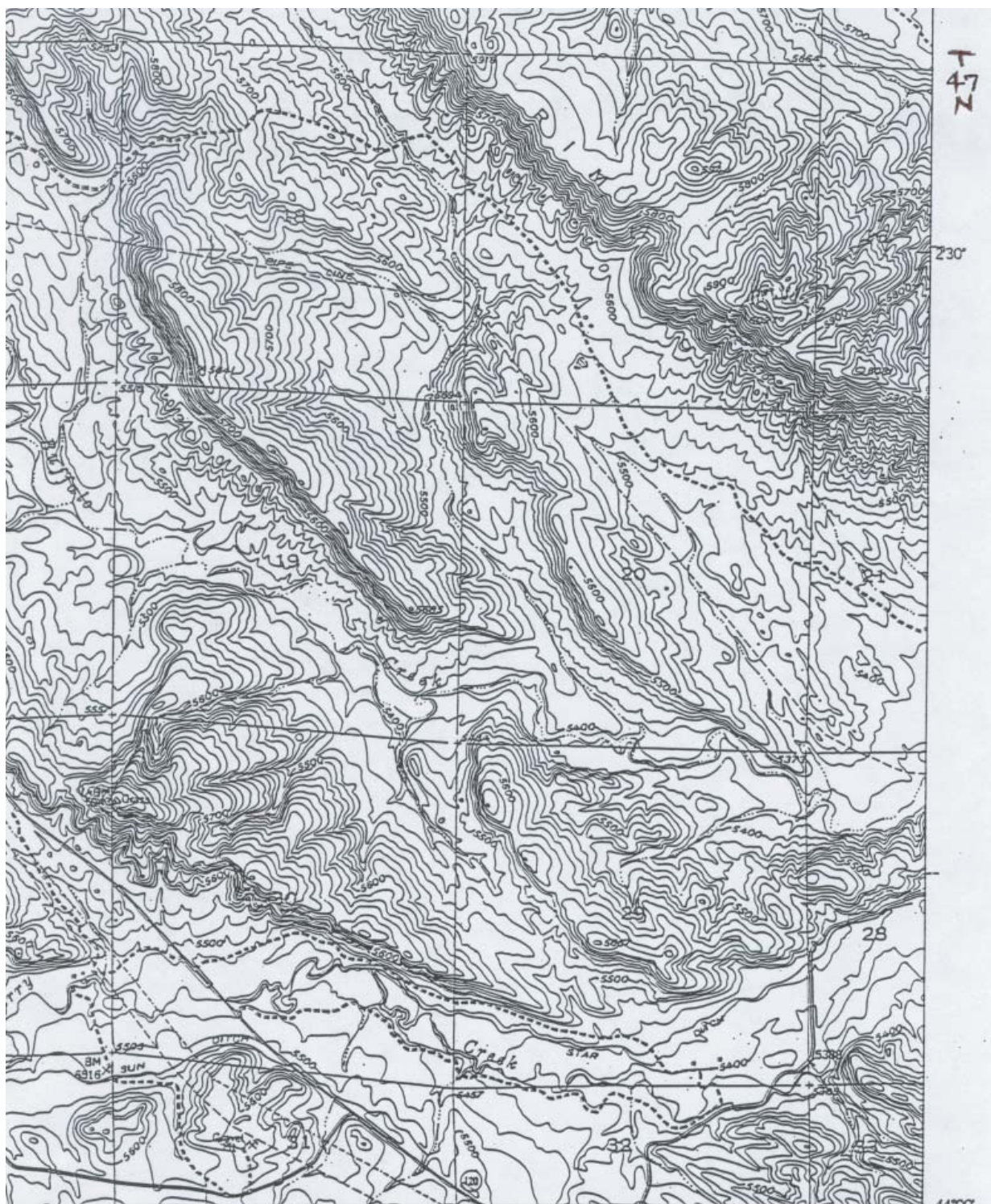
- A) An operation to determine the angle from which a bit has drifted from the vertical during drilling. There are two basic survey instruments: one reveals the angle of deviation only; the other indicates both the angle and azimuth.
- B) A small enclosure on the rig floor used as an office for the driller or as a storehouse for small items. Any small building used as an office or for storage.
- C) The inclination of the wellbore from vertical. The angle of deviation, angle of drift, or drift angle is the angle in degrees that the wellbore differs from the vertical.
- D) A tubular device from 25 to 60 feet long run at the bottom of the drill pipe in place of a bit to recover a formation.
- E) A cylinder around which wire rope is wound in the drawworks.
- F) A device fitted to the rotary table through which the kelly passes and by means of which the torque of the rotary table is transmitted to the kelly and the drill stem.
- G) A rack that supports stands of pipe being stacked in the derrick or mast.
- H) Clamps that grip a stand, or column of casing, tubing, or drill pipe so that the stand can be raised or lowered into the hole.
- I) Preventing the passage of fluid. A formation may be porous yet impermeable if there is an absence of connecting passages between the voids within it.
- J) The gathering of data on a formation to determine its potential productivity before installing casing in a well. The tool is lowered to bottom on a string of drill pipe and the packer set, isolating the formation to be tested from the formations above and supporting the fluid column above the packer.
- K) A systematic recording of data to obtain various characteristics of downhole formations.
- L) In drilling, to assemble the blowout preventer stack on the wellhead at the surface.
- M) To begin drilling operations by a process of moving the drill stem up and down before actually drilling by rotating the drill pipe.
- N) A measure of the ease with which fluids can flow through a porous rock. The fluid conductivity of a porous medium. The ability of a fluid to flow within the interconnected pore network of a porous medium.
- O) A state of voids or open spaces existing in rock.
- P) A granular substance (as sand grains, glass beads, or other material) carried in suspension by the fracturing fluid that serves to keep the fracture open when the fracturing fluid is withdrawn after a fracture treatment.
- Q) A hole in the rig floor from 30 to 35 feet deep, lined with casing that projects above the floor, into which the kelly and swivel are placed when hoisting operations are in progress.
- R) To pull out and subsequently run back into the hole a string of drill pipe or tubing.

- S) A fishing tool attached to tubing or drill pipe and lowered over the outside wall of pipe that is lost or stuck in the wellbore. A friction device, either a basket or a spiral grapple, firmly grips the pipe allowing the fish to be pulled from the hole.
- T) Metering device for the sale of oil from lease to pipeline.
- U) An opening through the rig floor, usually lined with pipe, into which a length of drill pipe is placed temporarily for later connection to the drill string.
- V) An uncontrolled flow of gas, oil or other well fluids into the atmosphere. A blowout or gusher can occur when formation fluids enter the wellbore and steps are not taken to stop the entry of fluids. A kick warns of an impending blowout.
- W) A drilling method in which the hole is drilled by a sharply pointed bit attached to a cable on the bottom of the hole. The bit is attached to a cable, and the cable is picked up and dropped, picked up and dropped, over and over, as the hole is drilled.
- X) The entire length of casing, tubing, or drill pipe run into a hole.
- Y) A device secured around the casing at regular intervals to center it in the hole to allow a more uniform cement sheath to form around the pipe.
- Z) Equipment installed at the wellhead at surface level on land rigs and on the seafloor of floating offshore rigs to prevent the escape of pressure, either in the annular space between the casing and drill pipe or in an open hole during drilling completion operations.
- AA) A short, heavy, hollow, cylindrical steel section with rounded bottom, which is placed on the end of the casing string to serve as a reinforcement and to aid in cutting off minor projections from the borehole wall as the casing is being lowered.
- BB) A pit in the ground to provide additional height between the rig floor and the wellhead to accommodate the installation of blowout preventers, rathole, or mousehole. It also collects drainage water and other fluids for subsequent disposal.
- CC) During a cementing operation, the rising of cement between the casing and borehole wall when the slurry fails to rise uniformly throughout the annulus.
- DD) The control valves, pressure gauges, and chokes assembled at the top of a well to control the flow of oil and gas after the well has been drilled and completed.
- EE) The movement of drilling fluid out of the mud pits, down the drill stem, up the annulus, and back to the mud pits.
- FF) A short string of large-diameter casing used to keep the top of the wellbore open and to provide means of conveying the upflowing drilling fluid from the wellbore to mud pit.

Section Fourteen: Topographic Map

The following page contains a portion of a 7 1/2-minute topographic map.

- 1) What is the contour interval of the map? (Best example is found in the NW 1/4 of Section 20)
 - a) 10 feet
 - b) 20 feet
 - c) 50 feet
 - d) 100 feet
 - e) 1 mile
- 2) What do the small +(plus) signs at the intersection of section corners mean?
- 3) Locate the NW1/4 SE1/4, Section 19, Township 47 North, Range 98 West. Place an X as near to that location as you can.
- 4) What is the highest elevation in Section 17?
- 5) When the contour lines are close together, what is that an indication of?
- 6) Is the longitude and latitude shown on the map? If so, what is the SE1/4 corner of the map?
- 7) The scale of the map is one inch equals:
 - a) 500 feet
 - b) 1000 feet
 - c) 2000 feet
 - d) one mile
 - e) 10 miles
- 8) Assuming Section 20 is a standard section, how many acres does section 20 contain?
 - a) 320
 - b) 400
 - c) 640
 - d) 800
 - e) 1000



R. 99 W. R. 98 W.

1 Section = 1 mile

1 mile = 5,280'

On this map 1 Section = 2.64"

108°37'30"

44°00'

108°37'30"

Section Fifteen: Seismic Activity

The following page contains a portion of a 7 1/2-minute topographic map.

- 1) Geophysical seismic data acquisition, as used in oil and gas exploration, is a science in which _____ are introduced into the ground in an attempt to map the subsurface geologic layers and identify potential oil and/or gas bearing traps and formations.
 - a) X-rays
 - b) Gamma Rays
 - c) Acoustic Waves
 - d) All of the above

- 2) The seismic data acquisition technique in which shock waves are introduced into the surface of the earth by means of a series of large vehicles with pads that are lowered to the ground and shake, or vibrate, is called:
 - a) Dynoseis
 - b) Vibroseis
 - c) Poulter
 - d) Shake and Bake

- 3) The seismic data acquisition technique that produces acoustic waves which are transmitted into the earth's surface by means of the detonation of a series of explosive charges laid out in patterns, either on the ground, or on wooden lath just above the ground, and generally connected by detonation cord is referred to as the _____ method.
 - a) Dynoseis
 - b) Vibroseis
 - c) Poulter
 - d) Hit and miss

- 4) The seismic data acquisition method in which a bore hole is drilled, loaded with an explosive charge, and then detonated, is known as:
 - a) Dynoseis
 - b) Vibroseis
 - c) Poulter
 - d) The way they do it down south

- 5) Of the three most commonly used energy sources implemented in geophysical seismic data acquisition, the method that will more greatly impact near surface water bearing aquifers is:
- a) Dynoseis
 - b) Vibroseis
 - c) Poulter
- 6) The science used in geophysical seismic exploration is very similar to the technology used in a common well logging practice. This type of well log is known as:
- a) Gamma Ray
 - b) Neutron
 - c) Acoustic Bond Log
- 7) The electronic receivers that pick up reflections of the acoustic waves created by the seismic energy source, after the waves have “bounced” off of subsurface strata and returned to the surface of the earth, are called:
- a) Transducers
 - b) Capacitors
 - c) Geophones
 - d) Juggles
- 8) Another use of seismic technology, besides the exploration for oil and gas is the detection of:
- a) Solar flares
 - b) Political campaigns
 - c) Aunt Bertha's arrival
 - d) Earthquakes and tidal waves
 - e) All of the above
- 9) Seismic operations are usually conducted in hospitals.
- a) True
 - b) False

Governing Authority

The IOGCC Council of State Regulatory Officials maintains jurisdiction over the testing and certification criteria and has oversight in the development of the national standards. The authority to grant and withdraw certification is vested in the IOGCC.

Evidence of certification will be an official document signed by an officer of the IOGCC, embossed with the IOGCC seal.

Certification by the IOGCC is not intended to obstruct or assume the authority of states to control and manage their respective oil and gas regulatory programs and personnel.

Who We Are

The Interstate Oil and Gas Compact Commission represents the governors of 37 states – 30 member and seven associate states – that produce virtually all oil and natural gas in the United States. Seven international affiliates have been accepted into the organization, giving the IOGCC a voice in global energy affairs.

The organization's mission is to champion the conservation and efficient recovery of our nation's oil and natural gas resources while protecting health, safety and the environment.

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National



Inspector



Certification

Program



Interstate Oil and Gas
Compact Commission

About the Program

The National Inspector Certification Program, instituted in 2000 by the Interstate Oil and Gas Compact Commission, establishes national standards for state regulatory agencies to certify personnel responsible for inspecting oil and gas wells.

Due to inherent differences in geology, site characteristics, weather, operations, organizational structure and stage of development of each state, the certification program includes mandatory criteria applicable to all states, with an option for testing on state specific standards.

To find out if your state currently offers the exam, log onto www.iogcc.state.ok.us/CSRO/CSROMainPage.htm.

Program Benefits

- Establishes a nationwide level of expertise among state oil and gas field inspectors and technicians
- Illustrates state recognition of the importance of the regulatory process
- Sets guidelines and structures that are consistent state-to-state
- Provides the opportunity to test on state specific regulations
- Creates a consistent knowledge base for all state oil and gas regulators and field technicians that sets the standard among state regulatory agencies.
- Provides a base for states to build upon, encouraging them to initiate training programs and sub-certifications.

Exam Requirements

The program requires that applicants have a strong knowledge base and a minimum of one year experience as a regulator prior to applying for certification.

Applicants must meet one of the following four criteria to submit an application for certification:

- Four-year college degree, plus one year of oil and gas experience
- Two-year college degree, plus five years of oil and gas experience
- Ten years of oil and gas experience
- Five years of regulatory experience, plus five years of oil and gas experience

Supplemental education or training may be substituted for formal education and experience at the discretion of the state oil and gas director.

Additional Information

If you are interested in the National Inspector Certification Program, please contact your state oil and gas director who must approve all applicants prior to testing. If your state currently does not participate in the program, contact the IOGCC at (405) 525-3556.

Testimonial

“I have found the oil and gas inspectors at the Oklahoma Corporation Commission eager to demonstrate their knowledge and skills by taking the IOGCC inspector certification exam. The IOGCC certification program not only provides a formal means of recognizing the inspectors’ expertise, but also establishes the basis for awarding them a bonus in pay.”

Lori Wrotenbery, Oil and Gas Division director
Oklahoma Corporation Commission

Certification Exam

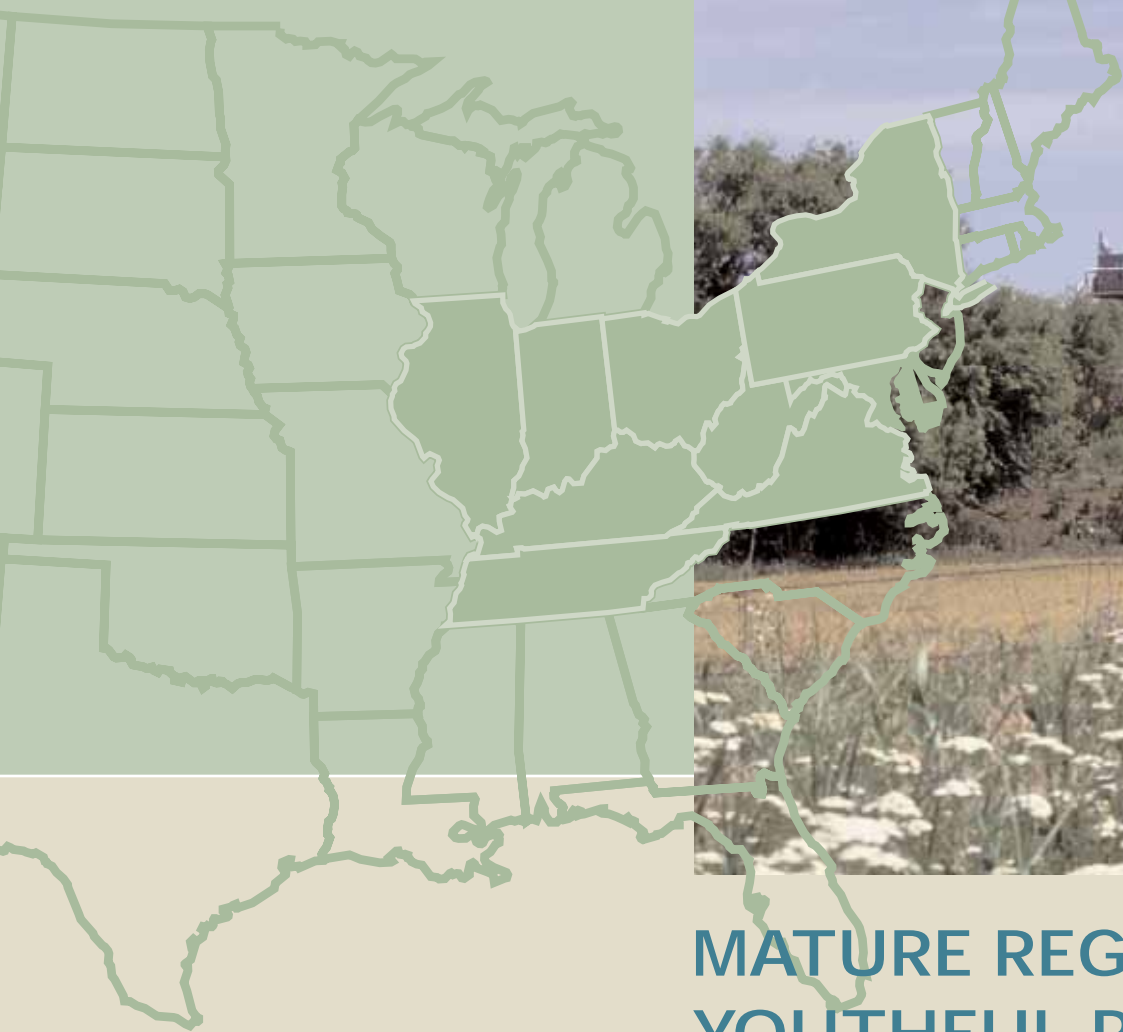
The National Inspector Certification Program examination, which is provided free of charge, is two hours in length and requires a score of at least 70% to become certified. The examination consists of multiple choice, fill-in-the-blank, illustration, diagram, and true/false questions. Topics include, but are not limited to:

- | | |
|---|--|
| ▪ Drilling procedures | ▪ Required performance objectives |
| ▪ Cementing procedures | ▪ Oilfield terminology |
| ▪ Site and pit selection | ▪ Topographic maps |
| ▪ Well completion procedures | ▪ Seismic activity |
| ▪ Underground injection | ▪ Illustrations and diagrams pertaining to drilling rigs |
| ▪ Production | ▪ Drill stem tests |
| ▪ Hydrogen sulfide | ▪ Lease production sites |
| ▪ Pollution prevention | |
| ▪ Naturally Occurring Radioactive Material (NORM) | |
| ▪ Plugging procedures | |

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APPENDIX

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MATURE REGION, YOUTHFUL POTENTIAL

Oil and Natural Gas Resources in the
Appalachian and Illinois Basins

*A Report by the Appalachian and Illinois Basin Directors
of the Interstate Oil and Gas Compact Commission*

The United States is the world's third-largest producer of oil and second-largest producer of natural gas. Prospects for future production from the Appalachian and Illinois basins remain promising, despite the maturity of these basins. The Appalachian basin occupies more than 180,000 square miles, while the Illinois basin encompasses approximately 53,000 square miles. Together, these basins span 10 states — Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia, Tennessee, Illinois, and Indiana.



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This report was developed by the Appalachian and Illinois Basin Directors in cooperation with the Interstate Oil and Gas Compact Commission (IOGCC) and the U.S. Department of Energy's Office of Fossil Energy and National Energy Technology Laboratory. It is intended to serve as a reference source for government and industry decision makers.

The IOGCC represents the governors of 30 member and 7 associate member states. The IOGCC's mission is to promote conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. The group offers a forum for government, industry, environmentalists, and others to share information and viewpoints.



Overview

Secure energy for the nation, economic benefits for Eastern states

Making optimal use of available domestic fossil fuel resources is key to ensuring adequate supplies of energy for American consumers. This imperative has brought renewed focus to the significant oil and natural gas resources still remaining in America's oldest producing areas: the Appalachian and Illinois basins.

As our nation's appetite for oil and natural gas continues to grow, so does our dependence on imports. During the past three decades, U.S. demand for crude oil and natural gas has increased steadily while domestic production has declined (crude oil) or remained flat (natural gas). The gap between domestic supply and demand is expected to continue growing, potentially resulting in even greater dependence on imports in the future.

Our "most drilled but least explored" basins deserve a fresh look. After more than a century, the Appalachian and Illinois basins still contain at least as much oil and natural gas as have been produced to date. Estimates of remaining technically recoverable resources, including proved reserves, are in the range of 4.8 billion barrels of oil and 79 to 96 trillion cubic feet of natural gas. The majority of remaining hydrocarbon resources in these basins exists in unconventional settings – primarily in coal seams, Devonian-age shales, and low-permeability (tight) gas sands – and previously untapped deeper formations. In the longer term, the basins could also provide further hydrocarbon resources from oil sands and oil shale. In the future, with their large untapped potential resources and proximity to major markets, the basins are positioned for an important role in increasing America's energy security.

New plays are attracting heightened interest in exploration and production in the region. Applying new technology and concepts is resulting in a wide range of new activities in the basins. *Coalbed natural gas* – a plentiful resource throughout both basins – is being pursued economically using conventional drilling and completion techniques as well as advanced multilateral technology and horizontal drilling. Advanced geophysical analyses and drilling cost reductions are enabling operators in several areas to take another look at the deep *Trenton/Black River play*, which extends through both basins. New reservoir stimulation and horizontal drilling are enabling operators to revisit old shale (like the *New Albany Shale*) and tight gas sand (such as the *Clinton/Medina*) plays, and 3D seismic is helping in the pursuit of untapped hydrocarbon resources in *pinnacle reefs*.



Eastern states already benefit significantly from regional oil and natural gas production.

States in the region are highly dependent on oil and gas production for revenues from severance and state corporate income taxes. In 2004, oil and gas production in the basins was valued at \$5.9 billion, and with rising prices, this value has continued to increase. Throughout the entire value chain from initial development and production to end use, income and investment related to the oil and natural gas industry are critical components of the region's economic vitality. Many believe that production in the Appalachian and Illinois basins can be reinvigorated, yielding substantial returns to regional economies in the Eastern states as well as to the nation's economic and energy security. Nearly 375,000 people are employed in the oil and natural gas industry in the Appalachian and Illinois basins states, and regional industries employing millions more rely on these fuels for feedstocks or process heat.



Pathway to rejuvenating the basins

Collaborative basin-wide strategies, driven by public-private partnerships as well as state governments, will be essential to bringing more of the region's vital oil and natural gas resources to market. Five prerequisites must be addressed, using strategies such as those outlined below:

Prerequisite 1: Technology progress

- ✓ Extending the life of existing wells and fields through advanced technology
- ✓ Improving fracture detection
- ✓ Applying more advanced 3D seismic imaging
- ✓ Tapping unexplored deep reservoirs through new drilling and completion techniques
- ✓ Exploiting opportunities to develop coalbed natural gas and other unconventional resources
- ✓ Expanding use of advanced enhanced recovery techniques
- ✓ Supporting technology transfer across the region
- ✓ Stimulating investment opportunities

Prerequisite 2: Access to resources

- ✓ Increasing access to resources on public lands in an environmentally sound manner
- ✓ Resolving mineral rights conflicts between coal and oil and natural gas resources
- ✓ Addressing the unique access issues in urban and suburban areas
- ✓ Implementing energy education programs to increase public understanding of oil and gas operations

Prerequisite 3: Infrastructure expansion

- ✓ Expanding pipeline capacity
- ✓ Expanding natural gas storage capabilities
- ✓ Improving the capacity of gas gathering and processing

Prerequisite 4: Access to high-quality data

- ✓ Public-private partnerships between geologic surveys, other state agencies, and industry
- ✓ Continuing innovation in data management, e.g., risk-based data management system

Prerequisite 5: Environmental stewardship

- ✓ Strong and responsive regulatory programs
- ✓ Cost-effective regulatory strategies
- ✓ Continuing oil field and pipeline emergency response programs and training
- ✓ Communication among state and federal regulatory agencies to improve program efficiency and effectiveness

The Opportunity

Taking a second look at the “most drilled, least explored” basins in the world

The Appalachian and Illinois basins – the birthplace of the modern petroleum industry – are probably the most extensively drilled and mature hydrocarbon basins in the world. Does this mean that oil and natural gas resources from the region have been exhausted? The answer is a resounding *no*. The Appalachian and Illinois basins are mature, yet they still have a youthful potential. Oil and gas explorer Richard Beardsley, a geologist with extensive experience in the Appalachian basin, calls it the “most drilled and least explored” basin in the world.¹

Annual oil production for most Appalachian and Illinois basin states peaked before 1910, and overall natural gas production in the region began to decline around 1930. Notable exceptions include Virginia, where coalbed natural gas production began in 1990 and has increased every year since, and Kentucky, where gas production has recently peaked, growing steadily since reaching a low in 1983.

This recent natural gas production hints at the remaining potential of the region. So do recent resource discoveries in the Trenton/Black River formations in New York and West Virginia, the coalbed natural gas potential throughout the region, new production from the New Albany Shale gas play in southern Indiana and northern Kentucky, oil discoveries in pinnacle reef formations, resources in tight gas sands, and the potential application of carbon dioxide injection to enhance oil recovery in old oil fields. All are clear signs that as far as future oil and gas production potential in the Appalachian and Illinois basins is concerned, the story may be far from over.

Cumulatively, the basins have produced more than 5 billion barrels (BBbl) of oil and 50 trillion cubic feet (Tcf) of natural gas. Yet after more than a century of production, equal or greater quantities of resources are still waiting to be tapped. The Appalachian basin is the largest onshore basin in the United States in terms of area, and much of the basin remains relatively unexplored. While determining the extent of hydrocarbons in the basins is not an exact science, current estimates of remaining technically recoverable resources (including proved reserves) are in the range of 4.8 BBbl of oil and 79 to 96 Tcf of natural gas.

What are an Mcf, MMcf, Bcf, and Tcf?

Natural gas is sold in units of a thousand cubic feet (Mcf, using the Roman numeral for one thousand). Units of a million cubic feet (MMcf), billion cubic feet (Bcf), or trillion cubic feet (Tcf) are used to measure larger quantities. The United States currently consumes about 22 Tcf annually. A Tcf is enough natural gas to:

- Heat 15 million homes for one year
- Generate 100 billion kilowatt-hours of electricity
- Fuel 12 million natural-gas-fired vehicles for one year

How much is a Bbl?

A barrel (Bbl) of crude oil or natural gas liquids is equal to 42 U.S. gallons. The United States currently consumes about 20 million barrels (MMBbl) of oil per day, or 7.3 billion barrels (BBbl) per year.

What is a play?

A play is a set of known or postulated natural gas or oil accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.

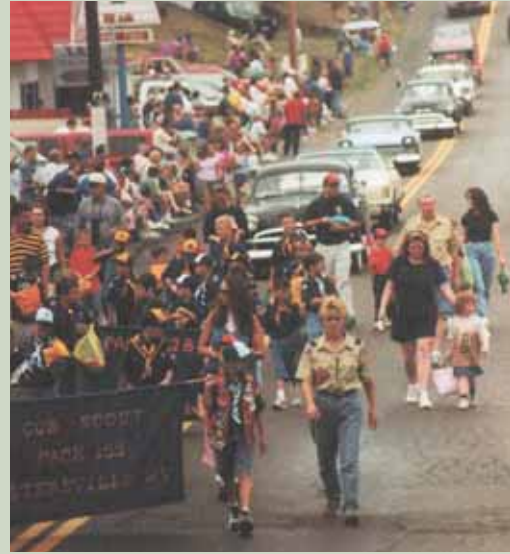
Top 3 misconceptions about the Appalachian and Illinois basins

3. Oil and gas in the basins have little impact on jobs or economic growth.
2. The basins are played out and are not attractive for investment.
1. The basins are no longer important to the nation's energy future.

Birthplace of the nation's natural gas production

The discovery of natural gas in the United States was an accident. Appalachian salt miners struck oil instead of salt in Ohio in 1814, and gas instead of salt a year later in West Virginia. The first intentional attempt to find natural gas occurred in 1821 near Fredonia, New York, drilling to a depth of 70 feet. Fredonia gas was sold to nearby hotels and businesses, and lit local streetlamps. In the years that followed, new uses were found for the natural gas so readily produced from the ground. Natural gas became a desirable fuel for evaporating the brines in the process of salt-making, since oil ruined the quality of the brine and produced salt. Natural gas was also used to dry grain on farms and to fuel steam production plants and steel furnaces. Soon gas was discovered in Pennsylvania (1860), Ohio (1861), and Kentucky (1863). Availability of natural gas in Indiana in the 1880s formed the basis for new industries like glassmaking in the aptly named Gas City.

During this period of American societal and economic growth, the Appalachian and Illinois basins fed a steady stream of gas to the energy-hungry nation. From the late 1880s to 1930, the Trenton field in Ohio and Indiana achieved total production of more than 1.5 Tcf of natural gas.



The annual West Virginia Oil and Gas Festival in Sistersville celebrates the inventive, colorful history of petroleum production in the Appalachian basin.

Home of America's oldest oil wells

The modern oil industry evolved in response to the nation's need to find new ways to keep its lamps lit. At the time, lamp oil was produced from whales in a laborious, expensive, and inhumane process. But a New York lawyer, George H. Bissell, saw potential in "rock oil," a byproduct of salt mining. Bissell purchased a farm in northwestern Pennsylvania and formed an unsuccessful company for surface oil recovery. It wasn't until he met Edwin L. Drake and salt driller "Uncle Billy" Smith that the three decided to try collecting oil by drilling into the Pennsylvania earth.

In 1859 they struck oil at a depth of almost 70 feet, just south of Titusville. They were so far ahead of their time that technology was just being invented to refine what they were withdrawing from the ground. Just 10 years later, 1,186 oil-producing wells had been drilled in the area, and Pennsylvania became the center of the world oil industry. Other states in the region soon began producing oil as well: West Virginia (also in 1859), New York (1865), Kentucky (1865), Ohio (1884), Indiana (1886), and Illinois (1904).



It took a particular kind of individual to work the oil fields, like the "roughnecks" seen above. Below, oil wells dot the landscape in Richburg, New York, in 1883; oil production peaked in the state at 6.5 million barrels a year earlier.

The basins remain rich in undiscovered and “unconventional” resources

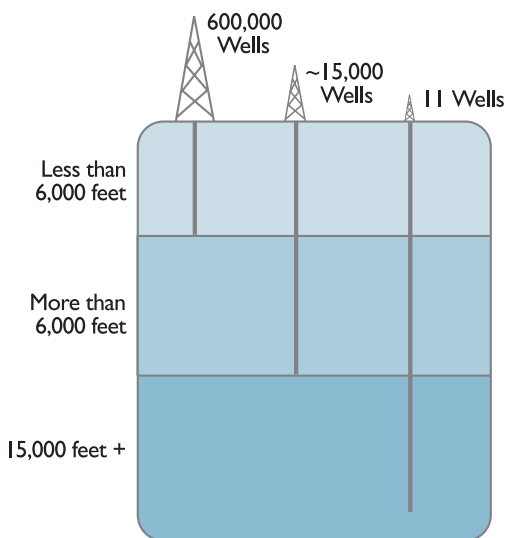
How much of the substantial oil and natural gas resources in the Appalachian and Illinois basins can be recovered economically and with what levels of investment? Making informed estimates requires an understanding of the different categories of resources in the basins and the unique challenges of exploring and producing them.

The resource pyramids on page 7 provide a way to visualize potentially recoverable oil and natural gas in the basins. The hydrocarbons are categorized as layers of successively lower quality, less accessible, more costly, and/or more uncertain resources. The volume of potential resource in each category tends to increase as one moves down the pyramids. As technology and understanding of resources advance, the lower quality, higher cost, more uncertain resources can become more accessible and economical, enabling them to make a larger contribution to future oil and gas supplies.

“Unconventional” natural gas represents, by far, the largest category of estimated remaining hydrocarbon resources in the Appalachian and Illinois basins. Compared to conventional resources, unconventional gas deposits are found in more complex geological settings and often require newer development methods to overcome the limits of traditional production processes. Today, the newer development methods required to produce unconventional gas resources are increasingly being applied. Indeed, approximately two-thirds of the successful gas wells currently drilled annually in the United States are drilled into unconventional settings.

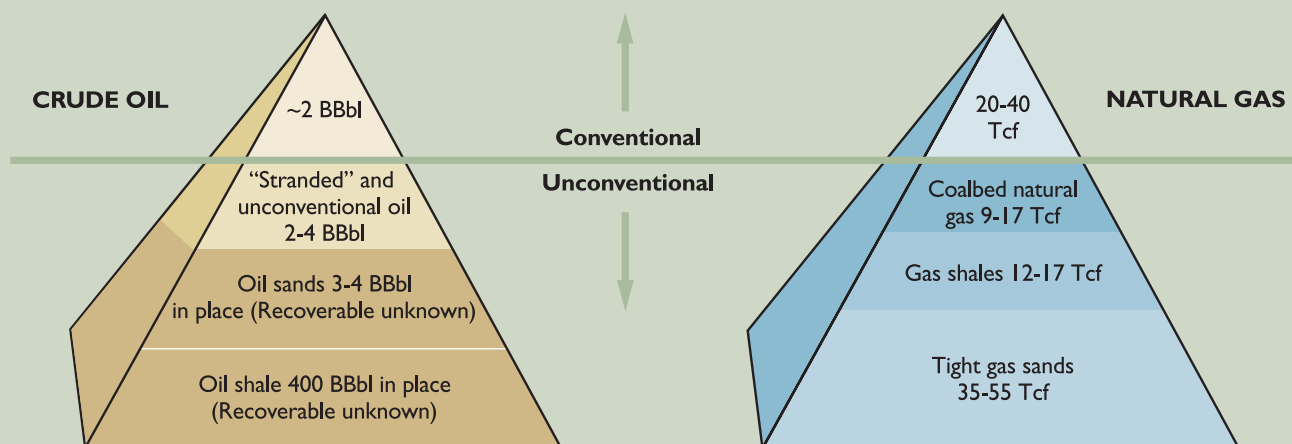
Advances in drilling that allow resources to be identified and produced with lower cost and risk may prove to be particularly valuable in these basins. One promising avenue is directional or horizontal drilling. These technologies allow operators to reach reservoirs up to several miles from the drilling site, so that more resources can be recovered with fewer wells, less waste, and less surface disturbance.

Deep drilling is another technology that can change the face of production in the Appalachian and Illinois basins. Although nearly 600,000 wells have been drilled in these basins over the last century and a half, only a small portion have been drilled deeper than 6,000 feet, leaving potential resources at even greater depths virtually unexplored. The Potential Gas Committee (PGC) estimates that about 10 percent of the undiscovered natural gas resource in the Appalachian basin is deeper than 15,000 feet, representing about 6 Tcf, and it is reasonable to speculate based on regional geology that substantially greater volumes could exist in deeper horizons. With new technologies that reduce the costs and risks of deep drilling, these untapped resources may now be within economic reach of producers.



New frontiers in deep gas
Even though the Appalachian and Illinois basins are mature in terms of shallow production (less than 6,000 feet), they are considered rather young in terms of deeper exploration (more than 15,000 feet). Indeed, according to the Potential Gas Committee, only 10 to 15 percent of the possible hydrocarbon-producing formations within the Appalachian basin have been tested, and only 11 wells have been drilled deeper than 15,000 feet in the basin.² Most wells have been concentrated along established producing trends, and vast areas remain unassessed.

Oil and natural gas technically recoverable resources in the Appalachian and Illinois basins*



CONVENTIONAL RESOURCE ESTIMATES

An estimated 2 BBbl of conventional crude oil remains in the basins, including:

- **Proved reserves.** As of the end of 2003, nearly 0.4 BBbl of proved, producing crude oil and natural gas liquids reserves had been booked in the basins.³
- **Probable/Inferred reserves.** The USGS estimates that there are more than 1.2 BBbl of inferred crude oil and natural gas liquids reserves in the "Eastern Region"⁴ of the United States.
- **Undiscovered resources.** The USGS mean estimates for technically recoverable undiscovered crude oil and natural gas liquids resources in the Appalachian and Illinois basins are nearly 0.4 BBbl, with more than 70 percent in the Illinois basin. This amount is comparable to current proved oil reserves in the two basins.⁵

UNCONVENTIONAL RESOURCE ESTIMATES

Stranded oil resources remain in the ground after traditional primary and secondary oil recovery and can often represent two-thirds of the original resource in place. From 1 to 2 BBbl of stranded oil exists in the basins. Another 2.4 BBbl of liquids is believed to be associated with remaining unconventional gas resources.

PROSPECTIVE FUTURE RESOURCES

Two additional categories of prospective future resources exist in the basins, although the technically recoverable portion of these resources has not been estimated.

- **Oil sands** contain bitumen⁶, the recovery of which requires mining or heating the reservoir. An estimated 3 to 4 BBbl in place of oil sands exist in the Appalachian basin, primarily in Kentucky. With today's technology, little of this resource is economical to recover, but with improved technologies some could be recoverable in the future.⁷
- **Oil shale** refers to kerogen, a hydrocarbon contained in hard rock that requires processing similar to that for oil sands. Resources of oil shale in the eastern United States may exceed 400 BBbl⁸ in place, although the quality of these shales is quite inferior to shales in the West. None of this resource approaches economic viability with today's technology but could represent a future target.

CONVENTIONAL RESOURCE ESTIMATES

An estimated 20 to 40 Tcf of "conventional" natural gas remains in the basins, including:

- **Proved reserves.** As of the end of 2003, 11 Tcf of natural gas reserves had been booked in the Appalachian and Illinois basins.
- **Probable/Inferred reserves.** The USGS estimates that there are 3.7 Tcf of inferred natural gas reserves in the "Eastern Region" of the United States. In contrast, the PGC estimates that probable natural gas resources in Appalachian and Illinois basins are on the order of 20 Tcf, while the National Petroleum Council estimates potential reserves growth in its Eastern Region to be on the order of 5 Tcf.⁹
- **Undiscovered resources.** The USGS mean estimate for undiscovered conventional natural gas resources for the two basins is estimated to be 4.8 Tcf, with the vast majority in the Appalachian basin. This represents about 50 percent of current proved reserves in the two basins.

UNCONVENTIONAL RESOURCE ESTIMATES

Unconventional natural gas resources have been produced throughout the oil and gas development history in these basins, though their full potential is far from being realized. With today's technologies and improving market conditions, production of these resources — including gas in "tight" sandstones, gas shales, coalbed gas, and other continuous-type deposits — is becoming more attractive. Unconventional resources represent, by far, the largest proportion of the natural gas resource remaining in the basins, amounting to 61 to 76 Tcf of technically recoverable natural gas (see table on page 9).

Definitions

"Proved reserves" are demonstrated with reasonable certainty — based on geologic evidence — to be profitably recoverable in the future from known reservoirs.

"Probable/Inferred reserves" (reserve growth) are assumed to be recoverable with additional development of discovered fields.

"Undiscovered conventional resources" are postulated to exist outside of known oil and/or gas fields based on geologic information and theory, and are contained in discrete accumulations from which oil and/or gas can be extracted using traditional development practices.

*Note: Resource categorizations here expand upon those shown in the table on page 9. Included here are new resource categories (stranded oil, oil sands, and oil shale) not included in the table.

Challenges of estimating oil and natural gas resources

Oil and natural gas resource estimates change continually in response to advances in geologic knowledge, exploration and recovery technology, and the economic and policy conditions under which exploration and production are expected to occur. Accurate and timely assessments of the nation's potential resources are essential to ensure that public policy is based on sound information.

Estimates of resources in the Appalachian and Illinois basins are particularly uncertain. One factor contributing to the uncertainty is the limited availability of data on past production and on the characteristics of prospective plays. A second unknown is the potential impact of technology progress. Resource assessments typically assume that only current technology, or incremental improvements on that technology, will be available to recover resources. Throughout the history of these basins, technological leaps have helped industry to pursue resources previously thought unproductive or have helped to reduce exploration and production costs, creating large and unexpected additions to recoverable resources.

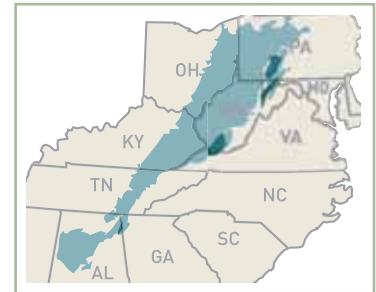
See the table on page 9 for a range of current resource estimates for the Appalachian and Illinois basins.

Several plays are attracting new interest in the basins

Most of the plays generating renewed interest in the Appalachian and Illinois basins are in challenging geological formations – including coal seams, tight gas sands, and gas shales – or in deep horizons. Several specific plays of interest are profiled below.

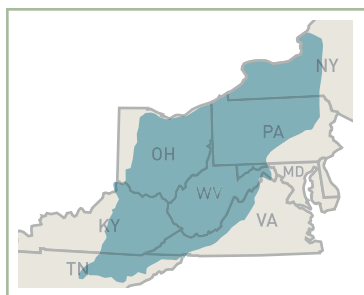
Coalbed natural gas

Coalbed natural gas is a plentiful resource throughout both the Appalachian and Illinois basins that has attracted renewed attention in the last decade. Coal production has been established here for more than a century, with both shallow and deep coal deposits distributed extensively throughout both basins. Since the late 1970s, thousands of coalbed natural gas wells have been drilled in these basins. Today, advances in horizontal drilling, completion, and production technology make it increasingly possible to pursue coalbed natural gas as a separate product. For example, coalbed natural gas from approximately 1,200 acres can be produced using horizontal and pinnate drilling technology from only 2 or 3 surface wells, in contrast to the 50 conventional vertical wells that would have been required with previous technology. Advances in water handling and treatment systems also make coalbed gas production economic today in areas that could not have been developed just 10 years ago.



Penn Virginia Oil and Gas Corporation is using horizontal well and pinnate drilling technology to add more than 300 Bcf of reserves in West Virginia. Horizontal/Multilateral pinnate completion technology, pioneered by CDX Gas LLC, is being applied as an alternative to conventional hydraulic fracturing to stimulate production from low-permeability continuous reservoirs like coals (and in the future, perhaps, also gas shales). The company has added reserves at an annual growth rate of 25 percent consistently over the last five years – in a basin many believed to be mature with limited potential. In their core areas, a typical well produces from 150 to 200 Mcf per day. Horizontal wells, while costing four times more than traditional vertical wells in this area, can produce gas at 10 times the rate of vertical wells.¹⁰

Trenton/Black River



The deep Trenton/Black River play extends through parts of New York, West Virginia, Ohio, Kentucky, Tennessee, Pennsylvania, and Ontario, Canada. A multistate study is under way to assess the geologic extent and exploratory potential of this play across the Appalachian and Illinois basins.¹¹

Recent discoveries have generated renewed interest in the oil and natural gas potential of this play in the Appalachian basin. Commercial production requires an ability to detect fractures that could enhance matrix permeability and serve as flow pathways. Advanced geophysical analyses, including 3D seismic data acquisition, attribute analyses, new logging techniques, and seismic modeling, coupled with integrated models incorporating all available geologic and geophysical data, are helping to identify the most promising prospects in this play.

Fortuna Energy, a wholly owned subsidiary of Canadian-based Talisman Energy, has brought its track record in horizontal drilling and in the Trenton/Black River north of the border to the Finger Lakes region of New York. The first two wells completed by Fortuna tested at 2.4 MMcf per day and 10.4 MMcf per day.¹² Another well drilled to a depth of 10,100 feet tested in excess of 18 MMcf per day. Some wells drilled into this trend are, in fact, among the highest producing in the eastern United States. A well drilled by Columbia Natural Resources LLC in West Virginia in 1999 flowed 50 MMcf per day¹³, and another drilled in the Finger Lakes region located reserves estimated at 20 Bcf.¹⁴ In 2000, a well drilled by Pennsylvania General Energy Corporation in Steuben County, New York, produced at an average rate of nearly 3 MMcf per day its first year. More recently, Fortuna drilled a vertical well – which was then steered horizontally – to a depth of 12,050 feet that tested at a choked rate of 19 MMcf/day. The well was brought on stream at a rate of 34 MMcf/day and had produced 5.3 Bcf by November 2004.¹⁵



Through year-end 2004, New York's Trenton/Black River wells produced more than 110 Bcf of natural gas.

Various Estimates of Technically Recoverable Resources in the Appalachian and Illinois Basins

	Crude Oil & Natural Gas Liquids (BBbl)	Natural Gas (Tcf)			
	U.S. Geological Survey (USGS)	U.S. Geological Survey (USGS)	Potential Gas Committee (PGC)	National Petroleum Council (NPC)	Advanced Resources International (ARI)
Proved reserves (1)	0.400	10.9	10.9	14.0	*
Probable/Inferred (2)	1.200	3.7	19.8	5.0	*
Undiscovered conventional (3)	0.353	4.8	*	15.0	*
Unconventional coalbed	-	10.0	16.8	9.8	9.1
Tight gas sands (3)	2.737	45.5	31.2	34.7	55.2
Gas shales (3)	0.096	15.4	*	17.0	12.0
Unconventional subtotal	2.833	70.9	48.0	61.5	76.3
Total remaining resources	4.786	90.3	78.7	95.5	-

1 Proved reserves for oil include Illinois, Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia. For gas, estimates include Kentucky, New York, Ohio, Pennsylvania, Virginia, and West Virginia.

2 USGS and NPC estimates for inferred reserves are for Eastern Interior, which includes the Appalachian and Illinois basins, and the Michigan and Black Warrior basins.

3 PGC estimates for conventional also include primarily tight gas and gas shales.

* Not estimated separately.

Pinnacle reefs

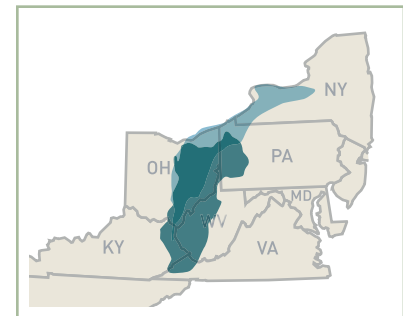
Pinnacle reefs also hold potential in the Appalachian and Illinois basins. Coral reefs that grew in warm shallow seas and were buried over time provided formations within which hydrocarbons could accumulate. Approximately 80 pinnacle reefs have been discovered in the Illinois basin in Indiana and Illinois. Some of the reservoir structures were formations overlying the actual reef rock, while in other cases, the reef rock itself is the reservoir.



Many of these reservoirs have been found by chance – traditional efforts to establish methods to predict the trend in these reefs were often not successful. More recently, improved technology and more systematic, stratigraphic test well programs are resulting in more success. An exploration well drilled in Marion County, Illinois, by Tulsa-based Ceja Corporation found a pinnacle reef that may be the largest modern oil field in Illinois. This deep structure underlies the Miletus field and was identified by reprocessing old seismic data with new technologies. Ceja deepened an existing well to test the reef, and the well produced 70 barrels per day. Ultimate reserves resulting from delineation drilling are now estimated to be 5 to 6 million barrels.¹⁶ Recent approvals by the Illinois Department of Natural Resources to apply seismic imaging along an abandoned pipeline right-of-way in the Stephen A. Forbes State Park, just south of the Miletus discovery, where access had previously been denied, may help in the discovery of similar fields.

Tight gas sands

Although believed to be quite mature, tight gas sands in the Appalachian basin remain a potentially substantial source of future gas supplies. More than 9 Tcf have been produced to date from more than 75,000 wells in this basin, the birthplace of U.S. tight gas production. Future reserves are estimated to be on the order of 3 Tcf. Tight gas plays primarily include the Clinton/Medina, Berea, and Oriskany. Most of the current drilling in Pennsylvania and West Virginia is targeting tight gas formations. These plays are now being targeted by several companies. For example, Range Resources Corporation is accelerating its shallow tight sand development program in Appalachia in 2005 with 48 wells planned for the year.



Shale gas

The New Albany Shale and other Devonian shales are other resources that are sparking renewed interest. Since the early 1860s, more than 600 wells have been drilled into the New Albany Shale in Indiana and Kentucky. Recent success in the Antrim shales of the Michigan basin may bode well for renewed production in the New Albany, whose characteristics are very similar. With as much as 1.9 Tcf of technically recoverable reserves estimated to exist in the New Albany¹⁷, several companies are now consolidating large lease blocks or obtaining permits to produce gas from this play. Companies successfully drilling New Albany wells in Kentucky include Inexco Oil Company (Butler County) and Endeavor Energy Resources LP (Breckinridge County), with Quicksilver Resources (Meade County) and El Paso Production Co. (Davies County) having success in Indiana.^{18, 19}

Production from the New Albany Shale depends on the number of fractures encountered by a well bore or through stimulation or artificial fracturing. Technologies to verify fracture geometry and intersect multiple fractures using horizontal drilling or hydraulic stimulation will have a significant impact on the viability and productivity of the shale. One barrier to New Albany gas production lies in the shortage of infrastructure for gathering, compression, and processing to move the resources to market through the interstate gas transmission network. Although Indiana has a substantial interstate pipeline system, the availability of feeder system pipelines to carry New Albany gas is limited. To date, the largest production from New Albany has occurred in an area where a single end user was willing to pipe the gas from a field to their facility.

Oil sands and oil shale

Heavy oil, oil sands, and oil shale are also large resources in the Appalachian basin that could add to domestic supplies in the longer term. For example, 3 to 4 BBbl of oil in place exists in oil sands, primarily in Kentucky. The adaptation of new technologies being tested in Canada, such as SAGD (steam assisted gravity drainage), VAPEX (the use of a combination of solvent and heat), and the “top down combustion” process, could help unlock the potential of oil sands. Another new technology being developed uses down-hole heating elements and “ice” barriers to potentially produce oil from oil shale in an economical and environmentally acceptable manner.²⁰



After drilling, the site is reclaimed, and the well head and fluid separation and/or compression equipment may be all that remain in the rural landscape.

Eastern states benefit significantly from natural gas and oil production

Oil and natural gas production from the Appalachian and Illinois basins not only makes important contributions to the nation's domestic energy portfolio; it also creates significant positive impacts on the regional economies of Eastern states.

One of the obvious benefits is **job creation**, which occurs all along the oil and natural gas “value chain” – from exploration and production, to oil refining and gas processing, to transportation and storage, all the way through to oil and gas distribution and retailing.

Other benefits include the **direct expenditures** associated with oil and gas industry activity and the **revenues** state governments collect from severance and corporate income taxes on oil and gas

production. In 2003 the Appalachian and Illinois basins states received approximately \$35 million in state production taxes. Oil and gas activities on state lands yield additional revenues. For example, from 1947 to 2002, receipts to the state of Pennsylvania from leases for gas storage and oil and gas production amounted to more than \$133 million.²¹

Less obvious are the **indirect economic benefits to businesses and consumers** of regionally produced energy, particularly natural gas. For every million dollars invested in oil and gas development, about three direct industry jobs are created or sustained, with another three to four indirect jobs per direct job. Moreover, almost every industry, business, and homeowner uses natural gas these days, and natural gas is increasingly used for power generation in the region. These markets depend on reliable supplies at a time when domestic natural gas production is not keeping pace with demand. According to the Energy Information Administration (EIA), consumption of natural gas in the United States will increase to more than 30 Tcf annually by 2025, but domestic production will increase only slightly to approximately 22 Tcf annually. As the discrepancy between domestic supply and demand grows, gas produced in the Appalachian and Illinois basins will make an ever-more-vital contribution to the economies of Eastern states.



Pittsburgh is among the large population and industrial centers in the Appalachian and Illinois basins. These centers consume a much higher percentage of natural gas than they produce.

Oil and Natural Gas in the Appalachian and Illinois basins states²²

	Production					Employment				
	Active Wells (2004)		Annual Production (2004)		Market Value (2004)	Total Jobs	Oil/Gas Extraction	Refining	Transportation	Wholesale & Retail
	Oil	Gas	Oil (Thousand Bbl)	Gas (MMcf)	(\$ Million)					
Illinois	31,860	240	11,696	126	\$450	45,678	2,111	7,110	6,120	30,337
Indiana	5,385	919	1,755	3,401	\$91	32,663	391	452	3,346	28,474
Kentucky	28,265	15,764	2,548	94,292	\$764	27,596	1,581	1,101	2,005	22,909
Maryland	0	7	0	48	<\$1	15,998	161	0	804	15,033
New York	2,872	6,045	175	46,923	\$338	50,399	964	820	4,338	44,277
Ohio	29,039	33,828	5,785	90,301	\$860	48,954	4,660	2,134	4,969	37,191
Pennsylvania	16,061	43,906	3,670	163,300	\$1,295	60,698	3,853	5,097	7,798	43,950
Tennessee	510	350	350	1,000	\$21	31,659	526	624	1,093	29,416
Virginia	7	4,673	21	85,800	\$608	41,962	956	331	2,220	38,455
West Virginia	3,937	43,034	1,474	201,770	\$1,483	17,528	4,013	871	2,770	9,874
TOTALS	117,936	148,766	27,474	686,961	\$5,911	373,135	19,216	18,540	35,463	299,916

Economic benefits are substantial across the oil and natural gas value chain

More than 370,000 people are employed in the oil and natural gas industry in the Appalachian and Illinois basins states, from exploration and production through wholesaling and retailing.²³ Regional industries employing millions more workers rely on oil and natural gas for feedstocks or process heat – particularly primary manufacturing and materials industries that, in turn, have a profound impact on the U.S. economy as a whole.

Helping to Meet Peak Demand



Exploration & Production

Appalachian and Illinois basins account for more than 19,000 direct jobs in exploration and production.



Refining & Processing

About 18% of the nation's crude oil refining capacity exists in the Appalachian and Illinois basin states.²⁴



Transportation & Storage

An extensive network of pipelines and storage fields connects producers in the region with important markets. More than 40% of the nation's natural gas storage capacity exists in Appalachian and Illinois basin states.²⁵



Wholesale & Retail Distribution

A vast network distributes natural gas and petroleum products throughout the Appalachian and Illinois basins states, which constitute the most densely populated region of the country.



End Uses

Oil and natural gas produced in the Appalachian and Illinois basins find ready markets in the region as fuels and feedstocks in the commercial, industrial, residential, transportation, and agricultural sectors. Natural gas is also increasingly used to fuel power plants.

Consumption

Oil Consumption Percent of State Energy Use by Sector						Natural Gas Consumption Percent of State Energy Use by Sector						
Total	Resid.	Comm.	Ind.	Elec. Pwr	Transp.	Total	Resid.	Comm.	Ind.	Elec. Pwr	Transp.	
34%	2%	2%	28%	1%	98%	25%	47%	23%	24%	3%	1%	Illinois
30%	4%	3%	16%	<1%	99%	18%	30%	20%	20%	1%	1%	Indiana
37%	3%	3%	30%	<1%	97%	12%	17%	15%	12%	<1%	3%	Kentucky
40%	9%	5%	31%	7%	99%	13%	20%	17%	11%	4%	1%	Maryland
41%	20%	12%	31%	12%	96%	29%	33%	28%	13%	24%	1%	New York
33%	4%	2%	20%	<1%	98%	21%	36%	26%	21%	1%	2%	Ohio
37%	16%	6%	20%	2%	96%	17%	27%	20%	17%	1%	4%	Pennsylvania
32%	2%	2%	16%	1%	98%	12%	14%	15%	16%	<1%	2%	Tennessee
39%	9%	4%	20%	7%	99%	11%	13%	12%	13%	5%	1%	Virginia
28%	5%	3%	16%	<1%	82%	20%	23%	27%	17%	<1%	18%	West Virginia

Independents make vital energy contributions

The oil and gas industry is frequently characterized as Big Oil. Yet this image is misleading. Thousands of independent oil and gas producers – most employing fewer than 20 people – drill 85 percent of the nation's wells and produce 65 percent of the natural gas and nearly 40 percent of the oil produced in the United States. Recognizing the important contributions of these producers to our nation's domestic energy portfolio, the U.S. Department of Energy has technology transfer programs targeted specifically to small independents.

Small producers are single-handedly responsible for maintaining the operation of "stripper" wells in the United States, defined as a gas well that produces less than 60 thousand cubic feet (Mcf) of gas per day, or an oil well that produces less than 10 barrels (Bbl) of oil per day. In 2003 there were 260,563 stripper gas wells in the United States, producing a total of 1,478 Bcf, or enough to meet one month of U.S. natural gas demand. That same year, there were 393,463 stripper oil wells²⁶, producing a total of 313 MMBbl, which was 15 percent of total oil produced in the lower 48 states.



Small businesses are the backbone of the Appalachian and Illinois basins

Small independent oil and gas producers and service companies predominate in the Appalachian and Illinois basins. During the past 10 years, thousands of independent operators have been in business in the basin states²⁷, with the greatest numbers in Pennsylvania, Ohio, West Virginia, and Kentucky. Many operators are small family-owned businesses that are vital economically to their rural communities. Because these small businesses have limited capital, many find it difficult to invest in large or deep drilling projects, or to apply state-of-the-art technologies. Their next year's drilling schedule often is determined by this year's revenues, and is weighed against uncertain and volatile oil and natural gas prices.

Producing natural gas wells in the Appalachian and Illinois basins numbered 148,766, approximately 38 percent of the over 393,000 producing gas wells in the United States, according to the Energy Information Administration. Moreover, 117,936 of the nation's 520,000 producing oil wells (23 percent) are also in this region. Many of these wells are low-volume "stripper" wells. Cumulatively, stripper well oil and natural gas production is an important supply source for the Appalachian and Illinois basin states and for the country as a whole.



Beside his service rig truck, Carl D. Perkins of Pennsboro, West Virginia, stands with son Deryl and grandsons Clay and Clint. Carl Perkins is president of Perkins Oil & Gas, Inc., an independent producer.

Prerequisites for Bringing Resources to Market

Keys to reinvigorating production in the basins

Realizing more of the oil and natural gas resource potential of the Appalachian and Illinois basins will take action on several fronts. Investments in technology will be needed for maintaining production in marginal fields and for applying new technologies, like CO₂-based enhanced oil recovery, in mature fields in the Appalachian and Illinois basins.

In addition, supportive policies will be needed to provide appropriate access to resources, enable necessary infrastructure expansion, enhance access to high-quality information on resource potential, and ensure environmental stewardship. Each of these prerequisites is discussed on the following pages.

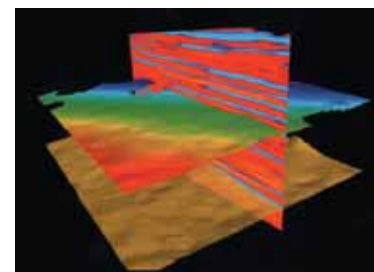
Prerequisite 1: Technology progress

Production of oil and natural gas in the Appalachian and Illinois basins was concentrated in the late 19th and early 20th centuries, in an era when technology options were limited. A host of recent technology advances have been underutilized in the basins to date, but could greatly enhance the region's oil and natural gas recovery potential. Increased development and application of advanced technology will be essential to meet the challenges of producing the unconventional and challenging resources that constitute most of the remaining potential in the basins.

Extending well life

Perhaps the most immediate target for advanced technologies is **extending the lives of marginally economical wells**. Production levels in many wells decline prematurely and unnaturally, often due to avoidable and repairable wellbore damage; higher oil and natural gas prices alone are

not enough to save wells – and entire fields – from premature abandonment. To assist the small and independent operators who own the vast majority of the nation's stripper wells, The Pennsylvania State University, with support from the U.S. Department of Energy and New York State Energy Research and Development Authority (NYSERDA), established the Stripper Well Consortium. Through the consortium, operators leverage their resources to analyze the causes of premature production decline and to develop effective remediation approaches. Such efforts can result in higher production volumes, longer well life, and, thus, greater cumulative production. An example of a developing technology suitable to the Appalachian and Illinois basins is a “gas operated automatic lift pump” that can reduce lifting costs and increase production.



This seismic image shows subsurface features including petroleum reserves. Use of 3D imaging increases the likelihood of success in targeting oil and gas resources.

Exploration

Other technologies will enable the economical development of new wells. For example, **improved fracture detection** will enable developers to better assess the producibility of natural gas from tight sands, coal seams, and shales. Exploration technology to verify the geometry of fractures, coupled with the creation of maximum fracture intersection through techniques such as horizontal drilling, will have a significant impact on the overall ability to produce gas economically from these formations. Research to improve natural fracture prediction for tight gas sands is currently being conducted in other tight gas basins with results that may benefit operators in the



The location of the drill site may vary based on geology, topography, surface access, and other factors, as illustrated by this high-elevation site in Virginia.

Appalachian and Illinois basins. Another development with potential applicability in the basins is taking place in the Fort Worth basin, where horizontal wells are being used successfully to intersect open fractures in the Barnett Shale. Although horizontal wells have been drilled in the past, success in the Barnett may stimulate renewed interest in drilling horizontal wells in gas shales in the Appalachian and Illinois basins.

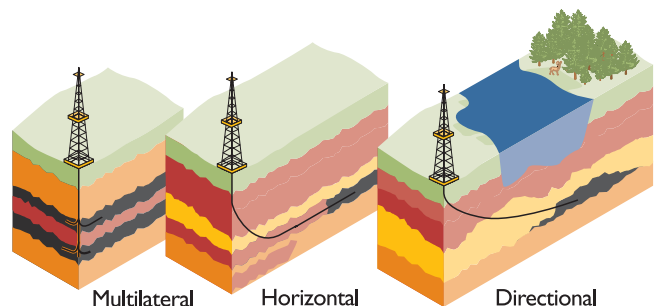
Another exploration technology that can be beneficially applied in the basins is **advanced 3D seismic imaging**. Widely used in oil and gas fields throughout the world, 3D seismic imaging provides developers with detailed information about fault distribution and subsurface structures. Increasingly, operators in the Appalachian and Illinois basins are finding economic justification for purchasing 3D seismic data to refine their stratigraphic objective in complex reservoirs, including deep targets and reef plays. Further advances in processing, seismic modeling, and attribute analyses will help better identify current and new targets for exploration in the Appalachian and Illinois basins.

Drilling and completion

Advances in **drilling and completion** technologies clearly will be important in decreasing future well costs and making more resources economically producible. “Tight gas sand” stimulation techniques may be particularly applicable within the Appalachian basin, enabling operators to improve gas production rates. Other key advances are horizontal and lateral sidetracks. Horizontal and lateral drilling has already proved valuable in the region – for example, by enabling operators to drill successfully in the Trenton/Black River reservoirs in New York. Drilling and completion techniques also are needed to address the challenges of unexplored deep reservoirs in the basins. Technologies currently under development by DOE’s Deep Trek program include high-temperature electronics for wireline tools applied under conditions greater than 15,000 feet and 400 degrees Fahrenheit, and deep sand completion techniques. These advancements could one day help make exploration and production of deep gas reservoirs in the Appalachian basin economically feasible.

Production

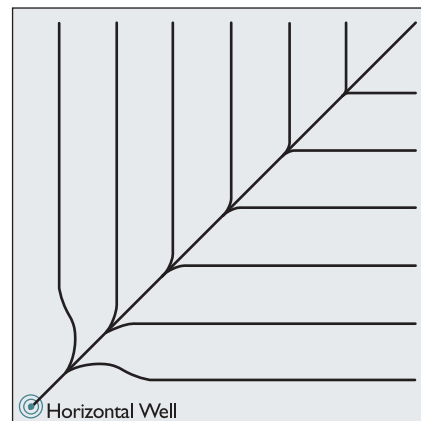
Technologies specific to **coalbed natural gas production** are being applied increasingly in basins across the United States, and hold promise for enhancing production from the Appalachian and Illinois basins. Examples include advances in multi-seam drilling and completion of thin or low-permeability coals, retreatment of existing wells, and efficient drilling and completion of lower-gas-content



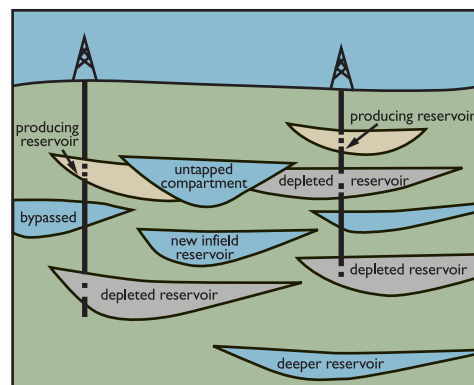
Multilateral, horizontal, and directional drilling technologies enable more resources to be recovered with less waste and surface disturbance.

coals. One technology that has been applied successfully in southern West Virginia is the CDX Z-PINNATE™ drilling and completion system. This technique uses a multilateral horizontal network (resembling the shape of a leaf) that can drain 1,200 acres of coal with one well, far exceeding the 80- to 100-acre capability of existing technologies.

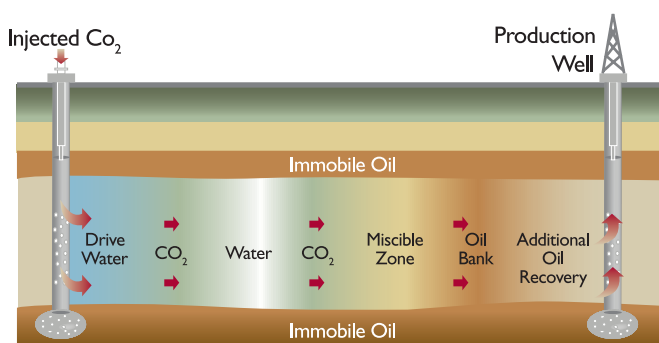
Potentially “stranded” natural gas and oil resources in depleted fields in the basins can be pursued with advances in **enhanced recovery techniques**. Anywhere from 50 to 70 percent of oil and 20 to 30 percent of natural gas is not recovered with traditional approaches. Broader use of enhanced recovery technologies (CO₂ flooding, steam flooding, or water flooding) with 4D seismic imaging and automated field monitoring may enable recovery of more of the original oil-in-place after primary production is completed in oil fields. According to the *Oil and Gas Journal*, CO₂ flooding is the fastest growing form of enhanced oil recovery in the United States, producing an estimated 206,000 barrels per day in 2004²⁸, mostly in the Permian basin of West Texas and New Mexico. To date, this technique has seldom been attempted in the Appalachian and Illinois basins. However, experience in the Permian basin and the Weyburn field in Saskatchewan, Canada, could provide a model, helping to overcome the risks and economic barriers associated with applying this technology to recover stranded oil in other basins, such as the Illinois and Appalachian basins. Other ways to encourage use of this technology to recover stranded oil in the basins include conducting research, pilot tests, and field demonstrations; providing risk-mitigating packages, such as state production tax incentives, federal investment tax credits, and royalty relief; and establishing low-cost, reliable CO₂ supplies from natural and industrial sources. In the near term, sources could include high-concentration CO₂ emissions from refinery hydrogen plants and gas processing facilities. Capture of lower-concentration emissions from sources such as electric power generation plants could be feasible in the longer term. Capturing CO₂ emissions for use in enhanced oil recovery also could have synergy with state, regional, and nation objectives to reduce atmospheric concentrations of greenhouse gases.²⁹



Z-PINNATE™ System Pattern
One example of a horizontal drilling pattern applied in coalbed natural gas production is the CDX Z-PINNATE™ drilling and completion system, which allows operators to produce more gas with fewer wells, in turn reducing stresses on the environment.



Much of the underdeveloped hydrocarbon resource in the Appalachian and Illinois basins exists in reservoirs that were difficult to find and access with traditional technologies. With advanced technologies such as 3D seismic and horizontal/directional drilling, these prospects can now be pursued.



A recent study found that 43 billion barrels of stranded oil could be recovered using available state-of-the-art carbon dioxide-enhanced oil recovery (CO₂-EOR) techniques in six U.S. basins. Of that, nearly one billion barrels are located within 46 reservoirs in Illinois.³⁰

Unique state actions in Virginia to increase energy supplies

A bill passed overwhelmingly by the Virginia state legislature in 2005 directed state officials to ask Virginia's congressional delegation to advocate an exemption to the federal moratorium on offshore natural gas exploration. Virginia would have become the first state to formally seek an exemption from the federal moratorium Congress enacted in 1982 that prohibits offshore drilling on the Atlantic and Pacific coasts and part of the Gulf of Mexico. This bill, however, was later vetoed by the governor in part because it directed the state to advocate for federal legislation that had not yet been introduced. Legislation subsequently introduced in the 109th Congress would give coastal state governors the power to open some or all of their states' offshore lands restricted by federal moratoria, with an emphasis on "gas-only" leasing.

On another front, Virginia succeeded in encouraging coalbed gas production through legislative action. Decades of mining in the southwest Virginia coalfields had demonstrated the gassy nature of coals in the area. Development of the gas as a separate product, however, had been stymied by split mineral estates: coal owners and oil and gas owners, each of whom claimed ownership of the coalbed gas, were often separate entities. To address the ownership dilemma, the Virginia legislature passed landmark legislation in 1990 that provided for compulsory pooling of unleased parties and the escrow of proceeds due to conflicting claimants to coalbed gas. This action allowed development to go forward while protecting the interests of claimants until ownership could be determined through court order or agreement. As a result of the legislation, gas production in Virginia's seven-county producing area has increased more than 400 percent and continues to rise. Coalbed gas currently makes up nearly 80 percent of Virginia's total yearly gas production.

Technology transfer

Across the board – from exploration, to drilling and completion, to production – advanced technologies can make all the difference in enabling increased energy supplies from the Appalachian and Illinois basins. Unfortunately, the application of advanced technologies in this region is not yet widespread, and smaller independent producers, who account for the majority of oil and natural gas production in the basin states, often lack the access to capital and expertise required to integrate advanced technologies into their operations. Substantially greater efforts are required to further demonstrate the potential applicability of advanced technologies to independent producers in the Appalachian and Illinois basins. This would build upon efforts currently ongoing, primarily conducted by the IOGCC and the Petroleum Technology Transfer Council, an industry-driven, nationwide organization. West Virginia University serves as the regional lead organization for the Appalachian region, and the Illinois State Geological Survey is the regional lead organization in the Illinois and Michigan basins.

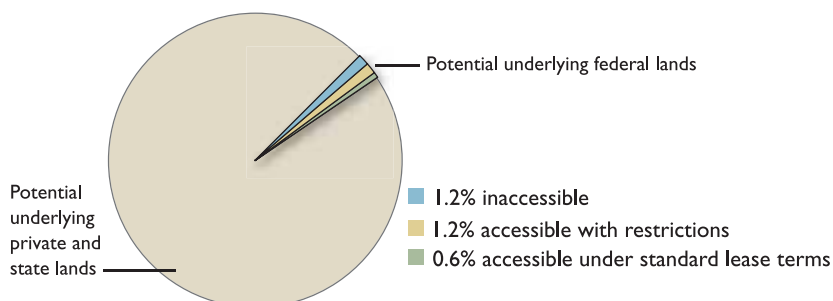
Prerequisite 2: Access to resources

Obtaining access to oil and natural gas resources can be complex, involving the interests of private land and royalty owners, ambiguous mineral rights, and competing land uses. Unlike in the western United States, where a significant portion of undeveloped resources underlie public (primarily federal) lands and are either unavailable for leasing or subject to additional leasing restrictions, most of the resource base in the Appalachian and Illinois basins is held by rights with private entities. Nevertheless, much of the area with future potential still faces access issues.

Federal lands

About five percent of total acreage in the Appalachian basin (more than five million acres) is on federal lands or on split-estate lands where the federal government owns mineral rights while another entity owns the surface land. Federal lands in the basin are managed primarily by the U.S. Forest Service. Only about three percent of the undiscovered resource

Very little of the undiscovered oil and natural gas resources in the Appalachian basin are on federal lands.



potential in the basin is estimated to underlie these federal lands. Most of this resource potential is accessible under standard lease terms or with restrictions, which are related primarily to controlling surface use for wildlife habitat and riparian ecosystem protection and limiting operations on steep slopes for erosion control. The primary endangered species of concern in the basin is the Indiana bat. Protecting this species can require limited operations for certain periods (generally the bat's breeding season) in some areas.³¹ An interagency study mandated by Congress in the Energy Policy and Conservation Act Reauthorization of 2000 is under way to characterize any impediments to development of oil and natural gas underlying onshore federal lands. Results related to the Appalachian basin are anticipated in 2005.

State lands

State and local governments in the region control significant amounts of land for parks, recreation, reforestation, and other uses. Access to state-owned lands is subject to site-specific requirements. Some lands, such as state parks, have legal or constitutional use restrictions. On other lands, multiple uses, including oil and gas development, may be allowed depending on specific circumstances.

Even on lands available for oil and gas development, some members of the public may perceive such development to be an intrusion that would interfere with other uses, such as recreation, and may feel a sense of personal ownership of these lands. For these reasons, oil and gas development on state and local government lands can be subject to heightened restrictions to protect environmentally and publicly sensitive areas, such as endangered wildlife habitat, steep slopes, riparian ecosystems, and trails and other recreation areas.

Several Appalachian and Illinois basins states border on the Great Lakes. Thirteen wells have been drilled directionally from the Michigan coastline of Lake Michigan and Lake Huron, and more than 2,000 wells have been drilled under Lake Erie from Canada. However, in response to

public opposition, Michigan suspended such drilling, and a Congressional moratorium was established through 2007 on drilling in the Great Lakes. In 2005, Congress legislated a permanent ban.

Coal resource interface

Competing **mineral rights** also can complicate access to resources in the basins. Many areas with potential for natural gas production – including coalbed gas – had historically been leased for coal mining. Many lease agreements date to the late 1800s, under terms that might be interpreted as ambiguous. Today, if an oil and gas operator wants to drill for gas in an area previously leased to a coal operator, a legal dispute frequently arises over who owns the rights to the gas within the coalbeds.³² Legal precedent must be established in each state to decide the issue, and even then, unique circumstances can lead to prolonged legal entanglements. This problem has loomed large over prospective coalbed natural gas operators and has stopped production of this resource in some areas. Several states have passed legislation allowing development of the resource while ownership issues are settled. In states passing such legislation, an increase in production often quickly results.



In the Appalachian and Illinois basins, more than 10 million acres are managed by state governments. Leasing for oil and gas development on state lands is not new to the basins. For example, it has existed since the 1940s in Pennsylvania and since the 1930s in New York. Drilling and operation plans are adjusted to protect the environment and public safety and to reflect surface-management goals for each location.

Suburban growth

Another factor affecting access to oil and natural gas resources is urbanization. While much of the Appalachian and Illinois basins region was rural in the early days of development, energy production now must be balanced with competing urban and suburban land uses. For example, as part of House Bill 278, Ohio enacted a statutory amendment in 2004 for special well permitting to address conflicts that can arise between population centers and oil and natural gas producers. The amendment places regulatory authority in suburban areas with the state oil and gas agency, eliminating duplicative regulatory layers caused by a myriad of local ordinances. The legislature also enacted safety, environmental, and aesthetic requirements to address the unique circumstances caused by high populations in proximity to oil and gas wells.

Valuable resources available to Ohio communities include a first-of-its-kind, comprehensive training manual, *Responding to Oilfield Emergencies*, along with a facility to train local emergency responders on effective practices for oil field sites. These resources were developed by the Ohio Oil and Gas Energy Education Program (OOGEEP). In addition, the Ohio Department of Natural Resources Division of Mineral Resources Management provides a web site designed to improve response times to oil and gas well emergencies, facilitate compliance with spill-reporting requirements, and provide more efficient and accessible community-right-to-know reporting. The web site, developed by Argonne National Laboratory with funding from DOE, serves as a model for other states with oil and gas production operations.



This fenced-in well (foreground) illustrates how unobtrusive production operations can be in suburban locations.

Along with OOGEEP, other educational programs in the region are working to increase public awareness of the oil and natural gas industry and to promote safe, productive, and environmentally sound operating practices. The Illinois legislature established an energy education program in 1999, and the Independent Oil and Gas Association of New York is currently seeking to create such a program. Several states participate in the National Energy Education Development (NEED) project, and, through a U.S. EPA grant, the IOGCC's Energy Education Partnership and the West Virginia Department of Environmental Protection have conducted workshops for school teachers on coalbed natural gas.

Prerequisite 3: Infrastructure expansion

Operators in the Appalachian and Illinois basins are often not far from an interstate gas transmission line to one of the major gas hubs. In fact, a significant portion of the nation's natural gas supplies flows through the Appalachian and Illinois basins. This proximity is a competitive advantage because the operators do not have to deal with price discounts experienced by producers further from the market, such as those in the Rocky Mountain West. For example, an operator in West Virginia can sell gas at the Dominion Hub and incur minor transportation costs, realizing a greater "well-head net back" than an operator in Wyoming selling at the Cheyenne Hub.

However, not all of the resource potential in the basins currently has access to the existing infrastructure, either because the resource exists far from a pipeline or storage access point or, more often, because nearby pipelines and storage fields are already operating at or near full capacity. As new production from these basins comes on line, shortages of transportation capacity can become significant barriers to further development.

Underground storage will play an increasingly prominent role in balancing supply and demand, in both the short term (based on weather) and the longer term (in response to changing structural

supply/demand changes). Gas storage capabilities must expand and become more flexible as natural gas increasingly serves the power generation and home heating markets in the Northeast in addition to its traditional industrial consumers.

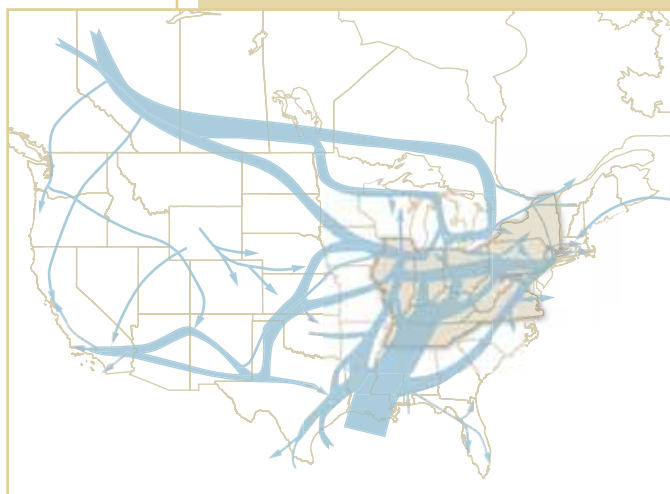
The effective development of resources in the Appalachian and Illinois basins is confronted with a “chicken-and-egg” dilemma. New production needs access to a pipeline to be profitable, and new pipeline capacity needs production to be viable. The fundamental question is who assumes the initial risk. For example, much of the natural gas development under way in eastern and southeastern Kentucky is currently constrained because of inadequate capacity. To address this type of dilemma, the state of Kentucky recently passed legislation establishing the Kentucky Gas Pipeline Authority, which is authorized to provide financing mechanisms – including issuing revenue bonds – to facilitate the implementation of natural gas and coalbed natural gas projects related to storage, gathering, and transportation.³³

Increasing pipeline access to new supplies in the Appalachian and Illinois basins may be constrained by public opposition and the sometimes lengthy and burdensome process by which government and industry attempt to resolve land use and environmental concerns. For example, state concerns were raised as part of consistency review under the Coastal Zone Management Act that prevented the Millennium pipeline project, which was intended to transport natural gas from western New York State to New York City, from being approved. Concerns at the state level also substantially delayed the Islander East pipeline project originating in Connecticut and crossing into New York.

Additional gas gathering compression and processing also may be required to bring new supplies from the Appalachian and Illinois basins.³⁴ The quality of most gas produced in the basins allows it to be input into the existing pipeline system with minimum preparation (generally, simply the removal of water). However, gas produced in the future may be of lower quality, requiring additional processing to meet pipeline specifications. One concern to producers is how “gas gathering” operations may be regulated in the future. Federal pipeline safety law³⁵ requires that the Department of Transportation (DOT) define the term “gathering line” to develop an inventory of those lines and to identify a class of regulated gathering lines that warrant some safety regulation. At issue for producers is establishing a clear point where production ends and gathering begins, a regulatory distinction that in the past has been, at best, ambiguous. Some industry trade groups are urging DOT to adopt American Petroleum Institute Recommended Practice 80 – an industry consensus standard defining both “production facility” and “gathering lines.” Establishing regulatory stability related to pipeline construction and operation is an important goal for the regulated community, particularly for the Appalachian oil and gas industry.

Proximity to markets

A significant portion of the nation's natural gas supplies flows through the Appalachian and Illinois basins. While the existing infrastructure for transportation and storage in the region is extensive, some expansion will be necessary to ensure that new production from the basins can be effectively brought to the market.



The high-deliverability Stagecoach facility is the easternmost underground natural gas storage facility in the United States. This facility was recently sold by Central New York Oil and Gas Company to Inergy L.P. The facility has a maximum withdrawal capacity of 500 MMcf/day to meet the peak gas needs of the eastern United States.

Prerequisite 4: Access to high-quality data

Access to high-quality data about the extent, maturity, and diversity of oil and natural gas resources and about production histories of existing fields is invaluable to potential developers and other stakeholders. Good data enable the identification of new prospects, increase the likelihood of successful exploration and production, and assist state agencies in monitoring the progress of development and ensuring use of appropriate environment safeguards.

Data accessibility

Currently, the accessibility of resource and production data related to the Appalachian and Illinois basins varies from state to state, with limited consistency in scope or quality. With regard to coalbed natural gas, available data are sparse for areas outside known productive regions. Only a handful of older gas-content

analyses are available for all of Ohio and eastern Kentucky, for example. Of the more than 30 potential coalbeds in the region, relatively few have been tested in any one area. Several research efforts are under way in the Illinois basin to obtain additional gas content analyses and other reservoir characterization data. Similar regional characterization work, including water analyses, is needed in the Appalachian basin in order to more fully evaluate the potential for production as well as to establish the proper regulatory framework for managing development.

Improved data on deeper geological formations also will be important in the Appalachian and Illinois basins. Most production in the basins to date has come from relatively shallow depths, and deeper formations have been little explored. Developing a better geological characterization of these deeper horizons is critical to assist in the exploration for additional oil and gas reserves. State geological surveys, in cooperation with industry, play a critical role in developing and disseminating such data.

Highlights of innovation in state agency data management

Illinois	While more than 3.2 billion barrels of oil have been produced, increased production of remaining oil resources will depend on access to large amounts of data and effective data evaluation and management. The Illinois Oil and Gas (IL OIL) project, funded by DOE, was designed to alleviate data access constraints by developing techniques for evaluating underdeveloped areas in and around petroleum reservoirs in Illinois. The Illinois State Geological Survey statewide database was used to develop a series of interactive maps with well locations color-coded by producing horizon. The maps can be presented either as a single-pay horizon or layered to show multiple horizons. A second series of maps that identify underdeveloped areas has been created from a waterflood database. ³⁶
Indiana	The Indiana Geological Survey's Petroleum Database Management System (PDMS) is an online tool used to manage and process information related to petroleum test wells. The database contains information on more than 70,000 petroleum-related wells drilled in Indiana, including well locations, completion zones, logs, operators, lease names, tests, hydrocarbon shows, samples, cores, geologic formations and tops, and much more. The PDMS is used to generate maps that show petroleum wells, oil and gas fields, production, and other data in standardized and custom formats.
Kentucky	The Kentucky Division of Oil and Gas has developed a comprehensive database documenting more than 110,000 wells. The Division uses handheld computers in the field to record facility inspection data. GIS and GPS capabilities enable field inspectors to collect or verify the accuracy of well location data. Public access to oil and gas well data is through the web-based system implemented by the Kentucky Geological Survey. The system includes access by user query, an interactive map interface, scanned images of geophysical logs and well records, and data that can be downloaded for use in mapping software. Kentucky is a national leader in digital geologic mapping, having digitized 707 1:24,000-scale surface geologic maps compiled by a cooperative mapping project with the U.S. Geological Survey between 1960 and 1980.
Ohio	The Ohio Division of Mineral Resources Management led national efforts to develop the Risk-Based Data Management System and forged the way for other states to make the transition from paper to electronic repositories. Innovations include Ohio's Emergency Response Oil and Gas Well Locator web site, which allows emergency response personnel to locate wells and provides contact information and locations of nearby schools, hospitals, roads, and bodies of water. The emergency web site is used by the Ohio oil and gas industry to electronically submit SARA Title 3 community right-to-know information, eliminating the requirement for multiple copies of paper reports and providing first responders immediate electronic access to stored chemical information in an emergency situation.

States are continuously working to improve access to information about oil and natural gas resources, production, and operations in the basins. For example, the Illinois State Geological Survey and the Midwest Petroleum Technology Transfer Council recently introduced a service that allows online searches of historical well data in map form. Other efforts include studies by state geological surveys on emerging plays, such as the Trenton/Black River, New Albany Shale, and coalbed natural gas.

Risk-based data management

For many years, the Ground Water Protection Council, a national association of state ground water and underground injection control agencies, has worked to develop better ways to protect and conserve ground water resources. One of the major products of this effort has been the risk-based data management system (RBDMS), a mature electronic data management system underwritten by DOE funding, which is now being used in 21 states including Kentucky, Ohio,

Pennsylvania, and New York, to manage their oil and gas information and to make better regulatory and resource management decisions. Developed originally as a way to manage the data needed to protect underground sources of drinking water, RBDMS has evolved to include oil and gas production and permitting data, wellbore schematics, geographic information system capability, Internet access, and electronic permitting and reporting. Attributes of RBDMS include its use of nonproprietary software, its capability to address legacy databases, and its adaptation to variations in state oil and gas regulatory and production accounting methods.

RBDMS enables increased environmental protection by allowing rapid access to data needed by regulatory agencies to assess environmental risk of oil and gas operations. It significantly reduces costs for industry compliance and increases government efficiency. Future priorities include continuing the development and implementation of national e-commerce solutions for oil and gas regulatory agencies and industry.

Pennsylvania	The Wells Information System (WIS) is a comprehensive database created by the Pennsylvania Geological Survey that stores details associated with drilled oil and gas wells, as well as undrilled, canceled, void, or expired drilling permits. This relational database allows for the entry, storage, access, and analysis of data through linked data fields. Survey staff members augment the database daily, based on data reported by oil and gas companies. A geographic information system linked to WIS can be used to create "oil and gas base maps" showing the locations of wells and other important geographical information. ³⁷
West Virginia	West Virginia has developed an atlas of major Appalachian gas plays, a 200-page compendium containing maps and descriptions of key gas fields in each of 30 gas plays in the Appalachian region. A companion database includes information on more than 5,100 individual gas reservoirs. Both the atlas and database were developed by the Appalachian Oil and Natural Gas Research Consortium at the West Virginia University. The consortium conducts multidisciplinary research on petroleum and natural gas technology, in partnership with five state geological surveys (West Virginia, Ohio, Pennsylvania, New York, and Kentucky). New analytical approaches have led to more accurate calculations of the nation's known and potential gas resources, including unconventional resources such as low-permeability "tight" gas reservoirs, gas shales, and coalbed natural gas.
New York	The New York Division of Mineral Resources has developed a comprehensive RBDMS database that includes regulatory and status information on more than 35,000 wells, annual well reporting, and state land oil and gas leasing revenue and status tracking. Other enhancements include an electronic production reporting system that accounted for more than 94 percent of gas production last year and a PDA field inspection system. DOE funding through the Ground Water Protection Council made the database development possible. The database is linked to geographic information systems and the division's web site and is also shared with the New York State Museum's Empire State Oil and Gas Information System (ESOGIS), which provides enhanced Internet access to well data, including well completion reports and logs.

Smart energy/environmental solutions

Numerous policy and regulatory issues affect oil and natural gas supply and delivery in the basins. Efforts have been under way in state and federal agencies to achieve regulatory efficiency and establish more cost-effective, risk-based regulations based on sound scientific and technical information.

Regulatory jurisdiction over hydraulic fracturing. Hydraulic fracturing is used on thousands of wells every year to improve their productivity. Use of this long-established technique was threatened by litigation that would require unnecessary or duplicative regulation, adding to exploration and production costs. In response to public concerns and this legal challenge, a study by EPA concluded that hydraulic fracturing in coalbeds poses little or no threat to groundwater.³⁸ In 2005, Congress affirmed that hydraulic fracturing is not “underground injection” for the purposes of Safe Drinking Water Act regulation.

Storm water construction permitting. In 2003 EPA issued regulations for smaller municipal storm sewer systems and construction sites that disturb from one to five acres. Most onshore oil and gas well sites disturb from one to five acres and therefore could have been subject to these requirements. Although exploration and production facilities were exempted from the requirements, EPA interpreted this to not apply to construction that precedes exploration and production operations, such as road building and well site construction. Industry and states challenged this interpretation in court, and EPA deferred implementation of the regulations until 2006 pending further review of the exemption and the large potential costs and energy impacts. Existing industry and government standards, in some cases established for other purposes such as site preparation and erosion control for stabilizing drilling equipment, address the management of storm water discharges at oil and gas sites and reduce the potential for adverse impacts on water quality. In 2005, Congress extended the exemption to include oil and gas construction sites.

Spill prevention, control, and countermeasure (SPCC) plans.

Exploration and production facilities are currently required to prepare SPCC plans. However, in July 2002 EPA issued regulations that would impose potentially burdensome new requirements on these facilities. EPA has extended compliance dates to reconsider elements of the rules and to attempt to address potential economic implications.³⁹

Orphaned wells. Most states in the region have existing programs to address the problem of orphaned wells (wells with no known operator). Most require operators to post a bond that covers well plugging and site restoration in cases where the operators do not perform their regulatory obligations. Orphaned wells for which no bond has been established may be remediated using state plugging funds, which are generally derived from well permitting surcharges. State/Industry partnerships have successfully rehabilitated wells that would otherwise have been permanently abandoned and have properly plugged numerous unproductive wells in a cost-effective manner.⁴⁰ In 2005, Congress authorized new initiatives for addressing orphaned wells on federal, state and private lands in ways that aim to be practical, economic and protective of the environment.

Prerequisite 5: Environmental stewardship

Ensuring adequate supplies of energy to support economic growth and to meet consumer demand must be accomplished while protecting the environment. Industry, government, and the public all have roles in environmental stewardship.

The Appalachian and Illinois basins span ten states with strong and mature regulatory programs that effectively strike a balance between the orderly development of energy resources and environmental protection and public safety. Policies and procedures have been established that are responsive to the needs of citizens and the environment as well as the needs of permit applicants. With relatively small areas of federal lands in the basins, permit applicants deal primarily with state permitting authorities that have the ability to respond to permit applications thoroughly and rapidly. Since many wells in the basins are stripper wells – with economic viability that can be jeopardized by increased costs – efficient and responsive regulatory programs are the norm in the region.

At the federal level, the states in these basins are subject to regulation by four different Environmental Protection Agency (EPA) regional offices (regions 2, 3, 4, and 5). While there are many similarities in the content and administration of state-mandated programs, differences sometimes arise between federal and state regulatory requirements. Some states in the basins implement federal regulatory programs directly by acquiring federal approval through a process known as primacy, while other states opt to have EPA implement directly.

The continuation of a balanced regulatory approach – one that ensures environmental protection while developing oil and gas supplies – is critical for energy production to remain viable and grow in the Appalachian and Illinois basins.

State agencies continually strive to achieve statutory objectives while emphasizing customer service to public and industry citizens, landowners, and small businesses (such as independent oil and gas operators, who benefit from program efficiencies in the region). The Appalachian and Illinois basins programs meet regularly to compare policies, procedures, and technologies, in order to increase consistency and effectiveness across the region.

Such efforts are facilitated by STRONGER, or the State Review of Oil and Natural Gas Environmental Regulations. STRONGER was formed in 1999 to carry forward the state review process begun cooperatively in 1988 by EPA and the IOGCC. STRONGER is a nonprofit, multi-stakeholder organization whose purpose is to educate and provide services for the continuous improvement of regulatory programs and industry practices in order to enhance human health and the environment. The state review process – in recent years funded by EPA, DOE, and the American Petroleum Institute – is not mandatory and relies on states to volunteer for reviews. Since 2001, reviews have been conducted in Indiana, Ohio, Pennsylvania, Virginia, and West Virginia. New York and Kentucky are scheduled for their second, or follow-up, review in 2006.

Despite the strong and mature programs in the region, ongoing program maintenance is needed to keep up with changing technologies and customer needs. Continued vigilance assures that proper levels of financial and public policy support is provided by governments to maximize safe, effective, and orderly development of energy resources in the region. In particular, as industry recognizes the potential of these basins, exploration and development activity is likely to increase, and the personnel and resources required to facilitate appropriate oversight must change accordingly. In response to this concern, the Petroleum Technology Transfer Council has held several training sessions for well tenders in the Appalachian and Illinois basins in the past two years.



Next Steps

Encouraging resource development and economic growth through basin-wide strategies

Key decision makers affecting oil and natural gas supply and delivery in the Appalachian and Illinois basins

State oil and gas regulatory agencies

State geologic surveys

State departments of natural resources and environmental quality

State lands commissions

State fish and game commissions

State historic preservation offices

State and regional economic development agencies

State public utility commissions

State legislators

Municipalities

State universities

Research and technology transfer organizations

Federal agencies

- Environmental Protection Agency

- Department of Energy

- Department of Agriculture

- U.S. Forest Service

- Department of the Interior

- Bureau of Land Management and Fish and Wildlife Service

- Department of the Treasury

- Department of Transportation

- Federal Energy Regulatory Commission

Private landowners

Consumers

Private citizens

Public interest groups

Financial community

Individual companies and trade associations

Oil and natural gas production from the Appalachian and Illinois basins already makes a far-reaching contribution to the regional economy – generating jobs, tax revenues, and benefits to businesses and consumers. Prospects for boosting these contributions through increased resource recovery are promising. The Appalachian and Illinois basins remain rich in hydrocarbon resource potential that, increasingly, can be produced economically with advanced exploration and production technologies.

Realizing this potential will take action by a range of private and public stakeholders to address five prerequisites:

- **Technology progress.** Advanced technologies must be developed and applied to extend the lives of wells and to economically find and produce resources in challenging settings.
- **Access to resources.** Supportive policies are needed to provide access to resources on public lands in an environmentally sound manner, to resolve mineral rights conflicts, and to address unique access issues in urbanized areas.
- **Infrastructure expansion.** Expansion of natural gas pipelines, gathering systems, and storage will be required to bring new production in the basins to market.
- **Access to high-quality data.** Potential investors in the region will require access to large amounts of data on resources and production, coupled with effective data analysis and management.
- **Environmental stewardship.** Strong and responsive regulatory programs, incorporating cost-effective regulatory strategies, are essential to balance energy production and environmental protection.

Collaborative approaches and basin-wide perspectives will be fundamental in tackling these prerequisites and accelerating recovery of natural gas and oil from the Appalachian and Illinois basins. Diverse stakeholders have an interest in the responsible recovery of these resources (see sidebar), not only to meet domestic energy needs, but also to stimulate economic growth in the region. Several public-private efforts – such as the Appalachian Oil and Gas Research Consortium – are already under way to encourage productive dialogue among these stakeholders. In addition, officials from the Appalachian and Illinois basins states meet regularly to share information and best practices for resource conservation and responsible development.

Other collaborative strategies may be valuable in leveraging technology to its fullest potential in the region. For example:

- Public-private partnerships might be pursued to focus on the development and application of advanced oil and natural gas supply technology.
- State geologic surveys should be granted additional funding to provide more and better information on the characteristics of the potential hydrocarbon resources remaining in these basins.
- Providing financial incentives for unconventional gas and enhanced oil recovery technologies is another possible strategy to stimulate their application in new areas.

Some opportunities would require concerted efforts by multiple industries and government entities. One example would be a regional effort to capture industrial carbon dioxide for use in CO₂-enhanced oil recovery, thereby increasing oil production in the region and reducing atmospheric carbon emissions. Likewise, providing the necessary new gathering, transportation, and

storage infrastructure to move increased natural gas supplies to market may call for joint ventures or similar risk-sharing relationships between producers and pipelines.

Clearly, effective basin-wide strategies must be based on input from the diverse group of stakeholders involved. As an initial step, the IOGCC's Appalachian and Illinois Basin Directors could begin conducting a series of stakeholder workshops designed to develop such basin-wide strategies. Recommendations coming out of this process on actions required to carry out the strategies could then be forwarded to state and federal policy makers, along with the key participants from industry.

Implementing basin-wide strategies to effectively pursue the large remaining hydrocarbon resource base in this region will be challenging. Yet the prospective returns to our nation – and to the Appalachian and Illinois basins states – justify concerted efforts. Our nation's energy security and economic growth can be enhanced by tapping the youthful potential of these mature basins.



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- Market values for oil and gas production were determined by multiplying oil and gas production, respectively, by a basin average (weighted average by state) first-purchase price of \$38.32 per barrel for crude oil and \$7.08 per Mcf wellhead natural gas price, based on state-specific prices as reported by EIA for 2004.
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All web site citations as of August 2005

Appendix: Informational Resources

Key links

Interstate Oil and Gas Compact Commission
www.iogcc.oklaosf.state.ok.us

The U.S. Department of Energy's Office of Fossil Energy pursues the DOE mission to foster a secure and reliable energy system that is environmentally friendly and economically sustainable. DOE conducts research on advanced energy technologies and provides scientific, technical, and other information to inform industry and government decision making.
www.fossil.energy.gov

The National Energy Technology Laboratory Strategic Center for Natural Gas & Oil implements DOE's Office of Fossil Energy Natural Gas and Oil research and development programs. www.netl.doe.gov/scngo/
The Independent Petroleum Association of America represents thousands of independent oil and natural gas producers and service companies across the U.S.
www.ipaa.org

State oil and gas agencies foster the responsible development of oil and natural gas resources in a manner that is protective of human health and the environment. For the Appalachian and Illinois basins, they are:

- Illinois Dept. of Natural Resources, Division of Oil and Gas www.dnr.state.il.us/mines/
- Indiana Dept. of Natural Resources, Division of Oil and Gas www.in.gov/dnroil/
- Kentucky Office of Mine Safety and Licensing, Division of Oil and Gas www.dmm.ky.gov/oandg/
- Maryland Dept. of Natural Resources www.dnr.state.md.us/
- New York State Dept. of Environmental Conservation, Division of Mineral Resources www.dec.state.ny.us/website/dmn/
- Ohio Dept. of Natural Resources, Mineral Resources Management www.dnr.state.oh.us/mineral/index.html
- Pennsylvania Dept. of Environmental Protection, Bureau of Oil and Gas Management www.dep.state.pa.us/dep/deputate/minres/oilgas/oilgas.htm
- Tennessee Division of Geology, Oil, and Gas Section www.state.tn.us/environment/permits/oil&gas
- Virginia Dept. of Mines, Minerals, and Energy, Division of Gas and Oil www.dmme.virginia.gov/dgo
- West Virginia Dept. of Environmental Protection, Office of Oil and Gas www.wvdep.org

State geological surveys provide science-based information on each state's geology and mineral and water resources to citizens, researchers, industry, and government. Some state geological surveys have regulatory responsibilities for water, oil and gas, land reclamation, and other issues. Surveys for states in the Appalachian and Illinois basins can be found online:

- Illinois www.isgs.uiuc.edu
- Indiana <http://igs.indiana.edu>
- Kentucky www.uky.edu/KGS
- Maryland www.mgs.md.gov
- New York State www.nysm.nysed.gov/esogis
- Ohio www.ohiodnr.com/geosurvey
- Pennsylvania www.dcnr.state.pa.us/topogeo
- Tennessee www.state.tn.us/environment
- Virginia www.dmme.virginia.gov/dmr
- West Virginia www.wvgs.wvnet.edu

Related links

The Petroleum Technology Transfer Council assists U.S. independent oil and gas producers in making timely, informed technology decisions by identifying and clarifying producers' needs, educating producers about technology options, and connecting producers to solutions. www.pttc.org

The industry-driven Stripper Well Consortium develops, demonstrates, and deploys new technologies needed to improve the production of oil and natural gas stripper wells. www.energy.psu.edu/swc/

The Gas Storage Technology Consortium assists in the development, demonstration, and commercialization of technologies to improve the underground storage of natural gas/hydrocarbons. www.energy.psu.edu/gstc/

The Ohio Oil and Gas Energy Education Program encourages oil and gas curricula in the classroom and promotes public awareness about the industry. www.oogeep.org. A similar organization in Illinois can be accessed at www.iprb.org.

The National Energy Education Development (NEED) project promotes an energy-conscious and educated society by engaging students and educators, along with business, government, and community leaders, to design and deliver objective, multisided energy educational programs. www.need.org



Oil and natural gas produced in the Appalachian and Illinois basins help to meet the rising energy demands of industries and other consumers. Technology progress is one key to tapping important new energy resources in this region.



Interstate Oil and Gas Compact Commission
Oklahoma City, Oklahoma
www.iogcc.state.ok.us



U.S. Department of Energy
Office of Fossil Energy
Washington, D.C. 20585
www.fossil.energy.gov



National Energy Technology Laboratory
Strategic Center for Natural Gas and Oil
www.netl.doe.gov

Design and editorial support: Akoya

Select photos courtesy of: Brandon C. Nuttall, Kentucky Geological Survey; Bruce Wells, American Oil & Gas Historical Society; various state agencies; and Texaco Production Operations

APPENDIX

K

An aerial photograph of a coastline, showing a mix of blue water and green land. The water is a deep blue, and the land is a vibrant green. The coastline is irregular, with many small inlets and peninsulas. The overall tone is bright and natural.

Untapped Potential

Offshore Oil and Gas Resources Inaccessible to Leasing

A Report by the Interstate Oil and Gas Compact Commission's North American Coastal Alliance

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The background of the entire page is a photograph of an offshore oil rig. The rig's complex steel structure, including cranes and platforms, is silhouetted against a bright, orange-hued sky at sunset or sunrise. The rig extends from the dark, choppy surface of the ocean. The overall tone is industrial and dramatic.

About the North American Coastal Alliance

The North American Coastal Alliance (NACA) is a workgroup comprised of Interstate Oil and Gas Compact Commission (IOGCC) members whose states or provinces are located along coastlines.

The NACA focuses on areas of concern to coastal states and provinces through a forum of open dialogue and sharing of compliance information and environmental research results. In many areas, oil, gas and marine ecosystems represent a continuum between state/provincial and federal waters.

The IOGCC is a multi-state government agency that champions conservation and efficient recovery of the nation's oil and natural gas resources while protecting health, safety and the environment. Chartered by Congress in 1935, the organization consists of the governors of 37 states (30 members and seven associate states) that produce most of the oil and natural gas in the United States, as well as seven international affiliates.

IOGCC member states participating in the NACA include Alabama, Alaska, California, Florida, Louisiana, Mississippi, Texas, Virginia and Canadian provinces British Columbia, Newfoundland and Labrador, and Nova Scotia. The U.S. Department of Energy provides a significant amount of funding for NACA activities.

Executive Summary

This report presents the results of a collaborative effort of member states and provinces making up the North American Coastal Alliance (NACA), a workgroup of the Interstate Oil and Gas Compact Commission (IOGCC).

The report is intended to provide a complete characterization of potential offshore oil and natural gas resources in North America that are currently unavailable for leasing and development.

The intent of the NACA in this report is to compile information to facilitate informed decision-making regarding future opportunities associated with potential oil and gas resources in these areas currently unavailable for leasing and development, not to recommend policy.

North American offshore moratorium areas are estimated to contain nearly 135 trillion cubic feet (Tcf) of natural gas and more than 30 billion barrels of crude oil (estimates are mean values). To provide some context, estimated technically recoverable oil and natural gas resources in these areas represent an amount comparable to current proved reserves in the United States. As of December 31, 2004, proved U.S. crude oil reserves amounted to 21.4 billion barrels and proved natural gas reserves (dry) were estimated to be 192.5 Tcf.¹

Regardless of the existence of areas subject to moratoria and/or executive withdrawals, offshore oil and natural gas production in North America currently plays, and will continue to play, an important role in the energy picture of the United States and Canada. In fact, offshore production from the Outer Continental Shelf (OCS) of the Gulf of Mexico and California accounts for 29 percent of U.S. oil production (double the contribution of offshore production only 12 years ago) and 21 percent of U.S. natural gas production. This is a result of both an increase in production from the federal OCS and a decrease in onshore production.

In Canada, oil production from the offshore areas of Eastern Canada accounts for roughly 10 percent of total Canadian oil production, including bitumen. Offshore natural gas production in Eastern Canada accounts for approximately 2 percent of total Canadian natural gas production.

If the potential resources in areas that have been withdrawn from leasing or are under moratoria could be developed, they would play an important role in meeting future North American energy requirements from hydrocarbon resources on the continent. Therefore, it is important for citizens and policy makers to understand the significance of these potential North American oil and gas resources when making energy development decisions.

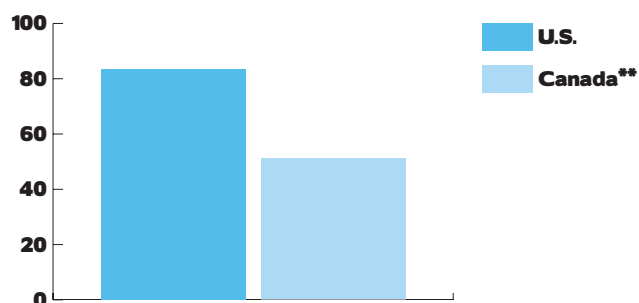
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At a Glance

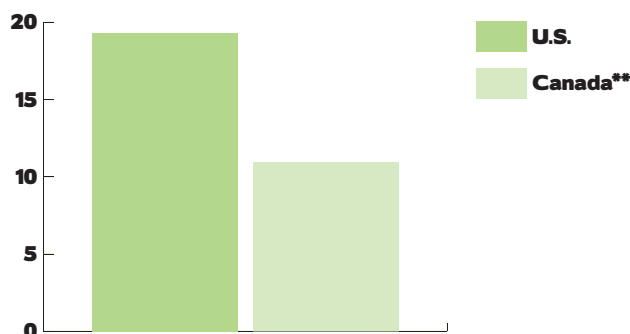
Estimate of Undiscovered Technically Recoverable Resources in Moratorium Areas*

	Gas (Tcf)	Oil (Bbbls)
United States - Federal OCS	77.95	18.07
United States - Nonfederal	5.55	1.22
Total United States	83.50	19.29
Total Canada**	51.10	10.96
TOTAL U.S. and Canada	134.60	30.25

Natural Gas (Tcf)



Crude Oil (Bbbls)



* No areas in offshore Mexico were considered in this analysis.

** Estimates for British Columbia are median in-place resources.

Characteristics of Resource Estimates

Resource estimates described in this report are undiscovered technically recoverable resources,** or the portion of the hydrocarbon estimated on the basis of geologic knowledge and theory to exist outside known accumulations, that are recoverable with current technology. The economic feasibility of recovering these resources is not considered. This is in contrast to the resource in-place, which represents the total hydrocarbon volume present without regard to recoverability. This value can be considered fixed and is determined only by the local geologic conditions. In contrast, the technically-recoverable portion of the resource is not fixed, but tends to grow with time as a result of experience and technology improvements.

There is much uncertainty associated with estimating undiscovered resources. Estimates are generally presented in terms of: 1) a high or optimistic estimate, 2) a low or conservative estimate, and 3) a mean value, which is the arithmetic average of all values in the distribution.

In this report, only mean values are reported.

Estimates in this report are based on existing knowledge of oil and gas resources in North American offshore waters and may change after additional exploration.

Introduction

SUPPLY AND DEMAND PROJECTIONS

A general tightening of world hydrocarbon supply and growing demand is causing hydrocarbon prices to increase, putting growing financial burdens on North American consumers.

The United States consumes more petroleum than it currently produces, and is the world's largest importer of crude oil and petroleum products. In 2004, nearly 5.7 billion barrels of crude oil were supplied to U.S. refineries. Of this, nearly 2 billion barrels came from U.S. production, including about 564 million barrels of oil (31 percent) from U.S. offshore production.² To satisfy its supply requirements, the United States imported 3.7 billion barrels of crude oil, representing nearly two-thirds of U.S. oil supplies.³ More importantly, the Energy Information Administration (EIA) currently forecasts that the United States will require 7.6 billion barrels of crude oil annually by 2025, an increase of 33 percent.⁴

In addition, the United States consumed almost 22.4 Tcf of natural gas in 2003. In 2004, the United States produced more than 20 Tcf (wet) of natural gas, in-

cluding about 4.0 Tcf (20 percent) from U.S. offshore production. Most of the remaining demand was met by natural gas imports from Canada, with a relatively small portion met by imports of liquefied natural gas (LNG).⁵ As with the oil forecast, U.S. natural gas consumption is predicted to grow to 30.6 Tcf annually by 2025, an increase of nearly 37 percent.⁶

Today, approximately 8 percent of U.S. oil supply and 14 percent of U.S. natural gas supply comes from Canada. Canada's future capability to deliver oil and natural gas resources to the United States depends on many factors, including Canada's own energy needs. Canada consumes more than 784 million barrels of oil and 3.1 Tcf of gas annually, while producing 876 million barrels of oil and 7.8 Tcf of gas annually, making Canada a net exporter of oil and gas. Similar to the United States, Canada's oil consumption is forecast to grow 29 percent by 2025. While conventional oil production is forecast to decline by 30 percent, Canadian production of unconventional oil is massive, and recovery from oil sands deposits is forecast to increase nearly four-fold over this same time period.⁷ Canada will remain a net exporter of oil for the foreseeable future.

On the other hand, growth in Canadian natural gas production is not expected to keep pace with demand, so the amount of U.S. natural gas imports coming from Canada is forecast to decline.

Combined, the United States and Canada are net importers of crude oil, and are essentially self-sufficient in natural gas. However, as oil and gas demand continues to increase, it is estimated that the portion of U.S. and Canadian combined petroleum needs that will be met by imports will continue to grow. Moreover, as gas demand continues to grow, these two countries also could become a net importer of natural gas in the future.

The offshore areas of the United States and Canada provide some of the last frontiers on the continent for new potential conventional hydrocarbon supply sources. However, it is important to acknowledge that new offshore discoveries, depending on whether or not they are in developed or undeveloped basins, can typically take up to 15 years to reach the market. Therefore, plans made today to develop new offshore oil and gas resources may not result in corresponding production until between 2015 and 2020.

² Minerals Management Service, MMS/MRN, May 2005 (<http://www.mms.gov/stats/OCSproduction.htm>).

³ Energy Information Administration, *Petroleum Supply Annual 2004*, Volume 1, Table 1.

⁴ Energy Information Administration, *Annual Energy Outlook 2005*, Table A11.

⁵ Energy Information Administration, *Natural Gas Annual 2003*, Table 1.

⁶ Energy Information Administration, *Annual Energy Outlook 2005*, Table A13.

⁷ Energy Information Administration, *Annual Energy Outlook 2005*, Table A20.

PURPOSE OF THIS REPORT

The purpose of this study is to report on the hydrocarbon resource potential in offshore areas of the United States and Canada that currently are under leasing moratoria or are otherwise withdrawn or excluded from exploration, drilling and production by legislation or policy.

This report is unique in that it is the first complete compilation of data on resources that are not available for leasing and development in the offshore waters of the United States and Canada, including those in state and federal waters of the United States, and those in federal and provincial waters of Canada.

The report outlines the areas under moratoria or otherwise inaccessible, and presents current estimates of oil and gas resources in those areas.⁸ The report can be used as a quick reference document that summarizes the supply potential currently inaccessible to leasing and development.

DEFINITION OF MORATORIUM AREAS

NACA defines “moratorium areas” as those offshore that effectively have restrictions, whether through leg-

islation or policy, which preclude exploration and development activity. In the United States, these include areas that have been subject to congressional moratoria or presidential withdrawal from leasing, and include: (1) presidential withdrawal of additional leasing under Section 12 of the Outer Continental Shelf Lands Act until after June 30, 2012, applying to all of California, Oregon, and Washington, and specific areas on the East Coast; and (2) long-running congressional leasing moratoria enacted annually as part of the Department of Interior’s appropriations which, in addition to the aforementioned areas, apply to the U.S. Atlantic Coast, the eastern Gulf of Mexico (except for areas proposed, but not offered, as part of Lease Sale 181 in 2001) and, until 2004, the North Aleutian Basin in Alaska.

For Canada off the West Coast, in 1972, the federal government placed a policy moratorium on tanker traffic in the Inside Passage coming from Alaska and on offshore exploration activity. In 1989, in response to the Exxon Valdez oil spill and the Nestucca barge oil spill, the Province of British Columbia placed a policy moratorium on offshore oil and gas exploration

and development. In 2003, the provincial government asked the federal government to consider lifting the moratorium. The federal government undertook a scientific review, a public review, and a First Nations Engagement Process; and is considering its position as of the date of this report. The moratorium on Georges Bank off Nova Scotia was extended to 2012 and corresponds with the presidential moratorium on the U.S. side of Georges Bank.

Throughout the remainder of this report, use of the term “moratorium areas” refers to those in the United States subject to congressional moratorium and/or presidential withdrawals, and those areas in Canada also subject to moratoria.

MORATORIUM AREAS CONSIDERED

In this report, the areas currently impacted by a ban on leasing and/or exploration and development in the United States include: (1) Offshore Alaska, which includes the North Aleutian Basin planning area and the Alaska-owned waters of Kachemak Bay; (2) the Offshore Atlantic planning areas of North Atlantic, Mid-Atlantic, South Atlantic, and the Straits of Florida; (3)

⁸ For purposes of this study, estimates of resource potential for moratoria/withdrawal areas in the U.S. federal OCS were provided by the U.S. Minerals Management Service based on the 2003 National Assessment. For state and provincial waters, estimates generally are based on information provided by the state and provincial governments.

Offshore Eastern Gulf of Mexico (except for the areas proposed, but not offered, as part of Lease Sale 181); (4) the unleased areas of the Offshore Pacific, which includes the states of California, Oregon and Washington; and (5) the Great Lakes Region.

In Canada, the areas currently under moratoria that are believed to have hydrocarbon resource potential include: (1) the West Coast of British Columbia and (2) Georges Bank off Nova Scotia. Lancaster Basin in Northern Canada had exploration activity suspended from 1976 to 1997 for environmental assessment purposes and remains a very environmentally sensitive area.

INTEGRATED MANAGEMENT OF COASTAL AND OFFSHORE INTERESTS

The environmental concerns associated with exploration and development of oil and natural gas must be weighed against the benefits that these energy resources could potentially provide. This is particularly true in coastal and offshore areas.

The governments of the United States and Canada are striving to develop management plans that balance all competing uses and promote national economic opportunities without compromising the coastal and offshore environments. These management plans necessarily must include varying, site-specific accommodations and requirements, as well as appropri-

ate mitigation measures. For example, in 1972, U.S. Congress enacted the Coastal Zone Management Act (CZMA), which established a program to encourage voluntary partnerships between the federal government and coastal states dedicated to comprehensive management of the nation's coastal resources to preserve, protect, develop, restore and enhance coastal zone resources while balancing competing national economic, cultural and environmental interests. The CZMA requires that each federal activity within or outside the coastal zone that affects areas and natural resources in the zone be consistent with the goals and policies of the appropriate state coastal management program. State coastal management programs must anticipate and plan for effects of energy facilities. In practice, CZMA affords the states broad discretion in the extent of energy activities, including offshore oil and gas development, to be allowed.

In many areas, the nations have not imposed wholesale moratoria on large blocks of the offshore, but have determined that some areas are so unique and sensitive as to preclude any activity. For example, the U.S. National Marine Sanctuary Program, administered by the National Oceanic and Atmospheric Administration, manages and protects specially designated areas of the nation's oceans and Great Lakes for their habitat, ecological value, threatened and endangered species, and historic, archeological, recreational, and aesthetic re-

sources. Thirteen national marine sanctuaries are part of this program, with steps currently underway to designate one additional coral reef ecosystem as the 14th national marine sanctuary.

In Canada, there also are a variety of federal and provincial legislative designations to protect the marine environment, including marine protected areas, national marine conservation areas, national parks with marine components, marine wildlife areas, migratory bird sanctuaries as well as those provincial parks or recreation areas, ecological reserves, protected areas and wildlife management areas, established in a marine environment.

Both the United States and Canada require environmental assessments of areas proposed for development. In the United States, under the National Environmental Policy Act (NEPA) of 1969, federal agencies must include an environmental review process early in the planning for proposed actions to help public officials make decisions based on an understanding of environmental consequences and take actions that protect, restore, and enhance the environment. In Canada, virtually all phases of offshore oil and gas activity are subject to some form of environmental assessment or review. In areas of federal jurisdiction, the Canadian Environmental Assessment Act (CEAA) applies. The primary purpose of CEAA is to ensure that environ-

mental assessment is undertaken as early as possible in the project planning and approval process before irrevocable decisions are made.

In both Canada and the United States, federal and state/provincial governments require mitigation of adverse impacts.

Outside of the current moratorium areas, responsible exploration and development in sensitive and/or unique environments can, and does, occur. Appropriate and reasonable restrictions and/or stipulations can be imposed on exploration and development activities that would ensure protection of these environments. In both the United States and Canada, an oil and gas operator must take steps, regardless of jurisdiction, to ensure that the environment is appropriately protected. Offshore oil and gas exploration and production activities are subject to environmental restrictions and mitigation requirements imposed by both federal and state/provincial government, from the initial leasing of areas for exploration to the ultimate decommissioning of offshore platforms.

For example, in the Alaska offshore, specific areas within the Beaufort Sea lease areas are deferred or withdrawn from the lease offerings, especially areas related to protecting habitat, cultural resources and subsistence fishing. For those areas that are available for lease, stipulations on exploration and development are imposed to ensure protection of sensitive biological populations and habitat. In addition, lessees must develop oil spill response plans, which must include identification and appropriate measures to ensure protection of areas of special biological and cultural sensitivity.

RECENT POLICY INITIATIVES - UNITED STATES

Concerns over energy supply in the United States have many looking for innovative ideas to gain access to restricted areas with petroleum potential. At the federal level, several legislative initiatives have been proposed to modify state offshore boundaries, enhance revenue/impact sharing with the states, and give states greater control over leasing in federal waters off their shores that have previously been under moratoria for leasing and development. Some states are also taking major

steps to encourage additional oil and gas development off their coasts.⁹

Arguably the most important legislative actions affecting offshore oil and gas development activities are represented in provisions in the Energy Policy Act of 2005 that:

- Authorize the Department of Interior (DOI) to develop an inventory of oil and gas resources on the OCS, including those areas under moratoria.
- Prohibit the issuance of any new federal or state lease in the Great Lakes for oil and gas drilling, whether from offshore or onshore directional wells.
- Amend the Coastal Zone Management Act to establish a 160-day deadline for closure of the CZMA administrative record, unless the Secretary of Interior stays this deadline to receive supplemental/clarifying information.

⁹ South Carolina General Assembly, 116th Session, 2005-2006, H. 4128 (http://www.scstatehouse.net/sess116_2005-2006/bills/4128.htm). Virginia General Assembly, 2005-2006 HB1132 (<http://leg1.state.va.us/cgi-bin/legp504.exe?061+sum+HB1132>).

- Provide a variety of incentives to avoid the premature abandonment of marginal oil and gas production and stimulate new development of resources underlying federal lands.
- Establish a financial assistance program for coastal states with offshore oil and gas production, to assist in coastal enhancement, restoration and conservation programs.
- Direct DOE to establish a research and development program for ultra-deep and unconventional natural gas and other petroleum resources.

RECENT POLICY INITIATIVES - CANADA

In 1997, Canada's Oceans Act, comprehensive oceans management legislation, came into force. This was followed by Canada's Oceans Strategy in 2002, the federal government's policy for the "management of estuarine coastal and marine environments." In 2005, the federal government published its Oceans Action Plan. "The plan serves as the overarching umbrella for coordinating and implementing oceans activities, and as the framework to sustainably develop and manage our oceans."

The Oceans Action Plan is based on four pillars: (1) International Leadership, Sovereignty and Security (2) Integrated Oceans Management for Sustainable De-



velopment (3) Health of the Oceans; and (4) Oceans Science and Technology.

In 2004, Canada and British Columbia entered into a Memorandum of Understanding respecting the imple-

mentation of Canada's Ocean Strategy off the Pacific Coast of Canada. The purpose of the MOU is to advance collaboration between the parties to implement specific activities and objectives identified in Canada's Oceans Strategy.

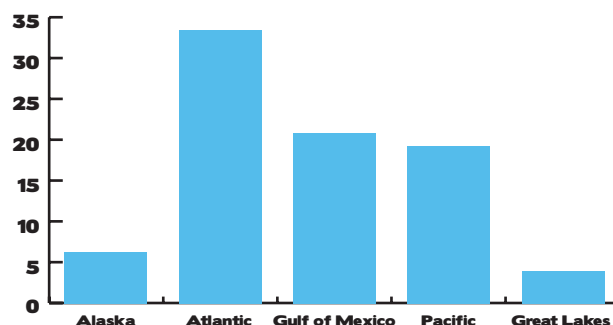
United States Overview

A mean estimate of the undiscovered natural gas underlying U.S. moratorium areas is approximately 83.5 Tcf, and mean undiscovered crude oil is estimated to be 19.3 billion barrels.

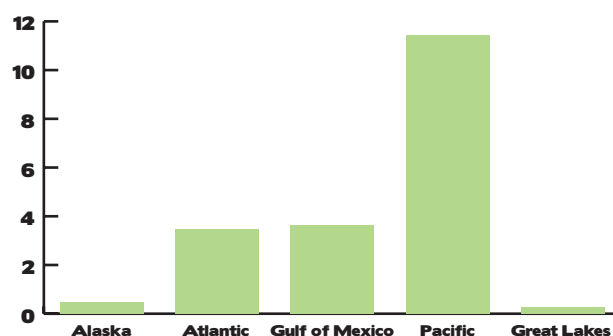
The National Petroleum Council in 2003 estimated mean undiscovered natural gas resources in moratorium areas to be 79 Tcf,¹⁰ but excluded the Alaska OCS, the Great Lakes, and state waters from this estimate.

The updated review by the Minerals Management Service (MMS) in 2003 showed that the estimates of resource potential in most regions remain close to the 2000 numbers. The most dramatic increase is in the Eastern Gulf of Mexico area, in which the estimates increased from 8.5 to more than 20 Tcf of gas and from 2.7 to 3.65 billion barrels of oil. These increases are primarily the result of new field discoveries resulting from the recent leasing of tracts in the Eastern Gulf.

Potential Natural Gas



Potential Crude Oil



Offshore U.S.

Estimate of Undiscovered Technically Recoverable Crude Oil and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
Alaska	6.23	0.48
Atlantic	33.34	3.45
Gulf of Mexico	20.72	3.65
Pacific	19.21	11.44
Great Lakes	4.00	0.27
TOTAL	83.50	19.29

¹⁰ National Petroleum Council, *Natural Gas – Meeting the Challenges of the Nation's Growing Natural Gas Demand*, Volume 1, Summary Report, 2003.

Alaska

There are two moratorium areas associated with the state of Alaska. The first affects waters in the North Aleutian Basin OCS planning area (formerly the Bristol Bay Basin planning area). The second affects state waters in Katchemak Bay, which is located in the southern portion of the Cook Inlet Basin between Point Pogibshi and Anchor Point on the Kenai Peninsula.

FEDERAL - NORTH ALEUTIAN BASIN

Congress established a moratorium on leasing and drilling for the North Aleutian Basin OCS in October 1989. The moratorium was extended several times during the 1990s by federal legislation but was eventually discontinued by Congress. However, on June 12, 1998, the basin was withdrawn from leasing by presidential order until June 30, 2012.

Oil companies that had acquired leases in the planning area prior to the imposition of the moratorium brought suit against the federal government. In 1995, in a settlement with Chevron Oil Company, the federal government bought back the North Aleutian OCS leases for a reported 10 percent of the original lease acquisition costs.

The leasing moratorium originally had wide support of the commercial fishing industry, as well as native and environmental groups. However, the fishing industry subsequently has crashed economically, and many of the local residents, including fishermen, have reconsidered, and now support leasing and developing the hydrocarbon resources on native, private, state and federal leases.

STATE - NORTH ALEUTIAN BASIN

The state of Alaska, one of the original proponents of the federal OCS moratorium, had maintained an ad hoc moratorium in the North Aleutian Basin state waters from the late 1980s through 2004. In response to the change in attitude toward possible oil and gas development by the local Bristol Bay population, the state has initiated a program of oil and gas exploration incentives in the North Aleutian Basin. On December 16, 2004, an exploration license in the general vicinity of Dillingham, Alaska was awarded on 329,000 acres of primarily onshore lands.

The state of Alaska also has completed a best interest finding for a North Aleutian Basin lease offering in-

volving approximately 4.5 million gross onshore and offshore acres. On October 26, 2005, the state of Alaska conducted its first lease sale in offshore state waters in the Bristol Bay area.¹¹ This Alaska Peninsula area-wide sale encompassed 1,047 tracts ranging in size from 1,280 to 5,760 acres in an area that stretches from the Nushagak Peninsula in the north, down the north side of the Alaska Peninsula to just north of Cold Bay.

STATE - KATCHEMAK BAY

Katchemak Bay in the southern portion of the Kenai Peninsula in state waters is the location of several important fishing ports and a number of aquaculture projects. In 1976, a state law was passed prohibiting oil and gas activities in the area. The prohibition followed an oil and gas lease sale in the area, and was then followed by a lease buy back by the state government, in a series of events that are similar to those described for the North Aleutian Basin federal OCS. The area of the prohibition was modified in 1986, and now comprises approximately 150 square miles. Several oil and gas wells have been drilled either adjacent to or within Katchemak Bay. These wells have encountered porous sandstones with significant gas shows, though

¹¹ Alaska Department of Natural Resources, Division of Oil and Gas, *Notice of Competitive Oil and Gas Lease Sale and Issuance of Final Best Interest Finding and Alaska Coastal Management Program Determination for Alaska Peninsula Area Wide 2005*, July 25, 2005 (http://www.dog.dnr.state.ak.us/oil/products/publications/akpeninsula/2005/sale_notice.pdf).

no strong evidence of hydrocarbon liquids has yet been encountered in the immediate area.

RESOURCES UNDER MORATORIA

Outcropping portions of the North Aleutian Basin Tertiary fill and the underlying Mesozoic sequence on the Alaska Peninsula are associated with common oil seeps and oil staining.¹² The evidence of oil in these rocks is so strong that the Alaska Peninsula was one of the first areas drilled in the early 20th Century.

The sparsely drilled North Aleutian Basin contains a primarily non-marine Tertiary basin fill overlying a complex series of Mesozoic predominantly marine sediments. The MMS estimates indicating a gas prone hydrocarbon charge are influenced strongly by geochemical analysis from wells that have not penetrated mature oil-prone source rocks.

The MMS has performed independent assessments of the economically recoverable undiscovered oil and gas resource in the North Aleutian Basin three times in recent years (1995, 2000, and 2005 {in press}). The most recent MMS estimate is based on a substantially differ-

ent set of assumptions and methodologies compared to early MMS assessments. The most recent mean undiscovered resource estimates are 480 million barrels of oil and 6.18 Tcf of natural gas.

The North Aleutian Basin is highly analogous to the Cook Inlet Basin, a prolific oil and gas-producing basin in south-central Alaska. The similarities in these basins are especially relevant in the distribution of hydrocarbon source and reservoir rocks. Because of the significant hydrocarbon resource potential discovered in the Cook Inlet Basin (greater than 1.4 billion barrels of oil and 8.4 Tcf of natural gas), some geologists believe that the hydrocarbon resource potential in the North Aleutian Basin should be similar, and the MMS estimates of undiscovered resource potential in the basin may be too low.

For the purposes of this report, an undiscovered economically recoverable gas resource estimate for Katchemak Bay of 50 billion cubic feet (Bcf) was determined to be appropriate.¹³

Offshore Alaska

Estimate of Undiscovered Technically Recoverable Crude Oil and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
North Aleutian Basin*	6.18	0.48
Katchemak Bay**	0.05	-
TOTAL	6.23	0.48

* Estimates provided by the U.S. Mineral Management Service based on the 2003 National Assessment.

**Estimates provided by the Alaska Oil and Gas Conservation Commission for the purposes of this report.

Alaska Coast



¹² Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Peninsula Lease Sale: New DNR Geologic Report*, Media Release October 28, 2005 (http://www.dnr.state.ak.us/standard/dsp_media_release.cfm?id=543&title=Alaska%20Peninsula%20Lease%20Sale%3A).

¹³ This estimate is based on an Alaska Oil and Gas Conservation Commission preliminary assessment that is based on onshore reserves covering a similar area just to the north, as analog to the Katchemak Bay. Although the section is thinner, there is at least one potential structure that could hold 50 Bcf of natural gas.

Atlantic Coast

FEDERAL - OFFSHORE ATLANTIC

Ten oil and gas lease sales were held in the Atlantic OCS between 1976 and 1983, where 9,240 blocks were offered and 433 leased.

A total of 49 exploratory wells and five Continental Offshore Stratigraphic Test (COST) wells were drilled.¹⁴ Five wells discovered hydrocarbons, but were abandoned as non-commercial.

The Atlantic OCS, as defined by MMS, is divided into four planning areas along the Atlantic Seaboard: the North Atlantic, Mid-Atlantic, South Atlantic and the Straits of Florida:

- North Atlantic - The North Atlantic planning area lies offshore of the northeast portion of the United States extending from Maine to New Jersey. The area encompasses approximately 48.8 million acres (8,840 blocks). The main prospective areas are the Georges Bank area off Cape Cod, and the Baltimore Canyon Basin off Atlantic City. There was one lease sale in the late 1970s, with eight exploratory wells and two COST wells drilled. Between

1983 and 1990, most of the North Atlantic was withdrawn from leasing. The most recent scheduled lease sale in the North Atlantic was canceled.

- Mid-Atlantic - The Mid-Atlantic planning area lies offshore the Middle Atlantic states and extends from Rhode Island to North Carolina. The main prospective area is the Carolina Basin. The area encompasses approximately 82.2 million acres, and has had the most lease sales (five) in the Atlantic region (between 1976 and 1983), the majority of leases awarded, and the most wells drilled (32 exploratory, two COST). Most of the Mid-Atlantic was withdrawn from leasing in 1983. Eight leases remained active until November 17, 2000, when the interests in these leases in the federal waters offshore North Carolina were relinquished by Conoco, Shell Offshore and OYX USA.
- South Atlantic - The South Atlantic planning area lies offshore of the southern Atlantic states and extends from North Carolina to Florida. The main prospective area is the Southeast Georgia Embayment. The area encompasses approximately 114.2

million acres. No leases currently remain active. Several lease sales were held between 1978 and 1983, and six exploratory wells and one COST well were drilled in this area. Since 1983, all scheduled lease sales were either canceled or deferred, until the entire area was placed under moratorium in 1998.

- Straits of Florida - The Straits of Florida planning area in the Atlantic region lies offshore Florida, with the only lease sale in this area held in 1959. The Straits of Florida is not under moratorium since MMS canceled the last proposed sale in this area (Sale 140) in early 1998, as part of a litigation settlement on its five-year Program. There are no active leases in this area.

Regardless of the divisions in the MMS Atlantic OCS area, the geological setting ties all of these areas together and connects Nova Scotia to the Atlantic Mesozoic environment (see discussion on the Nova Scotia region of Canada for details).

¹⁴ The Continental Offshore Stratigraphic Test (COST) well program was a federal government drilling program in the 1970s where energy company consortiums were allowed to drill a limited number of test wells to gain geologic information prior to anticipated federal leasing.

STATE - OFFSHORE ATLANTIC

No information is available from Maine to Florida on potential resource estimates in state waters off states adjacent to the Atlantic moratorium areas.

RESOURCES UNDER MORATORIA

The most recent MMS estimates for mean undiscovered resources in the moratorium areas of the Atlantic OCS are 3.45 billion barrels of oil and 33.34 Tcf of natural gas.

Offshore Atlantic*

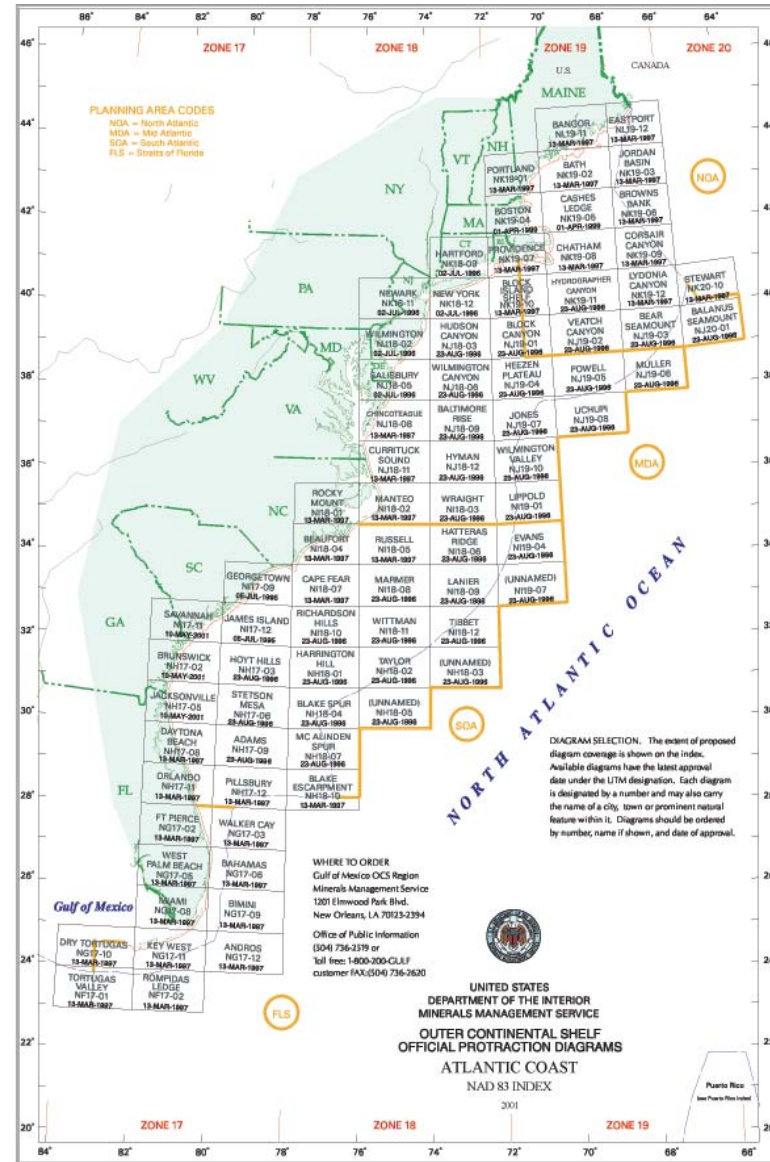
Estimate of Undiscovered Technically Recoverable Crude Oil and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
North Atlantic	n/a	n/a
Mid Atlantic	n/a	n/a
South Atlantic	n/a	n/a
Straits of Florida	n/a	n/a
Atlantic State Waters**	n/a	n/a
TOTAL	33.34	3.45

* Estimates provided by the U.S. Mineral Management Service based on the 2003 National Assessment. No breakdown by Planning Area was provided.

** For the purposes of this report, no estimates were provided for state waters off the Atlantic coast.

Atlantic Coast



Gulf of Mexico

On August 20, 2003, the U.S. Department of Interior celebrated the 50th anniversary of the Outer Continental Shelf Lands Act, as it reviewed bids for the Western Gulf of Mexico Lease Sale 187. This lease sale was the 100th offshore oil and gas lease sale conducted in the Gulf of Mexico. According to Secretary of Interior Gale Norton, “Over the past 50 years, lease sales ... have produced about 14 billion barrels of oil and about 150 trillion cubic feet of natural gas. They have also provided oil-in-kind to help fill the Strategic Petroleum Reserve, created thousands of jobs, and generated \$145 billion in revenue from federal offshore collections.”

FEDERAL - EASTERN GULF OF MEXICO OCS

However, not all of the Gulf of Mexico federal OCS is currently accessible for leasing and development. Leasing in the Eastern Gulf of Mexico has been limited over the last several decades. The Eastern Gulf planning area extends along the Gulf’s northeastern coast for some 1,120 kilometers (700 miles) from Baldwin County, Alabama, southward to the Florida Keys. The area encompasses approximately 76 million acres, with water depths ranging from tens of meters to more than 3,000 meters (9,900 feet). Seaward of the state/federal boundary (three leagues or roughly nine miles off the Florida coast), the area extends southward for more than 480 kilometers (300 miles).

Drilling for natural gas and oil first took place in the Eastern Gulf of Mexico offshore Alabama and Florida more than three decades ago. The first sales held offshore Florida occurred in 1959 and resulted in 23 leases being issued. Exploratory drilling started in the Eastern Gulf of Mexico in the mid-1970s with the drilling of Destin Dome Block 162, located 64 kilometers (40 miles) south of Panama City, Florida. After two years of drilling and 15 dry holes, exploration ground to a halt. The 1980s ushered in three Eastern Gulf lease sales and renewed industry interest in this area. Finally, in the late 1980s, Chevron and Gulfstar made natural gas discoveries in the area. In October 1995, 73 oil and gas leases located south of 26 degrees north latitude were returned to the federal government as part of a litigation settlement.

Additional lease sales were held in the Eastern Gulf between 1973 and 2001. Lease Sale 181 in the Eastern Gulf of Mexico in 2001 initially offered a 6 million-acre expanse about 15 miles off the coast of Florida - a tract excluded from federal moratoria on new offshore oil leases that applies elsewhere. In July 2001, prior to the scheduled sale, the area offered was reduced to 1.5 million acres, and the sale’s boundaries were adjusted. In the revised sale area, drilling can occur no closer than 100 miles offshore from Pensacola and 285 miles from Tampa. Subsequent leases in this reduced area have been offered.

Currently, there are 241 active leases in the Eastern Gulf of Mexico planning area. To date, more than 60 exploratory wells have been drilled in the Eastern Gulf and 20 wells have discovered natural gas, condensate, and/or crude oil.

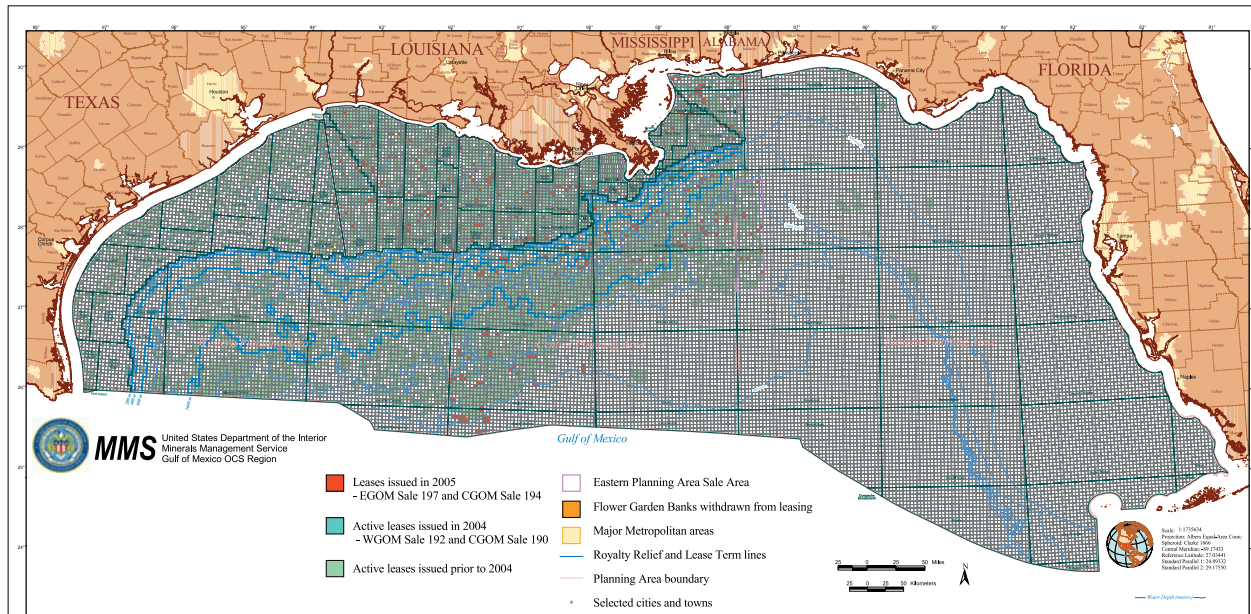
STATE WATERS IN THE GULF OF MEXICO

There are no moratoria in Texas, Alabama and Louisiana state waters. Essentially 75 percent of the 500,000 offshore acres off the coast of Mississippi are restricted from being leased for oil and gas. Moreover, in Mississippi, a bill was enacted in 2004 (Senate Bill 2853) that, among other things, prohibits mineral leasing of offshore lands except for certain blocks south of the state’s barrier islands.

RESOURCES UNDER MORATORIA

In 2000, MMS estimated that between 10 and 18.9 Tcf of natural gas, and between 2.35 and 6.61 billion barrels of oil and condensate, were contained in the Eastern Gulf of Mexico federal OCS planning area. However, based on recent drilling successes, since Sale 181, these estimates have been increased substantially. The most recent MMS assessment of mean technically recoverable undiscovered oil and gas resources in the Eastern Gulf of Mexico is 3.65 billion barrels of oil and 20.22 Tcf of natural gas.

Gulf of Mexico



Gulf of Mexico*

Estimate of Undiscovered Technically Recoverable Crude Oil and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
Eastern Gulf	20.22	3.65
Gulf Coast State Waters**	0.50	-
TOTAL	20.72	3.65

* Estimates provided by the U.S. Mineral Management Service based on the 2003 National Assessment. No breakdown by planning area provided.

**For the purposes of this report, no moratorium areas existed in Alabama, Louisiana and Texas. Mississippi state waters currently under moratorium are estimated to contain 500 Bcf of natural gas.

In Mississippi state waters, an estimated 250 to 750 Bcf of technically recoverable resources correspond to the areas currently under moratoria.¹⁵ For purposes of this report, 500 Bcf was assumed for this area. Therefore,

this amounts to total estimated resources under moratoria in the Gulf of Mexico (federal and state waters) of 3.65 billion barrels of oil and 20.7 Tcf of natural gas.

¹⁵ Mississippi Mineral Resources Institute, *Overview of Miocene Hydrocarbon Potential of Mississippi Sound and the Adjacent Onshore Areas*, Open File Report 04-2, February 5, 2004.



Pacific Coast

FEDERAL - PACIFIC OCS

All of California, Oregon and Washington have been subject to long-running leasing moratoria enacted annually as part of the U.S. Department of Interior's appropriations legislation. These states are split into four OCS planning areas: Washington-Oregon, Northern California, Central California and Southern California. Under authority of Section 12 of the OCS Lands Act, all of these areas were withdrawn from leasing until after June 30, 2012, and all National Marine Sanctuaries were indefinitely withdrawn from leasing. The congressional moratoria and Section 12 withdrawal do not apply to existing leases. There are 79 active OCS leases in Central and Southern California, of which 43 are developed and 36 undeveloped.

California is currently a substantial offshore producer. In 2004, the Pacific OCS produced, on average, more than 75,000 barrels of oil per day and nearly 150,000 Mcf of gas per day from 14 fields.¹⁶

In the Washington-Oregon planning area, a total of 12 exploratory wells were drilled, and 101 leases were issued, all of which have expired or were relinquished. In

the Northern and Central California planning areas, there were 20 exploratory wells drilled on 57 leases, all of which have been relinquished.

The Southern California planning area has seen 977 development wells (not under moratoria), 297 exploratory wells (several in moratorium areas) and a total of 312 leases. Of those, 79 leases are active and 43 are producing. Those remaining have expired, have been relinquished, or have been terminated. Remaining proved and unproved reserves not under federal OCS moratoria (from the active leases) are estimated to be 1.47 billion barrels of oil and 1.48 Tcf of natural gas.

STATE - OFFSHORE PACIFIC

In June 2005, California state offshore production was 41,500 barrels of oil per day and 18,400 Mcf of natural gas per day, according to the California Department of Conservation. The majority of this production is from the offshore production islands in Wilmington oil field in the Los Angeles Basin. Both Washington and Oregon currently have moratoria in place:

- Washington Statute Section RCW 43.143.010

prohibits leasing in tidal waters and submerged lands out to 3 miles along the entire coast, and parts of the Columbia River.

- Oregon Statute Section ORS 196.410 is a legislative finding for offshore oil and gas leasing and states that Oregon is unwilling to risk damaging sensitive marine environments or to sacrifice environmental quality to develop offshore oil and gas resources.

In addition, California Statute Section PRC 6242 defines all state waters (three-mile limit) not subject to a lease effective January 1, 1995, as a California Coastal Sanctuary and prohibits future leasing. Furthermore, the California Coastal Commission presented a resolution on April 5, 2004, asking the federal government to prevent development of the 36 undeveloped federal leases. The Coastal Commission also referenced recent court decisions under the Coastal Zone Management Act (CZMA) that affirm California's right to review and approve these lease developments.

RESOURCES UNDER MORATORIA

Undiscovered technically recoverable resources in fed-

¹⁶ Source: U.S. Minerals Management Service (2005) (<http://www.mms.gov/stats/OCSproduction.htm>).

eral OCS moratorium areas for the Pacific OCS are estimated to be 10.5 billion barrels of oil and 18.2 Tcf of natural gas. In addition, the California Coastal Lands Commission estimates that 950 million barrels of crude oil and 1 Tcf of natural gas exist in state waters currently under a state leasing moratorium. Therefore, total estimated hydrocarbon resources in areas under moratoria in the West Coast (state and federal waters) amount to 11.4 billion barrels of oil and 19.2 Tcf of natural gas.

Offshore Pacific*

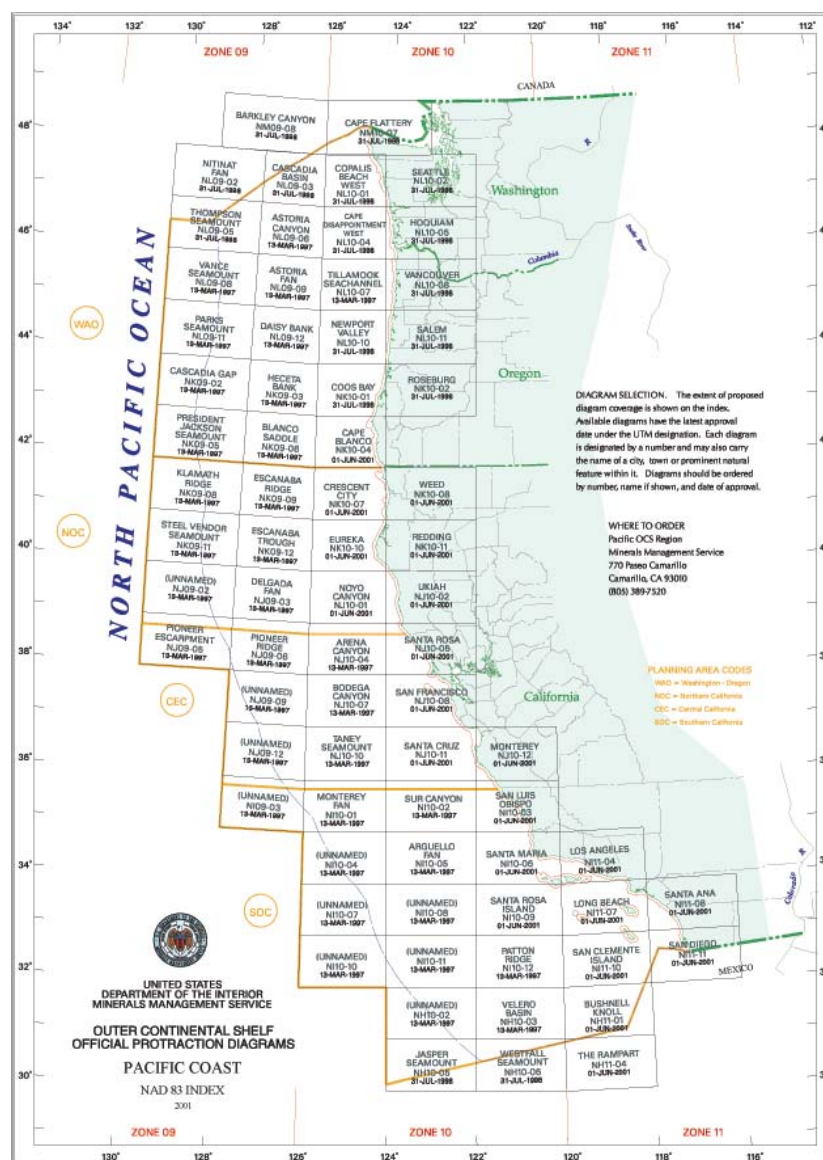
Estimate of Undiscovered Technically Recoverable Crude Oil and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
Washington/Oregon	2.26	0.35
Northern California	3.56	2.04
Central California	2.45	2.30
Southern California	9.94	5.80
Total Federal OCS	18.21	10.49
Pacific State Waters**	1.00	0.95
TOTAL	19.21	11.44

* Estimates provided by the U.S. Mineral Management Service based on the 2003 National Assessment. No breakdown by Planning Area was provided.

**Based on estimates provided by the California State Lands Commission.

Pacific Coast



Great Lakes

At present, Michigan is the only state in the United States that has leased oil and gas rights under the Great Lakes. None of the states bordering the Great Lakes allow offshore rigs in the water, but 13 wells have been drilled directionally from the Michigan coastline of Lake Erie. In April 2002 the Michigan Legislature passed a statute that permanently bans directional drilling beneath the Great Lakes and prohibits the state from issuing any lease that would allow such drilling. More than 2,000 wells have been drilled under Lake Erie from Canada.

FEDERAL - GREAT LAKES REGION

In 2001, Congress issued a two-year moratorium on Great Lakes drilling, citing environmental concerns. This ban prevented state and federal agencies from issuing leases or permits for new drilling, either directional or offshore, in or under the Great Lakes through September 30, 2003. The ban was subsequently extended through 2007.

Section 503 of the Energy and Water Appropriations Act of 2002 directed the U.S. Army Corps of Engineers (the Corps) to conduct a study of the known and potential environmental effects of oil and gas drilling activity in the Great Lakes. In June 2004, the House Energy and Water Appropriations Subcommittee requested that the Corps initiate this study, which Congress intended to use to help inform its decision regarding whether to further extend the moratorium.

STATE - GREAT LAKES REGION

In 1987, the Michigan Environmental Science Board (MESB) issued a report on the subject of directional oil drilling under the Great Lakes. The MESB reported that directionally drilling a well under the lake poses very little risk of leaking pollution into the water, but rather the risk of potential environmental impact exists on land at the location of the well-head and associated pipelines. The state of Michigan suspended all new lease sales until the state could implement the MESB recommendations. Some controversy has been associated with the interpretation and implementation of the MESB recommendations.

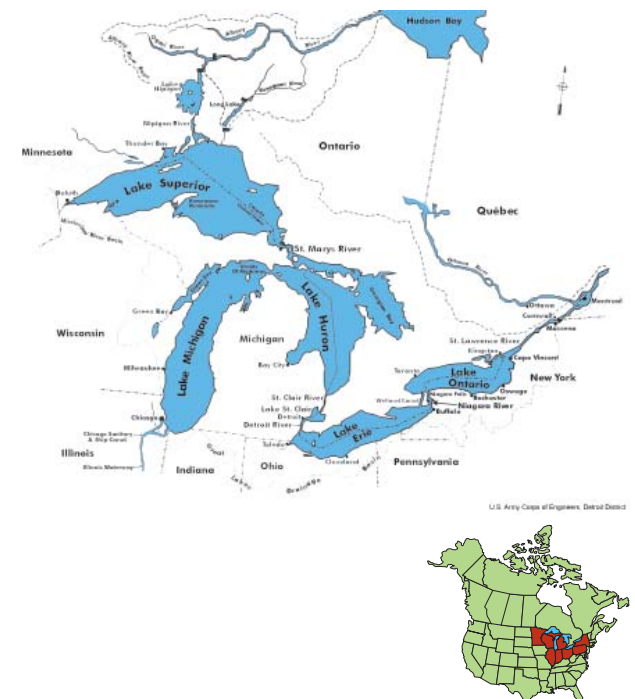
In 1985, the eight governors of Great Lakes states signed a non-binding compact agreeing to ban oil drilling in the waters of the Great Lakes, but this statement did not specifically address directional drilling. States having reconsidered the issue have taken the position that the governors' compact applies only to offshore drilling and not directional drilling from land.

Section 386 of the Energy Policy Act enacted in August 2005 now prohibits the issuance of any new state or federal lease in the Great Lakes for oil and gas drilling, whether from offshore or from onshore directional wells.

RESOURCES UNDER MORATORIA

For purposes of this study, potential resource estimates underlying the Great Lakes were determined to range from 30 million to 500 million barrels of oil (a mid-range estimate of 270 million barrels was assumed) and about 4 Tcf of natural gas.

Great Lakes

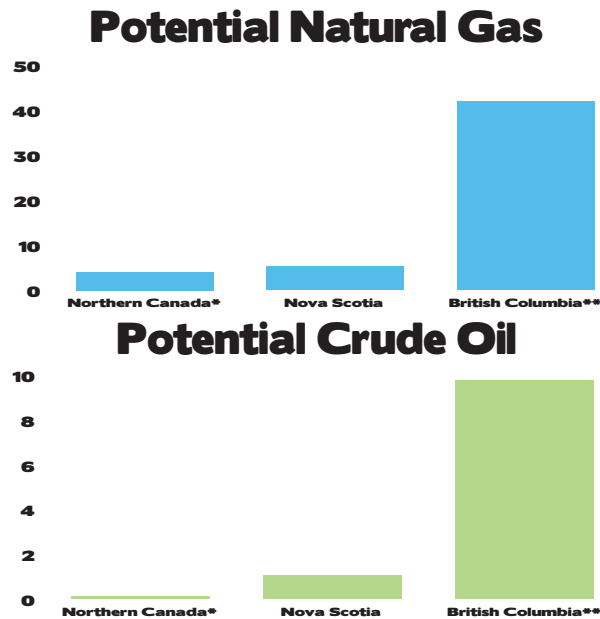


Canada Overview

The mean estimate of the undiscovered natural gas underlying Canadian moratorium areas is 51 Tcf, and mean undiscovered crude oil is estimated to be 11 billion barrels.** However, the size of Canada's offshore natural gas resource base is a major uncertainty, particularly for those frontier areas under moratoria, since they are based on a limited amount of geological data.

Moreover, some of the moratorium areas within Canada exist within various parts of larger assessment areas; and the potential resources under these areas have not been separately assessed.

Finally, the estimates reflect information taken from existing publications that date back several years.



Offshore Canada

Estimate of Undiscovered Crude Oil
and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
Northern Canada*	4.00	0.10
Nova Scotia	5.30	1.06
British Columbia**	41.80	9.80
TOTAL	51.10	10.96

* Estimates are based on internal studies performed in 2004-2005 by the Northern Oil and Gas Directorate, Canadian Federal Department of Indian Affairs and Northern Development. Lancaster Basin was formally under moratorium, but it remains a very environmentally sensitive area.

** Estimates for British Columbia are total median in-place resources.

Northern Canada

The management of oil and gas resources north of 60 degrees latitude in the Northwest Territories, Nunavut, and northern offshore is a federal responsibility, carried out by the Northern Oil and Gas Directorate of the Department of Indian Affairs and Northern Development. Prior to devolution in 1998, management of Yukon oil and gas was also a federal responsibility.

Petroleum resource management on Crown lands north of 60 degrees latitude is exercised under two federal statutes: the Canada Petroleum Resources Act (CPRA) and the Canada Oil and Gas Operations Act (COGOA). The CPRA governs the allocation of Crown lands to the private sector, tenure to the allocated rights and the setting and collection of royalties. The Minister of Indian Affairs and Northern Development administers the act. The COGOA regulates the industrial activities with respect to resource conservation, environmental protection and safety of workers. The National Energy Board administers the act.

Oil and gas activity in the north has a long history extending back to the discovery of the Norman Wells Oil Field in 1919. Exploration rights issued throughout the

1960s and 1970s covered almost all of the prospective sedimentary basins in the north. In the 1970s, the government instituted a freeze on the issuance of new exploration rights in order to facilitate the aboriginal land claims process in general, and the accompanying land selection process in particular.

At the time, it was not anticipated that the lands claim process would take so long to conclude. Two decades passed before the signing of many land claims settlements. In the intervening years, almost all historical exploration licenses had lapsed. The rights issuance process was re-introduced after the settlement of lands claims in the Beaufort-Mackenzie Basin in 1989, in the High Arctic in 1991 and in the mainland Northwest Territories in 1994.

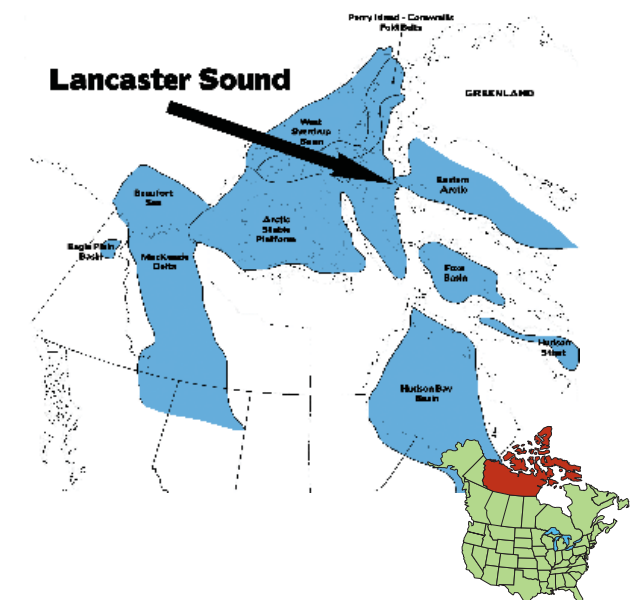
In 1976 exploration activity in the Lancaster Basin area of the Eastern Arctic was suspended so that comprehensive environmental assessment work could be preformed. In 1998, pre-1976 exploration permits were converted to exploration licenses, which are scheduled to expire in 2007. To date there has been no oil and gas activity in the licensed areas, despite significant poten-

tial. The Lancaster Basin remains a very environmentally sensitive area.

RESOURCES FORMERLY UNDER MORATORIA

The ultimate hydrocarbon resources (discovered and undiscovered) of Northern Canada's offshore areas are estimated to be approximately 10 billion barrels of oil and 190 Tcf of gas. The reported resources do not break out that portion of the ultimate resources that may be found in onshore portions of these predominantly offshore basins. The ultimate potential of the Lancaster Basin is believed to be approximately 100 million barrels of oil and 4 Tcf of natural gas.¹⁷

Northern Canada



¹⁷ The source of the estimates found in this section is from internal studies performed in 2004/05 by the Northern Oil and Gas Directorate, Canadian Federal Department of Indian Affairs and Northern Development.

Nova Scotia

Georges Bank is a shallow, submarine bank located on the OCS about 150 kilometers southwest of Cape Sable, Nova Scotia. It is bound on the north by the Gulf of Maine, on the northeast by the Northeast Channel which separates it from Brown's Bank, and on the southwest by the Great South Channel, which lies between the bank and Nantucket Shoals.

In 1964, the Canadian government issued the first petroleum exploration permit in the Georges Bank area. In 1969, the United States informed Canada that it too was claiming territorial rights on Georges Bank. The Canada-U.S. boundary was eventually submitted to the international court at The Hague, and was settled in 1984. The decision gave Canada jurisdiction over the northeast portion of the bank.

In 1986, local fishing interests and residents opposed any petroleum exploration activity in the bank area. In response to their concerns, the governments put a moratorium in effect.

Both the federal and provincial levels of government enacted the Canada-Nova Scotia Accord Acts in 1988. This legislation placed a moratorium on petroleum activities on Georges Bank until January 2000. The legislation also required a public review be conducted and the ministers were required to make a decision on the future of the moratorium by January 2000.

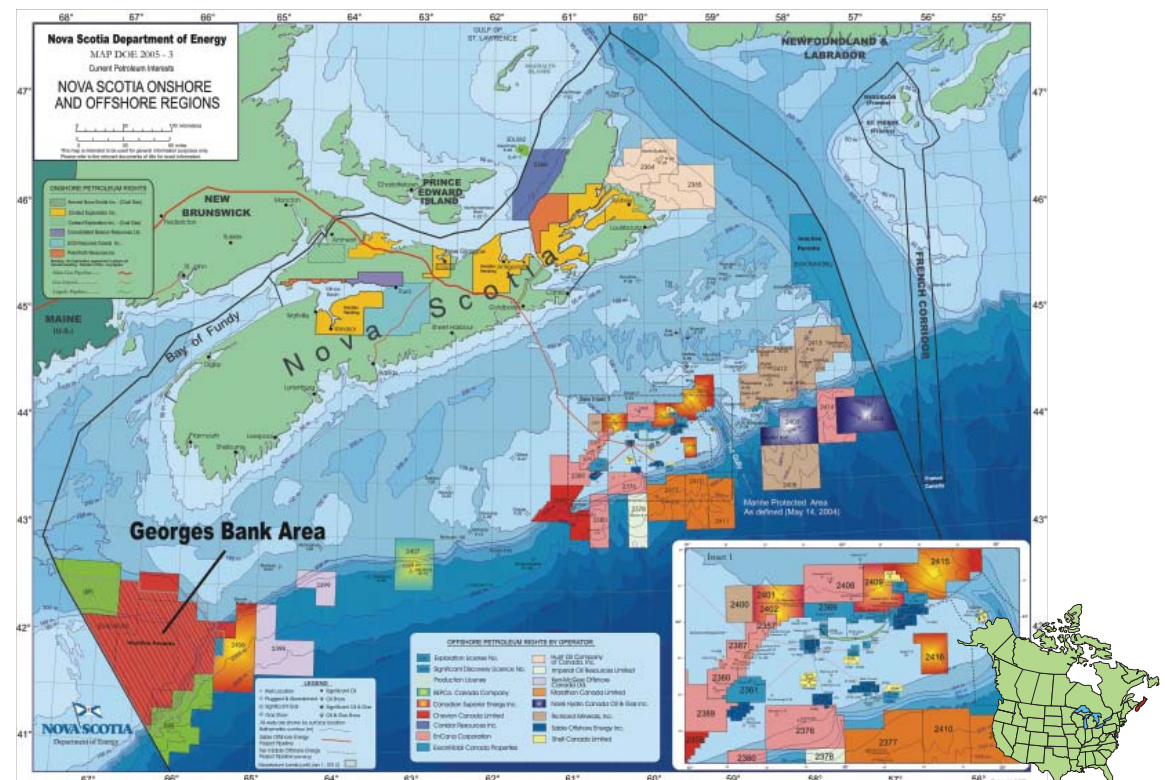
A Canadian public review of activity on Georges Bank conducted in 1999 ended in a decision to extend the moratorium until 2012, which corresponds to the expiry on the U.S. side.

RESOURCES UNDER MORATORIUM

Based on seismic surveys, the Geological Survey of

Canada estimates there is potential for 1.06 billion barrels of oil and 5.3 Tcf of natural gas in the Georges Bank area.

Nova Scotia Onshore and Offshore Regions



British Columbia

Offshore British Columbia contains four basins: Queen Charlotte Basin, Winona Basin, Tofino Basin and the Georgia Basin. The seabed of the Georgia Basin is owned by British Columbia, while the seabed of the Winona and Tofino Basins is owned by Canada. The ownership of the Queen Charlotte Basin is disputed by British Columbia and Canada. Several aboriginal groups have made claims of aboriginal rights and title to various parts of these basins.

There was extensive permitting and seismic activity off the West Coast of British Columbia in the 1950s and 1960s. The major phase of offshore exploration in the Queen Charlotte and Tofino Basins was carried out by Shell Canada Resources from 1963 to 1969. Over 32,000 kilometers of seismic were shot, and 14 wells were drilled. None of the wells indicated the presence of commercial quantities of oil or natural gas. The Geological Survey of Canada also conducted a major geological study of the Queen Charlotte Basin in the 1980s that included over 1,000 kilometers of additional seismic.

Offshore activity was halted in 1972 as part of a federal moratorium to restrict Alaskan oil tanker traffic from the inside passage off the coast of British Columbia. In the 1980s, Canada and British Columbia conducted a joint environmental assessment (EA) on a proposed exploration program. In 1986, the EA panel recom-

mended approval of the exploration program, subject to a significant number of recommendations. At the same time, Canada and British Columbia started negotiations on a “Pacific Accord” (similar to those in Atlantic Canada) to establish an offshore regulatory system for the West Coast. The negotiations ended in 1989 without agreement. Following the Exxon Valdez and Nestucca oil spills in late 1988 and early 1989, British Columbia implemented a moratorium on offshore drilling activity. The federal government then announced that it would not consider any offshore development until so requested by British Columbia.

In 2001, British Columbia appointed an independent scientific panel to review and make recommendations with respect to the moratorium on offshore activity. The panel reported that, among other things, “there is no inherent or fundamental inadequacy of the science or technology, properly applied in an appropriate regulatory framework, to justify a blanket moratorium” on offshore activities. The science panel also identified a number of science gaps that needed to be addressed. The review of offshore development technologies found that “the evidence from a relatively extensive review of conditions off British Columbia in comparison to other oil and gas areas worldwide and the latest engineering technology that applies to development indicates that there are no unique fatal flaw issues that would rule out exploration and development activities.” In 2001, Brit-

ish Columbia also appointed an Offshore Oil and Gas Task Force composed of elected members of the Government of British Columbia to visit northern coastal communities and report on the views of communities, local residents and First Nations. The task force concluded that Northern communities, including First Nations, want to have a strong voice in the contemplation of offshore oil and gas and made a number of recommendations for further work that needs to be done before any activity begins. Subsequently, British Columbia asked Canada to review its position on its moratorium on offshore activity.

In 2003, Canada announced that it would take a three-pronged approach to its review of the moratorium, namely a scientific review, a public review process, and a First Nations engagement process.

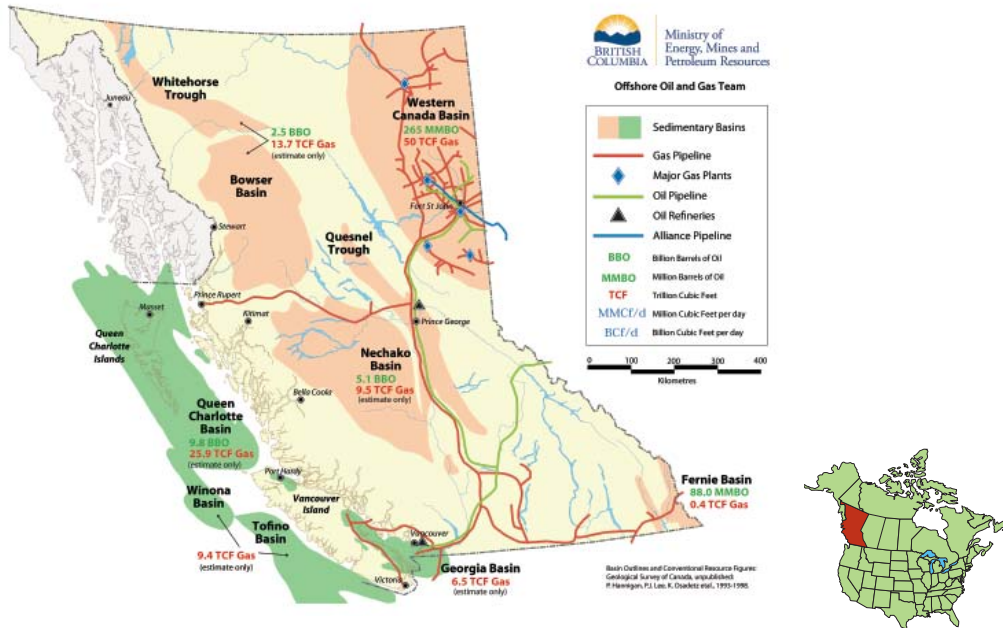
The Royal Society of Canada appointed an expert panel to carry out the science review. The panel identified a number of science gaps and made various recommendations. The panel concluded that “provided an adequate regulatory regime is in place, there are no science gaps that need to be filled before lifting the moratoria on oil and gas development.” The public review panel held public hearings in a number of communities/cities on the West Coast of British Columbia. The public review reported on what it had heard; there was no analysis of the views put before the panel. A significant

majority of those who participated in the process were opposed to lifting the moratorium, but the panel gave equal weight to an oral submission from government or a business or environmental group as to a person who signed a sheet supporting or opposing the lifting of the moratorium. The panel concluded that “the strongly held and vigorously polarized views it received do not provide a ready basis for any kind of public policy compromise at this time in regard to keeping or lifting the moratorium.” The panel set out four options for the government of Canada (from keeping the moratorium to lifting it), but made no specific recommendations on those options.

The First Nations Engagement Process involved numerous First Nations of the Northwest Coast, other coastal communities and inland communities. The process found that all participating First Nations indicated that it was not in the best interests of their people to lift the moratorium on oil and gas exploration in the Queen Charlotte Basin. A small number also added the qualifier, “it should not be lifted at this time.” However, some First Nations did indicate that they were prepared to “more fully explore the issue of offshore oil and gas exploration, provided that they were adequately resourced and given enough time to do so.”

As of the date of this report, the federal government is still reviewing its position on the moratorium.

British Columbia Onshore and Offshore Basins



British Columbia*

Estimate of Undiscovered Total Median In-Place Crude Oil and Natural Gas Resources in Moratorium Areas

	Gas (Tcf)	Oil (Bbbls)
Queen Charlotte	25.90	9.80
Georgia Basin	9.40	-
Tofino/Winona Basin	6.50	-
TOTAL	41.80	9.80

* Source: Geological Survey of Canada, Bulletin 564, 2001

RESOURCES UNDER MORATORIA

The Geological Survey of Canada published a quantitative assessment of the hydrocarbon potential of the basins off the British Columbia coast in 2001. Total median estimates of resources in place of 41.8 Tcf of natural gas and 9.8 billion barrels of oil were reported.

Appendix A: Survey Table

North American Moratoria Survey					
	Moratorium Established	Current Expiry Date	Description of Area	Extent of Area	Technically Recoverable Resources
United States					
Alaska	1989; extended in 1998	2012	North Aleutian Basin Katchemak Bay	52,234 sq. miles 150 sq. miles	6.2 Tcf (gas) 0.5 million bbls (oil)
Pacific Coast	1998	2012	Washington-Oregon Northern California Central California Southern California	NI*	19.2 Tcf (gas) 11.4 billion bbls (oil)
Gulf of Mexico	1998	2012	Alabama Florida	76 million acres	20.7 Tcf (gas) 3.6 billions bbls (oil)
Atlantic Coast	1998	2012	North Atlantic Mid Atlantic South Atlantic Strait of Florida	245.2 million acres	33.3 Tcf (gas) 3.5 billion bbls (oil)
Great Lakes	2001	Extended indefinitely by the Energy Policy Act of 2005	Lake Erie Lake Huron Lake Michigan Lake Ontario Lake Superior	38,500 sq. miles	4.0 Tcf (gas) 30-500 million bbls (oil)

North American Moratoria Survey

	Moratorium Established	Current Expiry Date	Description of Area	Extent of Area	Technically Recoverable Resources
Canada					
Northern Canada	1978	1998 (considered to be a very environmentally sensitive area)	Lancaster Sound Basin	3.3 million acres	4.0 Tcf (gas) 100 million bbls (oil)
Nova Scotia	1999	2012	Georges Bank	7,000 sq. km	5.3 Tcf (gas) 1.06 billion bbls (oil)
British Columbia**	1972/1989	no expiry date identified	Queen Charlotte Basin Tofino Basin Georgia Basin Winona Basin	90,000 sq. km	41.8 Tcf (gas) 9.8 million bbls (oil)

NOTES:

* No Information available

** Estimates for British Columbia are median in-place resources

Appendix B: Contributors

Information and data contained in this report is derived solely through research of documentation of potential resources from a variety of publicly available reports and documents. The North American Coastal Alliance consolidated and summarized this information and data into a single document to facilitate review by other interested parties.

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About the Commission

The Interstate Oil and Gas Compact Commission is a multi-state government agency that champions conservation and efficient recovery of our nation's oil and natural gas resources while protecting health, safety and the environment.

The IOGCC consists of the governors of 37 states (30 members and seven associate states) that produce most of the oil and natural gas in the United States, as well as seven international affiliates. Chartered by Congress in 1935, the organization is the oldest and largest interstate compact in the nation.

The IOGCC assists states in balancing interests through sound regulatory practices. These interests include: maximizing domestic oil and natural gas production, minimizing the waste of irreplaceable natural resources, and protecting human and environmental health.

The IOGCC also provides an effective forum for government, industry, environmentalists and others to share information and viewpoints, allowing members to take a proactive approach to emerging technologies and environmental issues. For more information visit www.iogcc.state.ok.us or call 405.525.3556.



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January 2006



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APPENDIX

L

Marginal Wells: *fuel for economic growth*



2006 Report



About the Interstate Oil and Gas Compact Commission

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About the Oklahoma Commission on Marginally Producing Oil and Gas Wells

Special thanks to the Oklahoma Commission on Marginally Producing Oil and Gas Wells.

The Oklahoma Commission on Marginally Producing Oil and Gas Wells is an Oklahoma state agency, funded by the oil and natural gas industry, with a purpose of protecting and promoting Oklahoma production of crude oil and natural gas. The organization's purpose is to serve the operator with its technology transfer programs; to serve the state by making sure that its most vital resource is continuously produced and not prematurely abandoned; and to serve the public as an information source regarding the importance of the industry in their lives and the state in which they live. For more information, visit www.marginalwells.com.

Introduction

The information within these pages tells an exciting story about one of America's greatest treasures. Marginal, low volume wells are the model of conservation and economic development, contributing significantly to the lifestyles of all Americans.

The Interstate Oil and Gas Compact Commission has been telling the story of these wells since the beginning of World War II – a time when conservation could not have been more important. Today, they continue to be critical suppliers of the nation's energy.

Although marginal wells are not glamorous and may receive little attention, together they provide 17 percent of oil and 9 percent of natural gas produced onshore in this country. In fact, without these wells the United States would have to increase imports by nearly 7 percent to make up for the shortage.

The increase in this year's production numbers illustrates the increasing importance of these wells. Daily marginal gas production averaged its highest in 10 years. On the oil side, smaller producing states such as New York are also experiencing dramatic increases in production.



However, the wells' influence stretches far beyond the oil and gas industry. Every dollar of marginal oil and gas production creates nearly \$1.01 of economic activity. Additionally, nearly 10 jobs are dependent upon every \$1 million of marginal oil and gas produced.

Marginal wells provide American energy to Americans and stand as a testament to ingenuity and conservation. The cumulative energy provided by these tiny producers touches the lives of all Americans, providing tax revenue for states, jobs for American families and energy security.

It is our hope that the numbers from this report tell this story and explain the role marginal wells continue to play in providing for the country's bright energy future.

Marginal wells are the model of conservation and economic development, contributing significantly to the lifestyles of all Americans.

research and development

Research is key to the survival of marginal wells. Unfortunately, the small, independent producers who operate these wells oftentimes do not have the means to conduct their own research.

Federal and state governments and universities play a crucial role in research and development (R&D) for fossil energy. Without continued funding of these R&D programs, new methods for producing domestic energy will remain beyond the reach of American energy producers.

Unfortunately, just when R&D is most needed, federal funding is being reduced. This year the U.S. House and Senate Appropriations Committees eliminated the appropriation for federally funded oil and natural gas R&D through the U.S. Department of Energy's Office of Fossil Energy. Such a decision will deal a serious blow to the ability of our country, particularly the small producer, to keep pace technologically.

In addition, the strategies of major multinational oil companies direct much of their R&D dollars to resources that reward shareholders. Independent producers cannot justify large R&D expenditures, and 85 percent of wells in the United States, including most marginal wells, are drilled by those independent oil and gas companies.

Moreover, the shrinking major and multinational companies have taken a toll on consortia funding for domestic university research programs, thus reducing the number of active companies able to fund academic programs by half. The result is a continuing struggle for new funding mechanisms, which has been compounded by shrinking federal petroleum R&D funding in academia.

These factors and trends predict increasing difficulty for advancing R&D in the United States. For energy R&D, especially oil and natural gas upstream R&D directed at the nation's domestic resources, the battle will be even more difficult.

Marginal oil and natural gas wells are an often overlooked, but vitally important, segment of the domestic petroleum industry. In the years ahead, R&D funding will be critical to ensuring the producers of these wells have the tools necessary to continue supplying much-needed domestic energy to the nation.

More information about the current state of R&D can be found in the 2006 IOGCC publication "Who Will Fund America's Energy Future." To order a copy of the report, log on to www.iogcc.state.ok.us.

R&D funding is critical to ensuring the producers of marginal wells have the tools necessary to continue supplying much-needed domestic energy to the nation.

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What is Marginal Oil?

Marginal oil is produced from wells that operate on the lower edge of profitability. Generally speaking, low-volume “stripper” wells – defined by the IOGCC as those wells producing 10 barrels of oil per day or less – fall into this category. The IOGCC has monitored the status of marginal wells in the United States since the 1940s.

Why all the concern about such small-volume wells? While each individual well contributes only a small amount of oil (2.2 barrels a day, on average), there are 401,072 of these wells in the United States. Combined, these marginal wells produced more than 321 million barrels of oil in 2005.

Plugged/Abandoned Wells

Many states have programs that allow a well to temporarily stop production. These “idle” wells are not included in the abandoned well category of this report; only wells that have been permanently plugged are included in the IOGCC’s definition. Also not included in this study’s abandoned well figures are “orphaned” wells. These are wells that are not producing,



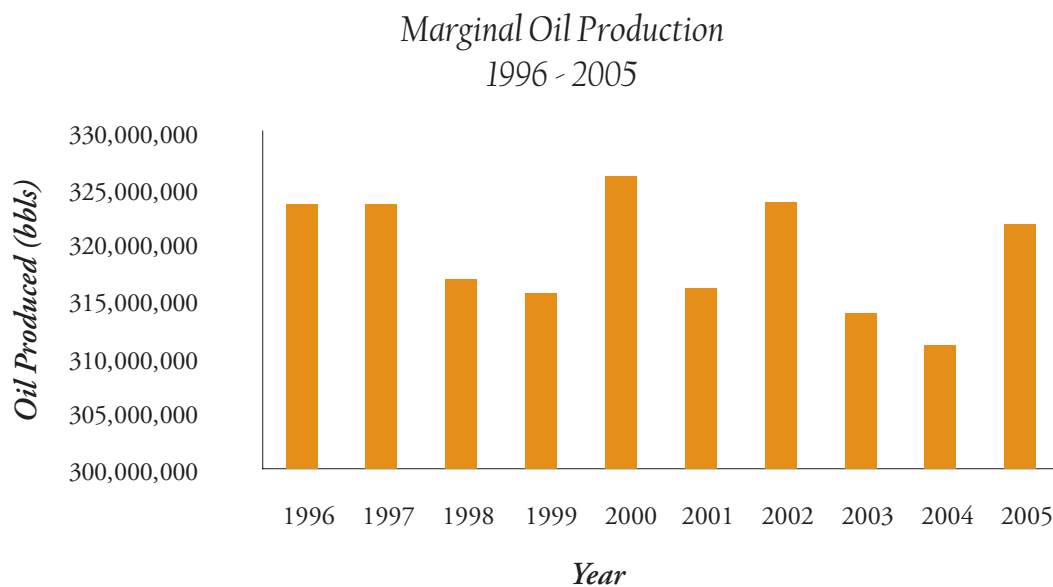
have not been plugged, and whose owners are either insolvent or cannot be located.

For more information about idled and orphaned wells, contact the IOGCC.

A marginal oil well produces 10 barrels or less of oil per day.

U.S. Marginal Oil Well Data – Past 10 Years

Year	Number of Marginal Oil Wells	Marginal Oil Production (M bbls)	Average Daily Production Per Well (bbls)	Oil Wells Plugged/ Abandoned
1996	428,842	323,468,274	2.06	16,674
1997	420,674	323,487,914	2.11	15,172
1998	406,380	316,870,286	2.14	13,912
1999	410,680	315,514,283	2.10	11,227
2000	411,629	325,947,181	2.16	10,718
2001	403,459	316,099,192	2.15	12,234
2002	402,072	323,776,606	2.21	13,635
2003	393,463	313,748,001	2.18	14,300
2004	397,362	310,922,122	2.14	11,977
2005	401,072	321,761,570	2.20	11,058



secondary recovery

The term “secondary recovery” encompasses a variety of techniques designed to increase oil recovery from an existing well. Pressure in an underground formation pushes oil upward, allowing it to be extracted. In older wells and mature fields, this

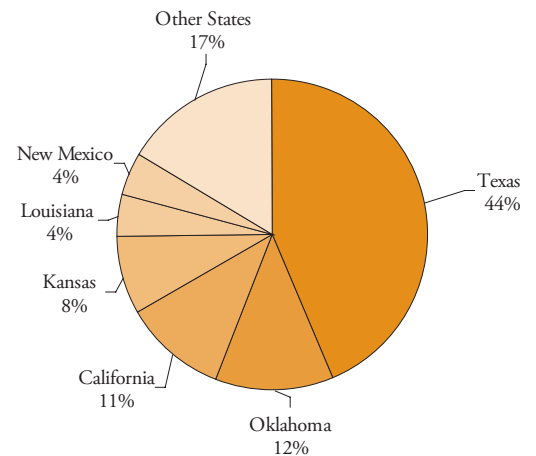
pressure has diminished over time, decreasing the flow of oil. Secondary recovery techniques permit the injection of a substance, such as water or gas, into the formation. This increases the pressure and encourages the oil to flow more easily.

Secondary Recovery of Marginal Oil as of January 1, 2006

State	Estimated Secondary Oil Produced from Marginal Wells (Mbbls)	Percent of Total Marginal Production from Secondary
Alabama	797	87.4
Arkansas	417	12.6
Colorado	997	14.2
Indiana	797	50.0
Kansas	13,825	53.5
Kentucky	1,361	69.5
Nebraska	1,031	64.5
New Mexico	5,695	40.5
New York	19	9.0
Ohio	48	1.0
Oklahoma	19,344	49.2
South Dakota	35	64.8
Utah	906	56.0
West Virginia	195	15.0

u.s. state rankings

	Number of Marginal Oil Wells	Production from Marginal Oil Wells (bbls)	Oil Wells Plugged and Abandoned	Average Daily Production per Well
1	Texas	Texas	Texas	South Dakota
2	Oklahoma	Oklahoma	California	Arizona
3	Kansas	California	Kansas	North Dakota
4	Ohio	Kansas	Oklahoma	Utah
5	California	Louisiana	Louisiana	Alabama
6	Louisiana	New Mexico	Illinois	California
7	Kentucky	Illinois	New Mexico	Michigan
8	Pennsylvania	Wyoming	Ohio	Colorado
9	Illinois	Colorado	Wyoming	Texas
10	New Mexico	Ohio	Kentucky	Nebraska
11	Wyoming	Pennsylvania	Pennsylvania	New Mexico
12	West Virginia	Arkansas	Colorado	Oklahoma
13	Colorado	Michigan	New York	Arkansas
14	Indiana	North Dakota	Arkansas	Tennessee
15	Arkansas	Kentucky	Montana	Montana
16	New York	Montana	Michigan	Louisiana
17	Montana	Utah	Mississippi	Wyoming
18	Michigan	Nebraska	Utah	Kansas
19	Mississippi	Indiana	West Virginia	Illinois
20	Nebraska	West Virginia	North Dakota	Mississippi
21	North Dakota	Alabama	Indiana	Virginia
22	Utah	Mississippi	Nebraska	Indiana
23	Alabama	Tennessee	Tennessee	Pennsylvania
24	Missouri	New York	Missouri	Missouri
25	Tennessee	Missouri	Virginia	Ohio
26	South Dakota	South Dakota	South Dakota	West Virginia
27	Arizona	Arizona	Alabama	Kentucky
28	Virginia	Virginia	Arizona	New York



Percent of Total Marginal Oil Well Production in Survey States (bbls)

Marginal Oil Well Survey: as of

State	Number of Marginal Oil Wells	Production from Marginal Oil Wells (bbls)	Oil Wells Plugged and Abandoned	Average Daily Production Per Well
Alabama	665	911,785	1	3.76
Arizona	17	31,432	0	5.07
Arkansas	4,000	3,317,410	55	2.27
California	26,444	35,563,813	2,410	3.68
Colorado	5,982	7,001,499	105	3.21
Illinois	16,407 *	8,461,222 *	547 *	1.42
Indiana	5,364	1,594,296	22	0.81
Kansas	38,692	25,827,950	2,207	1.83
Kentucky	19,012	1,958,015	178	0.28
Louisiana	20,041	14,152,725	618 *	1.93
Michigan	2,011 *	2,657,497	52	3.62
Mississippi	1,858	895,452	40	1.32
Missouri	495	85,406	7	0.47
Montana	2,424	1,947,855	54	2.20
Nebraska	1,478	1,598,224	19	2.96
New Mexico	14,069	14,065,576	349	2.74
New York	2,553	211,292	70	0.23
North Dakota	1,416	2,217,706	25	4.29
Ohio	28,828	4,840,874	298	0.46
Oklahoma	46,798	39,318,486	1,015	2.30
Pennsylvania	16,662 *	3,652,770 *	171 *	0.60
South Dakota	27	54,169	2	5.50
Tennessee	290	235,127	15 *	2.22
Texas	124,116	139,959,142	4,722	3.09
Utah	1,163	1,618,810	37	3.81
Virginia	3	1,233	4	1.13
West Virginia	7,900	1,300,000	31	0.45
Wyoming	12,357	8,281,804	211	1.84
Totals	401,072	321,761,570	13,265	2.20

* Estimated

January 1, 2006

State	Total 2005 Oil Production (Mbbbls)	Marginal Oil Well Reserves (Mbbbls)		
		<i>Primary</i>	<i>Secondary</i>	<i>Total</i>
Alabama	5,159	995	1,035	2,030
Arizona	50	154	0	154
Arkansas	6,338	37,265	31,745	69,010
California	255,676	69,395	62,286	131,681
Colorado	22,918	17,396	13,669	31,065
Illinois	8,889 *	12,736	13,151	25,887
Indiana	1,594	8,824	8,512	17,336
Kansas	33,592	59,107	56,789	115,896
Kentucky	2,454	11,708	17,563	29,271
Louisiana	51,479	59,949	58,761	118,710
Michigan	5,448 *	13,157	9,908	23,065
Mississippi	17,917	10,861	10,026	20,887
Missouri	85	1,342	1,263	2,605
Montana	32,870	29,673	34,834	64,507
Nebraska	2,413	2,568	4,672	7,240
New Mexico	54,179	22,560	19,216	41,776
New York	211	1,205	117	1,322
North Dakota	35,672	24,361	23,500	47,861
Ohio	5,652	34,187	113	34,300
Oklahoma	60,939	86,472	93,678	180,150
Pennsylvania	3,653 *	8,483	11,715	20,198
South Dakota	1,469	180	173	353
Tennessee	327	194	135	329
Texas	346,351	495,958	532,634	1,028,592
Utah	16,658	1,618	3,141	4,759
Virginia	26	40	38	78
West Virginia	1,300 *	3,548	3,244	6,792
Wyoming	51,626	75,000	100,000	175,000
Totals	1,024,945 **	1,088,936	1,111,918	2,200,854

* *Estimated*

** *Total represents only oil production from states with stripper wells.*

COMPARE: marginal wells and

2002

2003

State	Number of Marginal Wells	Production from Marginal Wells (bbls)	Number of Marginal Wells	Production from Marginal Wells (bbls)
Alabama	639	1,054,118	632	1,152,351
Arizona	17	25,942	18	23,303
Arkansas	3,362	3,316,454	3,615	3,302,376
California	24,420	35,133,050	25,089	36,015,129
Colorado	5,384	4,646,241	5,334	5,442,974
Illinois	17,466 *	10,220,000 *	17,154 *	10,600,000 *
Indiana	4,956	2,021,618	5,049	1,864,883
Kansas	33,317	25,178,007	32,883	25,103,681
Kentucky	19,462	2,077,228	19,272	1,942,879
Louisiana	20,891	16,126,868	20,722	15,567,256
Michigan	3,428	1,849,850	2,578	2,500,500
Mississippi	442	490,784	437	604,800
Missouri	364	90,919	489	86,133
Montana	2,274	1,830,438	2,291	1,830,410
Nebraska	1,451	1,765,208	1,423	1,651,923
New Mexico	13,379	13,175,602	13,577	13,693,595
New York	2,758	183,095	2,763	152,967
North Dakota	1,384	2,110,860	1,394	2,288,191
Ohio	28,850	4,904,815	28,911	4,696,636
Oklahoma	56,673	47,070,879	48,657	43,703,475
Pennsylvania	15,470 *	2,233,000 *	15,758 *	2,466,000 *
South Dakota	22	34,574	24	51,461
Tennessee	424	241,036	385 *	270,827
Texas	124,551	129,017,097	123,402	128,058,395
Utah	1,049	1,449,051	1,051	1,418,563
Virginia	13	5,764	7	2,502
West Virginia	8,210	1,250,000	8,200	1,400,000 *
Wyoming	11,416	8,596,694	12,348	7,856,791
Totals	402,072	316,099,192	393,463	313,748,001

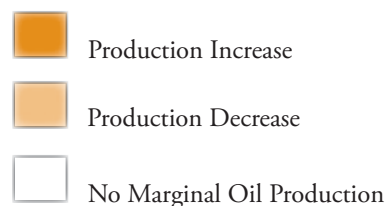
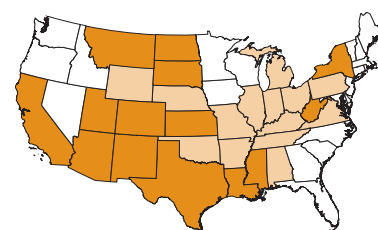
* Estimated

marginal oil production

2004

2005

State	Number of Marginal Wells	Production from Marginal Wells (bbls)	Number of Marginal Wells	Production from Marginal Wells (bbls)
Alabama	669	1,141,127	665	911,785
Arizona	17	23,746	17	31,432
Arkansas	3,948	3,620,354	4,000	3,317,410
California	25,622	34,955,831	26,444	35,563,813
Colorado	5,605	6,316,308	5,982	7,001,499
Illinois	16,751 *	10,040,292 *	16,407 *	8,461,222
Indiana	5,004	1,729,606	5,364	1,594,296
Kansas	38,363	25,493,168	38,692	25,827,950
Kentucky	19,129	2,005,480	19,012	1,958,015
Louisiana	20,576	14,136,304	20,041	14,152,725
Michigan	2,306	3,055,339	2,011 *	2,657,497
Mississippi	478	678,566	1,858	895,452
Missouri	487	88,053	495	85,406
Montana	2,335	1,879,426	2,424	1,947,855
Nebraska	1,450	1,654,195	1,478	1,598,224
New Mexico	13,882	13,990,201	14,069	14,065,576
New York	2,759	171,760	2,553	211,292
North Dakota	1,392	2,205,309	1,416	2,217,706
Ohio	28,918	4,868,915	28,828	4,840,874
Oklahoma	48,250	41,427,782	46,798	39,318,486
Pennsylvania	16,061 *	3,669,959 *	16,662 *	3,652,770
South Dakota	20	35,452	27	54,169
Tennessee	390	261,984	290	235,127
Texas	121,490	126,260,710	124,116	139,959,142
Utah	1,111	1,523,025	1,163	1,618,810
Virginia	6	1,974	3	1,233
West Virginia	8,000	1,200,000	7,900	1,300,000
Wyoming	12,343	8,487,256	12,357	8,281,804
Totals	397,362	310,922,122	401,072	321,761,570



*Marginal Oil Production
Comparison: 2004 v 2005*

* Estimated

What is Marginal Gas?

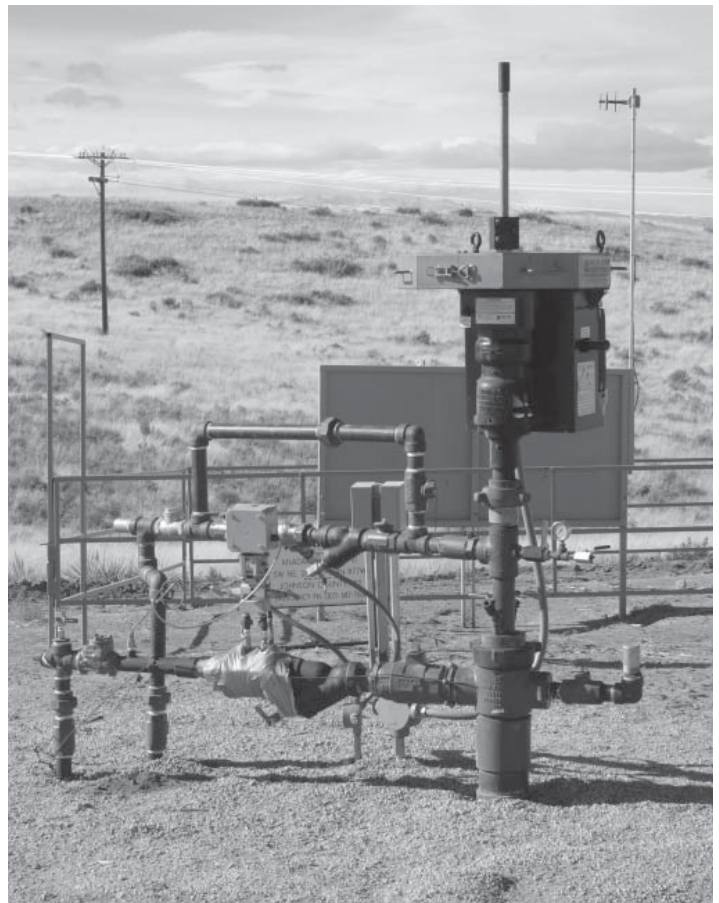
Marginal gas is natural gas produced from a well that operates on the lower edge of profitability. Generally speaking, these are low-volume “stripper” gas wells – defined by the IOGCC as a natural gas well that produces 60 thousand cubic feet (Mcf) per day or less.

Marginal gas wells represent more than 9 percent of the total natural gas produced onshore in the lower 48 states.

The table on the following page indicates the status of marginal gas production over the past 10 years.

The number of gas wells in the marginal category has steadily increased during the past decade. Total production from marginal gas wells also has steadily increased, with daily production averaging its highest in 10 years.

As with marginal oil wells, “abandoned” natural gas wells are those that have been permanently plugged. Significantly, the

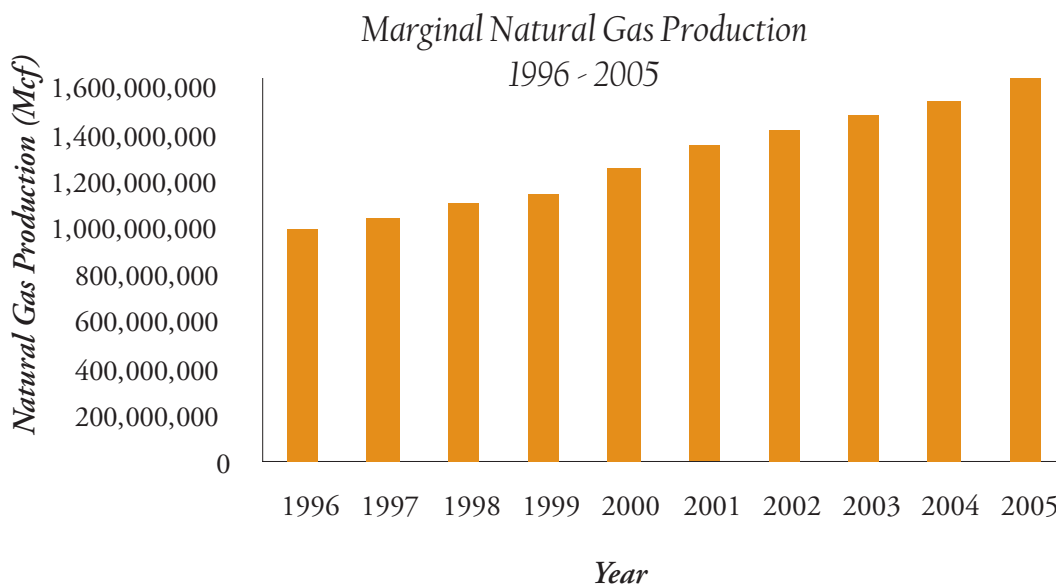


total number of pluggings in 2005 increased for the fifth consecutive year, while demand for natural gas continues to rise.

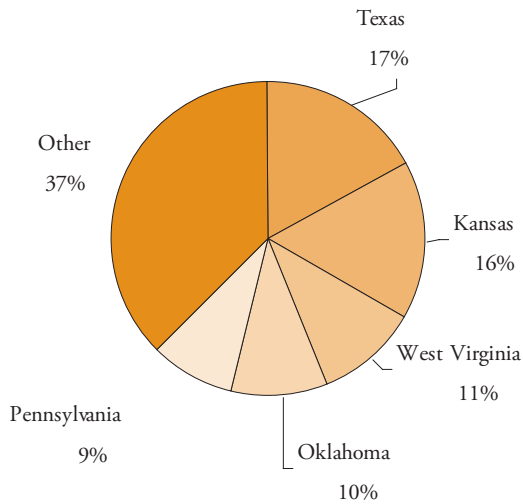
A marginal gas well produces 60 Mcf or less of natural gas per day.

U.S. Marginal Gas Well Data – Past 10 Years

Year	Number of Marginal Gas Wells	Marginal Gas Production (Mcf)	Pluggings/ Abandonments	Average Daily Production Per Well (Mcf)
1996	168,702	986,676,219	4,671	16.0
1997	189,756	1,042,153,002	4,661	15.0
1998	199,745	1,104,683,975	4,203	15.2
1999	207,766	1,138,979,506	3,546	15.3
2000	223,222	1,258,726,664	3,534	15.4
2001	234,507	1,353,516,378	3,600	15.8
2002	245,961	1,418,273,779	3,870	15.8
2003	260,563	1,478,105,524	3,883	15.5
2004	271,856	1,539,960,495	4,129	15.5
2005	288,898	1,760,063,552	4,517	16.7



u.s. state rankings



Percent of Total Marginal Gas Production in Survey States (Mcf)

	Number of Marginal Gas Wells	Production from Marginal Gas Wells (Mcf)	Total Natural Gas Production (MMcf)	Avg. Daily Production Per Well
1	Pennsylvania	Texas	Texas	Michigan
2	West Virginia	Kansas	Wyoming	Virginia
3	Texas	West Virginia	Oklahoma	Alabama
4	Ohio	Oklahoma	Colorado	Utah
5	Wyoming	Pennsylvania	New Mexico	Colorado
6	Oklahoma	New Mexico	Louisiana	Oklahoma
7	Kentucky	Wyoming	Kansas	New Mexico
8	Kansas	Colorado	Alabama	Arkansas
9	New Mexico	Kentucky	Utah	Arizona
10	Louisiana	Michigan	West Virginia	California
11	Colorado	Ohio	Arkansas	Texas
12	Michigan	Louisiana	Michigan	South Dakota
13	New York	Montana	Mississippi	Mississippi
14	Montana	Alabama	Pennsylvania	Tennessee
15	Alabama	Arkansas	Kentucky	Nebraska
16	Arkansas	Utah	Montana	Montana
17	Indiana	New York	Virginia	North Dakota
18	Utah	Mississippi	California	Maryland
19	Mississippi	California	Ohio	Kentucky
20	Illinois	Virginia	New York	West Virginia
21	California	Indiana	North Dakota	Louisiana
22	Tennessee	Tennessee	Indiana	Wyoming
23	Virginia	Nebraska	Tennessee	Pennsylvania
24	Nebraska	North Dakota	Nebraska	Ohio
25	North Dakota	South Dakota	South Dakota	Kansas
26	South Dakota	Illinois	Illinois	New York
27	Maryland	Maryland	Arizona	Indiana
28	Arizona	Arizona	Maryland	Illinois

Marginal Natural Gas Survey as of January 1, 2006

State	Number of Marginal Wells	Production from Marginal Gas Wells (Mcf)	Gas Wells Plugged and Abandoned	Avg. Daily Production Per Well (Mcf)	Total 2005 Gas Production (MMcf)
Alabama	2,620 **	26,757,739 **	18 **	28.0	318,954
Arizona	2	17,212	4	23.6	233
Arkansas	2,114	18,707,824	21	24.2	181,695
California	527	4,428,540	86	23.0	87,599
Colorado	8,861	88,788,233	101	27.5	1,509,194
Illinois	551	184,000	10	0.9	347
Indiana	2,110	3,134,583	5	4.1	3,135
Kansas	15,120	283,712,000	172	5.1	380,316
Kentucky	16,618	82,323,314	58	13.6	92,623
Louisiana	10,035	42,130,824 *	333 *	11.5	1,184,330
Maryland	7	36,468	0	14.2	36
Michigan	6,003	77,388,412	84	35.3	176,429
Mississippi	1,226	9,486,746	19	21.2	174,470
Montana	4,162	27,426,557	105	18.1	91,628
Nebraska	108	720,360	0	18.3	939
New Mexico	10,858	97,358,159	272	24.6	1,353,776
New York	5,607	9,896,329	5	4.8	54,595
North Dakota	68	401,057	3	16.2	14,543
Ohio	33,355	68,267,000	520	5.6	84,135
Oklahoma	18,706	169,439,950	392	24.8	1,605,654
Pennsylvania	46,654 *	151,651,000 *	149 *	8.9	168,501 *
South Dakota	50	399,891	0	21.9	446
Tennessee	315	2,200,000	10 *	19.1	2,200
Texas	37,396	302,083,547	1,438	22.1	5,120,528
Utah	1,419	14,429,074	36	27.9	280,296
Virginia	285	3,651,691	40 *	35.1	88,893
West Virginia	40,900	186,000,000	277	12.5	203,500 *
Wyoming	23,221	89,043,042	359	10.5	1,821,365
Totals	288,898	1,760,063,552	4,517	16.7	15,000,360 •

* Estimated

** Includes natural gas from coal seams

• This figure represents only states with marginal natural gas production; does not include production figures from states without marginal natural gas production.

COMPARE: marginal wells and

2002

2003

State	Number of Marginal Wells	Production from Marginal Wells (Mcf)	Number of Marginal Wells	Production from Marginal Wells (Mcf)
Alabama	1,696 **	18,139,406 **	1,931 **	20,885,970 **
Arizona	4	3,387	1	1,177
Arkansas	1,719	15,574,407	1,847 *	16,252,825
California	446	3,506,947	468	3,855,523
Colorado	6,701	60,945,434	7,342	73,077,507
Illinois	172	184,860	209	184,860
Indiana	1,545	1,309,120	2,291	1,464,372
Kansas	10,437	124,877,543	9,906	118,418,079
Kentucky	16,010	78,444,980	16,139	77,865,801
Louisiana	9,595	40,835,950	9,772	40,329,957 *
Maryland	6	13,446	7	34,943
Michigan	4,100	55,623,429	4,950	66,782,258
Mississippi	260	2,718,961	387	4,477,027
Montana	3,533	25,286,348	3,754	26,158,548
Nebraska	99	750,809	99	833,513
New Mexico	9,232	81,059,390	9,616	84,488,076
New York	5,442	10,637,283	5,723	11,518,289
North Dakota	55	449,971	67	762,017 **
Ohio	33,345	75,993,000	33,367	75,109,000 *
Oklahoma	17,676 **	153,207,218 **	20,321 **	178,200,970 **
Pennsylvania	40,830 *	131,800,000 *	42,437	133,455,545 *
South Dakota	56	396,482	56	415,523
Tennessee	401	1,586,127	310 *	1,411,060
Texas	32,200	258,983,600	33,312	268,891,683
Utah	929	9,359,853	1,099	11,928,457
Virginia	127	1,807,834	150	2,042,666 **
West Virginia	37,528	208,775,000 *	38,240	188,000,000 *
Wyoming	11,817 **	56,002,994 **	16,762 **	71,259,878 **
Totals	245,961	1,418,273,779	260,563	1,478,105,524

* Estimated

** Includes natural gas from coal seams

marginal gas production

2004

2005

State	Number of Marginal Wells	Production from Marginal Wells (Mcf)	Number of Marginal Wells	Production from Marginal Wells (Mcf)
Alabama	2,194 **	22,895,790 **	2,620 **	26,757,739 **
Arizona	2	10,987	2	17,212
Arkansas	1,913 *	16,923,448	2,114	18,707,824
California	490	4,247,011	527	4,428,540
Colorado	7,780	79,619,265	8,861	88,788,233
Illinois	409	184,000	551	184,000
Indiana	2,386	3,401,445	2,110	3,134,583
Kansas	8,169	101,394,727	15,120	283,712,000
Kentucky	16,495	83,777,212	16,618	82,323,314
Louisiana	9,784	44,477,263 *	10,035	42,130,824 *
Maryland	7	33,391	7	36,468
Michigan	5,396	70,864,267	6,003	77,388,412
Mississippi	548	6,345,386	1,226	9,486,746
Montana	3,926	26,484,418	4,162	27,426,557
Nebraska	102	782,502	108	720,360
New Mexico	10,142	91,910,687	10,858	97,358,159
New York	5,710	10,261,189	5,607	9,896,329
North Dakota	58	300,815	68	401,057
Ohio	33,404	72,539,000	33,355	68,267,000
Oklahoma	23,845 **	203,812,145 **	18,706 **	169,439,950 **
Pennsylvania	43,906 *	136,394,002 *	46,654 *	151,651,000 *
South Dakota	57	455,296	50	399,891
Tennessee	270	1,936,268	315	2,200,000
Texas	35,240	284,361,426	37,396	302,083,547
Utah	1,225	12,854,032	1,419	14,429,074
Virginia	228	3,050,649	285	3,651,691
West Virginia	38,500	185,000,000	40,900	186,000,000
Wyoming	19,670 **	75,643,874 **	23,221 **	89,043,042 **
Totals	271,856	1,539,960,495	288,898	1,760,063,552

* Estimated

** Includes natural gas from coal seams

ECONOMIC IMPACT

By Dan Olds, Ryder Scott Petroleum Consultant

The United States public is concerned about world oil markets in a manner reminiscent of the oil embargo of the 1970s. The cost of gasoline and natural gas for home heating are constant reminders of how our economy is dependent on hydrocarbon fuels to make our lifestyle possible. Further, there are concerns regarding our future energy security. More people are becoming aware of how the United States competes for oil supplies in a world market against countries such as China and India, where demand continues to rise.

The United States is dependent on imports from foreign countries, and some of those countries aren't friendly or are having oil problems of their own. Historically, the United States has received a large portion of its oil imports from Venezuela, but their president has made it clear that, for political reasons, he'd like to sell that oil to someone else. Mexico is another big source of our oil imports, but there are concerns that their largest offshore fields are declining at a rapid rate. Bolivia is not a factor for U.S. oil imports but their government has effectively nationalized the oil and gas industry. Russia continues to move in a direction that may effectively accomplish the same thing. Although not a significant producer, Chad is not satisfied with the contracts they made to attract oil companies to their country; now they want to re-negotiate the deal. Iran does not export oil to the United States but their actions are impacting the world oil market. Closer to home, production from Alaska's North Slope has been cut drastically while repairs are being made to aging infrastructure.

Last year's hurricane damage to facilities in the Gulf of Mexico is still being repaired.

This type of political uncertainty, the disruptions to infrastructure and continued strong demand have all combined to drive oil prices, and hence gasoline prices, to record levels. Economists may argue that the prices have not kept pace with inflation and that in real terms, prices were higher back in the 1970s. But regardless of whether the price of gasoline is considered in real dollars or nominal dollars, the fact remains that \$50 will not fill up the tank of most cars, and \$50 is still a lot of money to most people.

Oil is not the only issue. The United States has long been producing more natural gas than oil. While oil is primarily a transportation fuel, natural gas provides a lot of home heat and electricity. The high cost of natural gas has greatly increased winter heating bills in some parts of the country. In electric generation markets, natural gas is used for peak demand, since gas fired generators can be brought on line quickly to meet demands from air conditioning on hot days. Summertime electricity brownouts and high gasoline prices have reminded people not to take the conveniences of modern life for granted.

The United States imported 72 percent of its crude oil needs in 2005 – over 13 million barrels per day. Imports have been steadily rising for years and the recent high

prices haven't seemed to change this trend. There are no near-term solutions to this dependence on imported crude, so it is important that we preserve and encourage the domestic production that we have.

Domestic oil production is about 5.1 million barrels per day. Of that, production from low rate wells, termed marginal wells, is more than 881 thousand barrels per day, accounting for more than 17 percent of domestic oil production. Using 2005's average wellhead oil price of \$50.26 per barrel, that is \$16 billion that was not spent on imports.

The United States also imports natural gas, although not nearly at the volume of crude oil. However, like oil, natural gas imports are rising and forecasts for continued strong demand dictate that the level of imports will continue to rise.

Historically, imports of natural gas were limited to volumes transported by pipeline from Canada and Mexico with small amounts arriving in tankers as liquefied natural gas (LNG). However, there are plans for several new LNG receiving facilities in various places around the country, and it is expected that LNG will become an important part of our energy supply.

As with oil wells, there are also marginal gas wells. Natural gas production is not as mature as oil, but still marginal gas production provided about 4.8 billion cubic feet per day last year, more than 9 percent of U.S. production.

The purpose of this report is to examine the economic impact that marginal oil and gas has in the United States. Not only is this production an important part of the energy supply and energy security of the United States, but the economic impact is material. It is also significant that a significant portion of this economic activity benefits rural America. Royalties from the production go to farmers and landowners, and local labor is necessary to maintain these wells.

This report focuses on the marginal oil and gas activity in 11 survey states. The original survey states for this report were based on the top producers of oil, with Alaska excluded because although it is a top oil producing state, there is essentially no marginal production there. When marginal gas statistics became available some years ago, the same survey states were used for consistency. Economic results for these states have been extrapolated to represent the economic impact of marginal production in the entire United States.

In 2005, marginal wells produced 17 percent of domestic oil and 9 percent of natural gas.

development of findings

Using data from the IOGCC's 2006 Marginal Well Report, Table 1 shows that the 11 survey states have more than 73 percent of the 401,072 total reported marginal oil wells in the United States. These wells produced more than 89 percent of marginal oil well production. Oil wells in the survey states averaged 2.7 barrels of oil per day (BOPD), better than the overall national average of 2.2 BOPD.

In 2005, 13,265 oil wells were plugged and abandoned, which is a substantial increase over last year's total of 11,977 oil wells plugged. With oil prices at such high levels, the increase in well abandonments is unexpected. One possible explanation is that well operators are using their cash flow to cover deferred abandonment obligations.

Looking at the marginal gas wells, Table 1 shows the 11 survey states have about 44 percent of the total 288,898 marginal gas wells in the United States. The total number of marginal gas wells in the United States again increased significantly from last year by 17,042 wells, whereas the number of marginal oil wells increased by only 3,710 wells.

Our original 11 survey states were based on the largest producers of marginal oil, which excluded the Appalachian states from consideration. The Appalachian Basin accounts for about 50 percent of the marginal gas well count and nearly 29 percent of the marginal gas produced. These percentages are down slightly from last year, as operators in other states are finding it economical to maintain production in wells with higher operating costs.

In order to preserve the comparability of this report, the marginal gas wells use the same survey states as the oil wells, as any error that may be introduced is not thought to be materially significant due to the higher relative value of marginal oil to marginal gas production.

Marginal gas wells produced 1,760 billion cubic feet (Bcf) in 2005, more than 4.8 Bcf per day. Each well averaged 16.7 thousand cubic feet per day (MCFD). Of the total marginal gas wells, the same percentage as last year, 1.5 percent or 4,517 wells were plugged and abandoned in 2005. Given the higher prices for both oil and gas, and the growing maturity of gas production, the changes in marginal well counts and plugging activity are in line with expectations.

Oil wells in survey states averaged 2.7 barrels of oil per day (BOPD), better than the overall national average of 2.2 BOPD.

Table 1: Marginal Wells Cumulative Impact on U.S. Economy

1.1 Marginal Oil

State	Number of Marginal Oil Wells	2005 Production from Marginal Wells (Bbls.)	2005 Abandonments	2005 Average Daily Production Per Well - BOPD
California	26,444	35,563,813	2,410	3.68
Colorado	5,982	7,001,499	105	3.21
Kansas	38,692	25,827,950	2,207	1.83
Louisiana	20,041	14,152,725	618	1.93
Mississippi	1,858	895,452	40	1.32
New Mexico	14,069	14,065,576	349	2.74
North Dakota	1,416	2,217,706	25	4.29
Oklahoma	46,798	39,318,486	1,015	2.30
Texas	124,116	139,959,142	4,722	3.09
Utah	1,163	1,618,810	37	3.81
Wyoming	12,357	8,281,804	211	1.84
<i>Subtotal</i>	<i>292,936</i>	<i>288,902,963</i>	<i>11,739</i>	<i>2.70</i>
All Others	108,136	32,858,607	1,526	0.83
Total U.S.	401,072	321,761,570	13,265	2.20

1.2 Marginal Gas

State	Number of Marginal Gas Wells	2005 Production from Marginal Wells (MCF)	2005 Abandonments	2005 Average Daily Production Per Well - MCFD
California	527	4,428,540	86	23.0
Colorado	8,861	88,788,233	101	27.5
Kansas	15,120	283,712,000	172	51.4
Louisiana	10,035	42,130,824	333	11.5
Mississippi	1,226	9,486,746	19	21.2
New Mexico	10,858	97,358,159	272	24.6
North Dakota	68	401,057	3	16.2
Oklahoma	18,706	169,439,950	392	24.8
Texas	37,396	302,083,547	1,438	22.1
Utah	1,419	14,429,074	36	27.9
Wyoming	23,221	89,043,042	359	10.5
<i>Subtotal</i>	<i>127,437</i>	<i>1,101,301,172</i>	<i>3,211</i>	<i>23.7</i>
All Others	161,461	658,762,380	1,306	11.2
Total U.S.	288,898	1,760,063,552	4,517	16.7

1.3 Marginal Oil & Gas

	Number of Marginal Wells	2005 Abandonments
<i>Subtotal</i>	<i>420,373</i>	<i>14,950</i>
All Others	269,597	2,832
Total U.S.	689,970	17,782

wellhead prices

Wellhead prices shown in Table 2 are derived from data gathered directly from the various state agencies and the U.S. Department of Energy's Energy Information Administration (EIA).

These statistics show the weighted average wellhead price was \$51.14 per barrel of oil, versus 2004's average of \$37.83 per barrel. The average price for gas was \$7.51 per Mcf, versus 2004's average of \$5.41 per Mcf.

In this year's report, state-by-state wellhead oil prices were available from the EIA, but not for natural gas.

Estimates for state gas prices were determined using the ratio of state to national prices observed from the EIA's 2004 data and applied to the EIA's 2005 nationwide wellhead gas price estimate of \$7.51.

Production from Alaska and Federal Offshore areas (OCS) were excluded from the analysis since there is essentially no marginal production from these areas and the large volume of their production tends to skew the data. This accounts for the difference in total U.S. price as shown in this report, \$7.44, and the EIA nationwide wellhead price.

Table 2: 2005 Wellhead Prices

State	Total Oil Value \$ x 1,000	Total Oil Production BBL x 1,000	Weighted Average Wellhead \$/BBL	Total Gas Value \$ x 1,000	Total Gas Production MCF x 1,000	Weighted Average Wellhead \$/MCF
California	\$10,826,658	229,963	\$47.08	\$2,445,680	319,620	\$7.65
Colorado	\$1,127,156	20,117	\$56.03	\$7,748,235	1,098,115	\$7.06
Kansas	\$1,796,445	33,635	\$53.41	\$2,444,367	365,361	\$6.69
Louisiana	\$3,935,355	72,823	\$54.04	\$10,456,608	1,295,470	\$8.07
Mississippi	\$868,443	17,516	\$49.58	\$1,228,454	155,587	\$7.90
New Mexico	\$3,202,263	60,603	\$52.84	\$10,828,185	1,608,726	\$6.73
North Dakota	\$1,819,891	34,744	\$52.38	\$405,609	52,268	\$7.76
Oklahoma	\$3,352,247	61,543	\$54.47	\$12,549,526	1,678,692	\$7.48
Texas	\$20,250,872	385,144	\$52.58	\$41,324,951	5,233,914	\$7.90
Utah	\$855,691	15,852	\$53.98	\$2,140,318	301,599	\$7.10
Wyoming	\$2,322,567	50,900	\$45.63	\$11,062,807	1,646,897	\$6.72
<i>Subtotal</i>	<i>\$50,357,587</i>	<i>982,840</i>	<i>\$51.24</i>	<i>\$102,634,740</i>	<i>13,756,249</i>	<i>\$7.46</i>
All Others	\$4,297,298	85,992	\$49.97	\$4,713,784	667,248	\$7.06
Total U.S. *	\$54,654,885	1,068,832	\$51.14	\$107,348,524	14,423,497	\$7.44

* Excludes Alaska and Federal Offshore production.

effects of abandonment

The values from Tables 1 and 2, Tables 3A and 3B show the gross value associated with marginal wells. Assuming the average marginal well producing rates for each state, Table 3A shows the oil and gas wells plugged and abandoned in the survey states during 2005 would have produced oil and gas valued at \$810.5 million. The total value of oil and gas lost due to abandonments during 2005 for all states was \$883.4 million.

It should be noted that, by attributing the average production rates of existing wells to abandoned wells, the actual productivity of abandoned wells may be slightly overstated. While no data was found to estimate the average production rates at the time of abandonment, the IOGCC and U.S. DOE estimate the range is between one and two BOPD, and the equivalent rate of 10 to 20 MCFD is assumed for gas wells.

To illustrate the overall economic impact on the U.S. economy, Table 3B assumes the abandonment of all marginal wells. This shows a theoretical loss value of \$23 billion for the survey states or \$29.5 billion for the total United States in 2005.

If the marginal oil and gas production represented in Table 3B were indeed lost to the United States, this would represent more than 8.8 million barrels of oil and 4.8 Bcf of gas each day. Using the weighted average wellhead prices for marginal production, the daily amount that would have to be spent on imports would be \$81 million.

In 2005, American Petroleum Institute (API) statistics show that we imported 4.8 billion barrels of crude oil and products. If the oil production from marginal wells active in 2005 did not exist, imports would have increased 6.7 percent to make up for the shortage. EIA statistics show that 2005's total marketed gas production was 19,145 Bcf. (Note: this figure includes federal offshore gas production.)

Marginal gas wells contributed 9.2 percent of the total production. EIA statistics also show the total of 2005 natural gas imports was 4,326 Bcf, an amount equal to 22.6 percent of natural gas production. If marginal gas wells did not exist, imports to make up the shortage would bring the level up to 31.8 percent of production.

If oil production from marginal wells active in 2005 did not exist, imports would have increased 6.7 percent to make up for the shortage.

Table 3A: Effect of 2005 Abandonments

3 A.1: Oil

\$

In 2005, the United States lost more than \$883 million in revenue from marginal wells left abandoned.

State	Number of Marginal Wells	Production From Marginal Wells (Bbls.)	Wells Abandoned	Average Daily Production Per Well - BOPD
California	26,444	35,563,813	2,410	3.68
Colorado	5,982	7,001,499	105	3.21
Kansas	38,692	25,827,950	2,207	1.83
Louisiana	20,041	14,152,725	618	1.93
Mississippi	1,858	895,452	40	1.32
New Mexico	14,069	14,065,576	349	2.74
North Dakota	1,416	2,217,706	25	4.29
Oklahoma	46,798	39,318,486	1,015	2.30
Texas	124,116	139,959,142	4,722	3.09
Utah	1,163	1,618,810	37	3.81
Wyoming	12,357	8,281,804	211	1.84
Subtotal	292,936	288,902,963	11,739	2.70
All Others	108,136	32,858,607	1,526	0.83
Total U.S. *	401,072	321,761,570	13,265	2.20

State	Lost Annual Production BBLS	2005 Average \$/BBL	2005 Lost Gross Revenue
California	3,241,143	\$47.08	\$152,593,019
Colorado	122,895	\$56.03	\$6,885,802
Kansas	1,473,232	\$53.41	\$78,685,312
Louisiana	436,425	\$54.04	\$23,584,382
Mississippi	19,278	\$49.58	\$955,791
New Mexico	348,915	\$52.84	\$18,436,672
North Dakota	39,154	\$52.38	\$2,050,908
Oklahoma	852,777	\$54.47	\$46,450,769
Texas	5,324,753	\$52.58	\$279,975,523
Utah	51,501	\$53.98	\$2,780,038
Wyoming	141,415	\$45.63	\$6,452,750
Subtotal	12,051,488	\$51.24	\$617,479,803
All Others	604,053	\$49.97	\$30,186,498
Total U.S. *	12,655,541	\$51.14	\$647,143,004

3 A.2: Natural Gas

State	Number of Marginal Wells	Production From Marginal Wells (MCF)	Wells Abandoned	Average Daily Production Per Well - MCFD
California	527	4,428,540	86	23.02
Colorado	8,861	88,788,233	101	27.45
Kansas	15,120	283,712,000	172	51.41
Louisiana	10,035	42,130,824	333	11.50
Mississippi	1,226	9,486,746	19	21.20
New Mexico	10,858	97,358,159	272	24.57
North Dakota	68	401,057	3	16.16
Oklahoma	18,706	169,439,950	392	24.82
Texas	37,396	302,083,547	1,438	22.13
Utah	1,419	14,429,074	36	27.86
Wyoming	23,221	89,043,042	359	10.51
Subtotal	127,437	1,101,301,172	3,211	23.68
All Others	161,461	658,762,380	1,306	11.18
Total U.S. *	288,898	1,760,063,552	4,517	16.69

State	Lost Annual Production MCF	2005 Average \$/MCF	2005 Lost Gross Revenue
California	722,684	\$7.65	\$5,529,859
Colorado	1,012,032	\$7.06	\$7,140,835
Kansas	3,227,412	\$6.69	\$21,592,281
Louisiana	1,398,063	\$8.07	\$11,284,707
Mississippi	147,021	\$7.90	\$1,160,823
New Mexico	2,438,886	\$6.73	\$16,415,912
North Dakota	17,694	\$7.76	\$137,306
Oklahoma	3,550,757	\$7.48	\$26,544,664
Texas	11,616,112	\$7.90	\$91,716,310
Utah	366,065	\$7.10	\$2,597,808
Wyoming	1,376,618	\$6.72	\$9,247,246
Subtotal	25,873,344	\$7.46	\$193,039,827
All Others	5,876,503	\$7.06	\$41,514,645
Total U.S. *	31,749,847	\$7.44	\$236,301,860

3 A.3: Oil & Gas

	Number of Marginal Wells	Wells Abandoned	2005 Lost Gross Revenue
<i>Subtotal</i>	<i>420,373</i>	<i>14,950</i>	<i>\$810,519,629</i>
All Others	269,597	2,832	\$71,701,143
Total U.S. *	689,970	17,782	\$883,444,864

* Excludes Alaska and Federal Offshore production

Table 3B: Effect of Hypothetical Abandonment of All Marginal Wells

3 B.I: Oil

\$

If all marginal wells were abandoned in 2005, the United States would have lost more than \$29.5 billion in revenue.

State	Number of Marginal Wells	Production From Marginal Wells (Bbls.)	Hypothetical Abandonments	Average Daily Production Per Well - BOPD
California	26,444	35,563,813	26,444	3.68
Colorado	5,982	7,001,499	5,982	3.21
Kansas	38,692	25,827,950	38,692	1.83
Louisiana	20,041	14,152,725	20,041	1.93
Mississippi	1,858	895,452	1,858	1.32
New Mexico	14,069	14,065,576	14,069	2.74
North Dakota	1,416	2,217,706	1,416	4.29
Oklahoma	46,798	39,318,486	46,798	2.30
Texas	124,116	139,959,142	124,116	3.09
Utah	1,163	1,618,810	1,163	3.81
Wyoming	12,357	8,281,804	12,357	1.84
Subtotal	292,936	288,902,963	292,936	2.70
All Others	108,136	32,858,607	108,136	0.83
Total U.S. *	401,072	321,761,570	401,072	2.20

State	Lost Annual Production Bbls	2005 Average \$/Bbl	Hypothetical 2005 Lost Gross Revenue
California	35,563,813	\$47.08	\$1,674,344,316
Colorado	7,001,499	\$56.03	\$392,293,989
Kansas	25,827,950	\$53.41	\$1,379,470,810
Louisiana	14,152,725	\$54.04	\$764,813,259
Mississippi	895,452	\$49.58	\$44,396,510
New Mexico	14,065,576	\$52.84	\$743,225,036
North Dakota	2,217,706	\$52.38	\$116,163,440
Oklahoma	39,318,486	\$54.47	\$2,141,677,932
Texas	139,959,142	\$52.58	\$7,359,051,686
Utah	1,618,810	\$53.98	\$87,383,364
Wyoming	8,281,804	\$45.63	\$377,898,717
Subtotal	288,902,963	\$51.24	\$14,802,466,426
All Others	32,858,607	\$49.97	\$1,642,050,659
Total U.S. *	321,761,570	\$51.14	\$16,453,326,208

3 B.2: Natural Gas

State	Number of Marginal Wells	Production From Marginal Wells (MCF)	Hypothetical Abandonments	Average Daily Production Per Well - MCFD
California	527	4,428,540	527	23.02
Colorado	8,861	88,788,233	8,861	27.45
Kansas	15,120	283,712,000	15,120	51.41
Louisiana	10,035	42,130,824	10,035	11.50
Mississippi	1,226	9,486,746	1,226	21.20
New Mexico	10,858	97,358,159	10,858	24.57
North Dakota	68	401,057	68	16.16
Oklahoma	18,706	169,439,950	18,706	24.82
Texas	37,396	302,083,547	37,396	22.13
Utah	1,419	14,429,074	1,419	27.86
Wyoming	23,221	89,043,042	23,221	10.51
Subtotal	127,437	1,101,301,172	127,437	23.68
All Others	161,461	658,762,380	161,461	11.18
Total U.S. *	288,898	1,760,063,552	288,898	16.69
States	Lost Annual Production MCF	2005 Average \$/MCF	Hypothetical 2005 Lost Gross Revenue	
California	4,428,540	\$7.65	\$33,886,462	
Colorado	88,788,233	\$7.06	\$626,484,524	
Kansas	283,712,000	\$6.69	\$1,898,112,133	
Louisiana	42,130,824	\$8.07	\$340,066,165	
Mississippi	9,486,746	\$7.90	\$74,903,660	
New Mexico	97,358,159	\$6.73	\$655,308,729	
North Dakota	401,057	\$7.76	\$3,112,275	
Oklahoma	169,439,950	\$7.48	\$1,266,695,137	
Texas	302,083,547	\$7.90	\$2,385,134,299	
Utah	14,429,074	\$7.10	\$102,396,935	
Wyoming	89,043,042	\$6.72	\$598,134,532	
Subtotal	1,101,301,172	\$7.46	\$8,216,757,301	
All Others	658,762,380	\$7.06	\$4,653,837,023	
Total U.S. *	1,760,063,552	\$7.44	\$13,099,474,008	

3 B.3: Oil & Gas

	Number of Marginal Wells	Hypothetical Abandonments	Hypothetical Gross Revenue
<i>Subtotal</i>	<i>420,373</i>	<i>420,373</i>	<i>\$23,019,223,727</i>
All Others	269,597	269,597	\$6,295,887,682
Total U.S. *	689,970	689,970	\$29,552,800,216

* Excludes Alaska and Federal Offshore production

RIMS II multipliers

Until 2003, this report was based on RIMS II multipliers provided by the Bureau of Economic Analysis (BEA) for industry number 8.0000, Crude Petroleum and Natural Gas. Since then, revised multipliers based on the BEA's 1997 national and 2001 regional accounts are used.

The RIMS II multipliers based on this updated work were first released in May 2004. The multipliers have been re-categorized to Industry 211000, Oil and Gas Extraction. A comparison of these new factors against the old shows the overall multiplication effect has on average increased for output and earnings for all of the survey states. However, the employment, while up on average, is not up for all states.

The basic implication of these changes is the economic activity generated by marginal well production has a larger impact on the U.S. economy under the revised multipliers, assuming no change in price levels. The magnitude of that impact is dependent on the prices received for the oil and gas.

The multipliers are shown in Table 4. The Final Demand Multipliers shown in the first three columns represent the total economic impact on the region relative to a change in demand of the output, which, in this case, is expressed as the value of marginal oil production.

The same oil and gas values can be used to determine the total impact on earnings and employment for the region. These final demand multipliers include output, earnings and employment not only within the crude petroleum and natural gas industry, but also from secondary interrelated industries that are impacted in the region.

Examples of these secondary sectors could be non-oil-field equipment manufacturers, local retailers and health care professionals that provide goods and services to both the oil sector and other sectors. Please refer to the Appendix for a more complete discussion about RIMS.

The direct effect multipliers shown in the fourth and fifth columns represent the total impact relative to a

Numbers from this analysis are revised multipliers based on the BEA's 1997 national and 2001 regional accounts.

direct change in household earnings or employment. They are used whenever changes in household earnings or employment are known.

As presented, they are not directly applicable for the purposes of this study. However, they represent the ratio

between the industry specific multiplier and the final demand multiplier. This relationship allows the calculation of earnings and employment multipliers for the oil and gas industry alone (sixth and seventh columns), without regard to the earnings and employment levels of any secondary industries.

Table 4: 2005 RIMS II Multipliers

State	Final Demand Multipliers			Direct Effect Multipliers		Calculated O&G Industry Multipliers	
	Output	Earnings	Employment	Earnings	Employment	Earnings	Employment
California	1.9891	0.4319	9.5	2.4103	2.7602	0.1792	3.4506
Colorado	2.0627	0.4337	8.6	2.5391	4.5789	0.1708	1.8861
Kansas	1.9466	0.3788	14.1	2.1995	2.0271	0.1722	6.9618
Louisiana	1.8321	0.3628	8.8	2.3102	3.7887	0.1570	2.3275
Mississippi	1.6049	0.3035	9.3	2.0655	2.4289	0.1469	3.8365
New Mexico	1.6563	0.3487	10.0	2.0363	2.6812	0.1712	3.7421
North Dakota	1.7441	0.3538	11.0	2.0231	2.4251	0.1749	4.5305
Oklahoma	2.0400	0.4224	11.5	2.3894	3.6824	0.1768	3.1144
Texas	2.0853	0.4334	8.4	2.4727	5.3808	0.1753	1.5675
Utah	1.8940	0.4018	11.6	2.4387	3.1276	0.1648	3.7026
Wyoming	1.7344	0.3242	7.9	1.8970	2.9567	0.1709	2.6753

U.S. economic impact

Tables 5A and 5B show the economic impact of marginal oil and gas production. Using the values determined from Table 3A and the multipliers from Table 4, Table 5A shows the 17,782 marginal oil and gas wells plugged and abandoned in 2005 resulted in a reduction of total economic output of \$1.77 billion, earnings reductions of \$368 million and lost employment of 8,604 jobs.

In 2005 the oil and gas industry alone lost \$154 million

of earnings and 2,577 jobs to the marginal well abandonments of the previous year.

Table 5B shows the economic impact of the theoretical abandonment of all marginal oil and gas wells. Economic output would decline by \$58.2 billion, earnings would decrease by \$11.9 billion, and 291,808 jobs would be lost. Within the oil and gas industry alone, \$5.08 billion of earnings and 88,855 jobs would be lost.

Table 5A: Economic Effects of 2005's Abandonments

5A.1 Oil

State	Revenue	Final	Final	Final	Overall Effects in Final Demand			Direct	Direct	Oil & Gas Industry	
	Lost From	Demand	Demand	Demand	Lost	Lost	Lost	Effect	Effect	Lost	Lost
	Abandonment	Multipliers	Multipliers	Multipliers	Output	Earnings	Employment	Multipliers	Multipliers	Earnings	Employment
	(Million \$)	Output	Earnings	Employment	(Million \$)	(Million \$)		Earnings	Employment	(Million \$)	
California	\$152.593	1.9891	0.4319	9.5	\$303.523	\$65.905	1,453	0.1792	3.4506	\$27.343	527
Colorado	\$6.886	2.0627	0.4337	8.6	\$14.203	\$2.986	59	0.1708	1.8861	\$1.176	13
Kansas	\$78.685	1.9466	0.3788	14.1	\$153.169	\$29.806	1,110	0.1722	6.9618	\$13.551	548
Louisiana	\$23.584	1.8321	0.3628	8.8	\$43.209	\$8.556	208	0.1570	2.3275	\$3.704	55
Mississippi	\$0.956	1.6049	0.3035	9.3	\$1.534	\$0.290	9	0.1469	3.8365	\$0.140	4
New Mexico	\$18.437	1.6563	0.3487	10.0	\$30.537	\$6.429	185	0.1712	3.7421	\$3.157	69
North Dakota	\$2.051	1.7441	0.3538	11.0	\$3.577	\$0.726	23	0.1749	4.5305	\$0.359	9
Oklahoma	\$46.451	2.0400	0.4224	11.5	\$94.760	\$19.621	533	0.1768	3.1144	\$8.212	145
Texas	\$279.976	2.0853	0.4334	8.4	\$583.833	\$121.341	2,361	0.1753	1.5675	\$49.072	439
Utah	\$2.780	1.8940	0.4018	11.6	\$5.265	\$1.117	32	0.1648	3.7026	\$0.458	10
Wyoming	\$6.453	1.7344	0.3242	7.9	\$11.192	\$2.092	51	0.1709	2.6753	\$1.103	17
<i>Subtotal</i>	<i>\$617.480</i>	<i>2.0159</i>	<i>0.4192</i>	<i>9.8</i>	<i>\$1,244.801</i>	<i>\$258.869</i>	<i>6,025</i>	<i>0.1754</i>	<i>2.9700</i>	<i>\$108.275</i>	<i>1,835</i>
All Others*	\$30.187	2.0159	0.4192	9.8	\$60.853	\$12.654	296	0.1754	2.9700	\$5.295	90
Total	\$647.143	2.0176	0.4196	9.8	\$1,305.654	\$271.524	6,321	0.1755	2.9700	\$113.570	1,925

5A.2 Natural Gas

State	Revenue	Final	Final	Final	Overall Effect in Final Demand			Direct	Direct	Oil & Gas Industry	
	Lost From	Demand	Demand	Demand	Lost	Lost	Lost	Effect	Effect	Lost	Lost
	Abandonment	Multipliers	Multipliers	Multipliers	Output	Earnings	Employment	Multipliers	Multipliers	Earnings	Employment
	(Million \$)	Output	Earnings	Employment	(Million \$)	(Million \$)		Earnings	Employment	(Million \$)	
California	\$5.530	1.9891	0.4319	9.5	\$10.999	\$2.388	53	0.1792	3.4506	\$0.991	19
Colorado	\$7.141	2.0627	0.4337	8.6	\$14.729	\$3.097	62	0.1708	1.8861	\$1.220	13
Kansas	\$21.592	1.9466	0.3788	14.1	\$42.032	\$8.179	305	0.1722	6.9618	\$3.719	150
Louisiana	\$11.285	1.8321	0.3628	8.8	\$20.675	\$4.094	100	0.1570	2.3275	\$1.772	26
Mississippi	\$1.161	1.6049	0.3035	9.3	\$1.863	\$0.352	11	0.1469	3.8365	\$0.171	4
New Mexico	\$16.416	1.6563	0.3487	10.0	\$27.190	\$5.724	165	0.1712	3.7421	\$2.811	61
North Dakota	\$0.137	1.7441	0.3538	11.0	\$0.239	\$0.049	2	0.1749	4.5305	\$0.024	1
Oklahoma	\$26.545	2.0400	0.4224	11.5	\$54.151	\$11.212	304	0.1768	3.1144	\$4.693	83
Texas	\$91.716	2.0853	0.4334	8.4	\$191.256	\$39.750	774	0.1753	1.5675	\$16.075	144
Utah	\$2.598	1.8940	0.4018	11.6	\$4.920	\$1.044	30	0.1648	3.7026	\$0.428	10
Wyoming	\$9.247	1.7344	0.3242	7.9	\$16.038	\$2.998	73	0.1709	2.6753	\$1.580	25
<i>Subtotal</i>	<i>\$193.040</i>	<i>1.9897</i>	<i>0.4192</i>	<i>9.8</i>	<i>\$384.093</i>	<i>\$78.888</i>	<i>1,877</i>	<i>0.1735</i>	<i>2.7800</i>	<i>\$33.484</i>	<i>536</i>
All Others*	\$41.515	1.9897	0.4192	9.8	\$82.602	\$17.403	407	0.1735	2.7800	\$7.203	115
Total	\$236.302	1.9750	0.4196	9.8	\$466.695	\$96.291	2,284	0.1722	2.7600	\$40.686	652

5A.3 Oil & Gas

State	Revenue	Final	Final	Final	Overall Effect in Final Demand			Direct	Direct	Oil & Gas Industry	
	Lost From	Demand	Demand	Demand	Lost	Lost	Lost	Effect	Effect	Lost	Lost
	Abandonment	Multipliers	Multipliers	Multipliers	Output	Earnings	Employment	Multipliers	Multipliers	Earnings	Employment
	(Million \$)	Output	Earnings	Employment	(Million \$)	(Million \$)		Earnings	Employment	(Million \$)	
<i>Subtotal</i>	<i>\$810.520</i>	<i>2.0097</i>	<i>0.4167</i>	<i>9.8</i>	<i>\$1,628.894</i>	<i>\$337.757</i>	<i>7,902</i>	<i>0.1749</i>	<i>2.9261</i>	<i>\$141.759</i>	<i>2,372</i>
All Others *	\$71.701	2.0007	0.4192	9.8	\$143.455	\$30.057	703	0.1743	2.8600	\$12.498	205
Total	\$883.445	2.0062	0.4163	9.7	\$1,772.349	\$367.814	8,604	0.1746	2.9167	\$154.256	2,577

*Weighted averages used for RIMS II Multipliers; excludes Alaska, Federal Offshore production.

Table 5B: Economic Effect of Hypothetical Abandonment of All Marginal Wells

5B.1 Oil

State	Revenue	Final	Final	Final	Overall Effect in Final Demand			Direct	Direct	Oil & Gas Industry	
	Lost From	Demand	Demand	Demand	Lost	Lost	Lost	Effect	Effect	Lost	Lost
	Abandonment	Multipliers	Multipliers	Multipliers	Output	Earnings	Employment	Multipliers	Multipliers	Earnings	Employment
	(Million \$)	Output	Earnings	Employment	(Million \$)	(Million \$)		Earnings	Employment	(Million \$)	
California	\$1,674.344	1.9891	0.4319	9.5	\$3,330.438	\$723.149	15,947	0.1792	3.4506	\$300.025	5,777
Colorado	\$392.294	2.0627	0.4337	8.6	\$809.185	\$170.138	3,388	0.1708	1.8861	\$67.007	740
Kansas	\$1,379.471	1.9466	0.3788	14.1	\$2,685.278	\$522.544	19,468	0.1722	6.9618	\$237.574	9,604
Louisiana	\$764.813	1.8321	0.3628	8.8	\$1,401.214	\$277.474	6,744	0.1570	2.3275	\$120.108	1,780
Mississippi	\$44.397	1.6049	0.3035	9.3	\$71.252	\$13.474	414	0.1469	3.8365	\$6.524	170
New Mexico	\$743.225	1.6563	0.3487	10.0	\$1,231.004	\$259.163	7,457	0.1712	3.7421	\$127.271	2,781
North Dakota	\$116.163	1.7441	0.3538	11.0	\$202.601	\$41.099	1,276	0.1749	4.5305	\$20.315	526
Oklahoma	\$2,141.678	2.0400	0.4224	11.5	\$4,369.023	\$904.645	24,561	0.1768	3.1144	\$378.608	6,670
Texas	\$7,359.052	2.0853	0.4334	8.4	\$15,345.830	\$3,189.413	62,069	0.1753	1.5675	\$1,289.850	11,535
Utah	\$87.383	1.8940	0.4018	11.6	\$165.504	\$35.111	1,012	0.1648	3.7026	\$14.397	324
Wyoming	\$377.899	1.7344	0.3242	7.9	\$655.428	\$122.515	2,989	0.1709	2.6753	\$64.583	1,011
<i>Subtotal</i>	<i>\$14,802.466</i>	<i>2.0447</i>	<i>0.4228</i>	<i>9.8</i>	<i>\$30,266.757</i>	<i>\$6,258.724</i>	<i>145,325</i>	<i>0.1774</i>	<i>2.7600</i>	<i>\$2,626.262</i>	<i>40,919</i>
All Others *	\$1,642.051	2.0447	0.4228	9.8	\$3,357.501	\$694.259	16,092	0.1774	2.7600	\$291.300	4,532
Total	\$16,453.326	2.0436	0.4226	9.8	\$33,624.258	\$6,952.983	161,418	0.1773	2.7600	\$2,917.562	45,451

5B.2 Natural Gas

State	Revenue	Final	Final	Final	Overall Effect in Final Demand			Direct	Direct	Oil & Gas Industry	
	Lost From	Demand	Demand	Demand	Lost	Lost	Lost	Effect	Effect	Lost	Lost
	Abandonment	Multipliers	Multipliers	Multipliers	Output	Earnings	Employment	Multipliers	Multipliers	Earnings	Employment
	(Million \$)	Output	Earnings	Employment	(Million \$)	(Million \$)		Earnings	Employment	(Million \$)	
California	\$33.886	1.9891	0.4319	9.5	\$67.404	\$14.636	323	0.1792	3.4506	\$6.072	117
Colorado	\$626.485	2.0627	0.4337	8.6	\$1,292.250	\$271.706	5,410	0.1708	1.8861	\$107.009	1,182
Kansas	\$1,898.112	1.9466	0.3788	14.1	\$3,694.865	\$719.005	26,787	0.1722	6.9618	\$326.895	13,214
Louisiana	\$340.066	1.8321	0.3628	8.8	\$623.035	\$123.376	2,999	0.1570	2.3275	\$53.405	792
Mississippi	\$74.904	1.6049	0.3035	9.3	\$120.213	\$22.733	698	0.1469	3.8365	\$11.006	287
New Mexico	\$655.309	1.6563	0.3487	10.0	\$1,085.388	\$228.506	6,575	0.1712	3.7421	\$112.216	2,452
North Dakota	\$3.112	1.7441	0.3538	11.0	\$5.428	\$1.101	34	0.1749	4.5305	\$0.544	14
Oklahoma	\$1,266.695	2.0400	0.4224	11.5	\$2,584.058	\$535.052	14,527	0.1768	3.1144	\$223.927	3,945
Texas	\$2,385.134	2.0853	0.4334	8.4	\$4,973.721	\$1,033.717	20,117	0.1753	1.5675	\$418.052	3,739
Utah	\$102.397	1.8940	0.4018	11.6	\$193.940	\$41.143	1,186	0.1648	3.7026	\$16.871	379
Wyoming	\$598.135	1.7344	0.3242	7.9	\$1,037.405	\$193.915	4,731	0.1709	2.6753	\$102.222	1,600
<i>Subtotal</i>	<i>\$8,216.757</i>	<i>1.9080</i>	<i>0.3876</i>	<i>10.1</i>	<i>\$15,677.705</i>	<i>\$3,184.891</i>	<i>83,387</i>	<i>0.1677</i>	<i>3.3700</i>	<i>\$1,378.220</i>	<i>27,721</i>
All Others*	\$4,653.837	1.9080	0.3876	10.1	\$8,879.521	\$1,803.827	47,004	0.1677	3.3700	\$780.448	15,683
Total	\$13,099.474	1.8747	0.3808	10.0	\$24,557.226	\$4,988.718	130,391	0.1648	3.3100	\$2,158.668	43,404

5B.3 Oil & Gas

States	Revenue Lost From Abandonment (Million \$)	Final Demand Multipliers Output *	Final Demand Multipliers Earnings *	Final Demand Multipliers Employment *	Overall Effect in Final Demand			Direct Effect Multipliers Earnings	Direct Effect Employment	Oil & Gas Industry	
					Lost Output (Million \$)	Lost Earnings (Million \$)	Lost Employment			Lost Earnings (Million \$)	Lost Employment
Subtotal	\$23,019.224	1.9959	0.4103	9.9	\$45,944.462	\$9,443.615	228,712	0.1740	2.9818	\$4,004.482	68,640
All Others*	\$6,295.888	1.9437	0.3968	10.0	\$12,237.022	\$2,498.086	63,096	0.1702	3.2109	\$1,071.748	20,215
Total	\$29,552.800	1.9687	0.4041	9.9	\$58,181.484	\$11,941.701	291,808	0.1718	3.0067	\$5,076.230	88,855

* Weighted averages used for RIMS II Multipliers; excludes Alaska, Federal Offshore production.

Abandonment of All Marginal Wells: How would it affect you and the country?



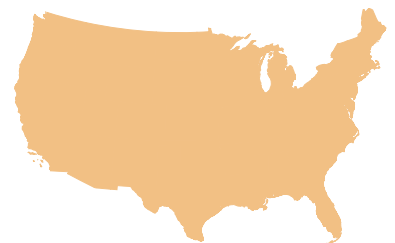
\$11.9 billion

lost in earnings



291,808

*hardworking
Americans would
lose their jobs*



\$58.2 billion

*of lost economic
output*

severance and ad valorem tax

RIMS II multipliers do not take into consideration any impact on state or local government. Therefore, the economic impact predictions do not include any payments of state or local severance taxes or any local ad valorem taxes.

Many states have reduced severance tax rates for wells that qualify for stripper or marginal status under their guidelines. For the purposes of this report, it was assumed that all of the marginal production reported for a

given state would qualify for stripper/marginal status tax reductions at the lowest level of status granted. No additional tax reductions for secondary or tertiary production were assumed for the states that grant such reduction.

Several states have additional taxes levied on production for the purpose of funding conservation, environmental or maintenance related activities. These taxes have been included in the severance tax calculations. Based on average oil and gas prices and marginal production from Table

Table 6: Production Taxes

State	Marginal Oil Severance Tax Rate	Other Taxes (Conservation, Environmental, etc.)	2005 Average Oil \$/Bbl	2005 Production from Marginal Wells (Bbls)	Annual Total Marginal Oil Production Tax Revenue	2005 Lost Production Bbls	Annual Lost Marginal Oil Production Tax Revenue	Marginal Gas Severance Tax Rate
Alabama	6.00%	—	\$53.26	911,785	\$2,913,700	1,371	\$4,382	6.00%
Alaska	15.00%	\$0.034	\$49.43	0	\$0	0	—	10%
Arizona	3.125%	—	\$0.00	31,432	\$0	0	\$0	3.125%
Arkansas	4.00%	\$0.045	\$50.86	3,317,410	\$6,898,222	45,614	\$94,851	\$0.003
California	0.00%	\$0.054	\$47.08	35,563,813	\$1,916,722	3,241,143	\$174,682	0.00%
Colorado	0.00%	0.12%	\$56.03	7,001,499	\$470,753	122,895	\$8,263	0.00%
Florida	5.00%	—	\$0.00	0	—	0	—	\$0.191
Illinois	0.00%	—	\$51.20	8,461,222	\$0	282,092	\$0	0.00%
Indiana	1.00%	—	\$51.02	1,594,296	\$813,410	6,539	\$3,336	1.00%
Kansas	0.00%	\$0.0273	\$53.41	25,827,950	\$704,328	1,473,232	\$40,175	0.00%
Kentucky	4.50%	—	\$49.45	1,958,015	\$4,357,073	18,332	\$40,793	4.50%
Louisiana	3.125%	—	\$54.04	14,152,725	\$23,900,414	436,425	\$737,012	\$0.013
Maryland	0.00%	—	\$0.00	0	—	0	—	7.00%
Michigan	4.00%	1%	\$53.67	2,657,497	\$7,131,393	68,717	\$184,402	5.00%
Mississippi	6.00%	\$0.044	\$49.58	895,452	\$2,703,190	19,278	\$58,196	6.00%
Missouri	0.00%	—	\$0.00	85,406	\$0	1,208	\$0	0.00%
Montana	9.00%	0.30%	\$52.66	1,947,855	\$9,539,386	43,393	\$212,511	11.00%
Nebraska	2.00%	1%	\$52.38	1,598,224	\$2,511,449	20,546	\$32,285	3.00%
Nevada	\$0.05	—	\$0.00	0	—	0	—	\$0.001
New Mexico	7.09%	—	\$52.84	14,065,576	\$52,694,655	348,915	\$1,307,160	8.19%
New York	0.00%	—	\$54.64	211,292	\$0	5,793	\$0	0.00%
North Dakota	5.00%	—	\$52.38	2,217,706	\$5,808,172	39,154	\$102,545	\$0.0772
Ohio	\$0.100	—	\$53.47	4,840,874	\$484,087	50,041	\$5,004	\$0.025
Oklahoma	7.195%	\$0.002	\$54.47	39,318,486	\$154,172,364	852,777	\$3,342,133	7.195%
Oregon	6.00%	—	\$0.00	0	—	0	—	6.000%
Pennsylvania	0.00%	—	\$54.57	3,652,770	\$0	37,488	\$0	0.00%
South Dakota	4.74%	—	\$50.65	54,169	\$130,049	4,013	\$9,633	4.74%
Tennessee	3.00%	—	\$0.00	235,127	\$0	12,162	\$0	3.00%
Texas	4.60%	\$0.1906	\$52.58	139,959,142	\$365,196,089	5,324,753	\$13,893,905	7.50%
Utah	0.00%	0.20%	\$53.98	1,618,810	\$174,767	51,501	\$5,560	0.00%
Virginia	0.50%	—	\$0.00	1,233	\$0	1,644	\$0	3.00%
West Virginia	5.00%	—	\$53.75	1,300,000	\$3,493,750	5,101	\$13,710	5.00%
Wyoming	4.00%	0.06%	\$45.63	8,281,804	\$15,342,688	141,415	\$261,982	6.00%
Total	—	—	—	321,761,570	\$661,356,664	12,655,541	\$20,532,520	—

6, severance taxes collected for marginal production were about \$1.2 billion during 2005. Furthermore, the production loss from marginal oil and gas well abandonments in 2005 would represent a \$32.9 million loss in severance taxes assuming average marginal production rates.

Ad valorem taxes are property taxes assessed by local government entities, and a marginal well may be subject to multiple overlapping taxing entities. As noted in prior reports, a survey of ad valorem taxation approaches in oil

and gas producing states shows the tax assessment process differs widely among the states and sometimes also within a state, with corresponding varying tax rates. While we are not aware of any published data that allows a reasonable estimate for marginal well ad valorem tax expense, our experience suggests that the ad valorem tax expense is probably a value of similar magnitude to the severance taxes.

Note: Many states have different or multiple production level cut-offs in determining marginal status. The rates shown below assume the lowest tax applicable to a marginal well producing at the lowest production level cut-off. Source: www.spee.org.

State	Other Taxes (Conservation, Environmental, etc.)	2005 Average Gas \$/Mcf	2005 Production from Marginal Wells (Mcf)	Annual Total Marginal Gas Production Tax Revenue	2005 Lost Production Mcf	Annual Lost Marginal Gas Production Tax Revenue	Annual Total Marginal Production Tax Revenue	Annual Lost Marginal Production
Alabama	—	9.02	26,757,739	\$14,480,785	183,832	\$99,486	\$17,394,485	\$103,868
Alaska	\$0.00008	4.63	0	\$0	0	\$0	\$0	\$0
Arizona	—	6.93	17,212	\$3,730	34,424	\$7,459	\$3,730	\$7,459
Arkansas	\$0.005	7.69	18,707,824	\$149,663	185,839	\$1,487	\$7,047,885	\$96,337
California	\$0.0054	7.65	4,428,540	\$2,387	722,684	\$389	\$1,919,109	\$175,072
Colorado	0.12%	7.06	88,788,233	\$751,781	1,012,032	\$8,569	\$1,222,534	\$16,832
Florida	—	9.02	0	\$0	0	\$0	\$0	\$0
Illinois	—	0.00	184,000	\$0	3,339	\$0	\$0	\$0
Indiana	—	8.53	3,134,583	\$267,447	7,428	\$634	\$1,080,857	\$3,970
Kansas	\$0.0058	6.69	283,712,000	\$1,654,041	3,227,412	\$18,816	\$2,358,369	\$58,991
Kentucky	—	7.12	82,323,314	\$26,389,935	287,324	\$92,106	\$30,747,007	\$132,899
Louisiana	—	8.07	42,130,824	\$547,701	1,398,063	\$18,175	\$24,448,115	\$755,187
Maryland	—	8.46	36,468	\$21,608	0	\$0	\$21,608	\$0
Michigan	1%	5.21	77,388,412	\$24,210,576	1,082,896	\$282,316	\$31,341,969	\$466,718
Mississippi	\$0.005	7.90	9,486,746	\$4,541,653	147,021	\$70,385	\$7,244,844	\$128,580
Missouri	—	0.00	0	\$0	0	\$0	\$0	\$0
Montana	0.30%	6.11	27,426,557	\$18,929,689	691,924	\$464,884	\$28,469,076	\$677,395
Nebraska	1%	4.36	720,360	\$125,656	0	\$0	\$2,637,105	\$32,285
Nevada	—	0.00	0	\$0	0	\$0	\$0	\$0
New Mexico	—	6.73	97,358,159	\$53,669,785	2,438,886	\$1,344,463	\$106,364,440	\$2,651,623
New York	—	9.45	9,896,329	\$0	8,825	\$0	\$0	\$0
North Dakota	—	7.76	401,057	\$30,962	17,694	\$1,366	\$5,839,134	\$103,911
Ohio	—	9.01	68,267,000	\$1,706,675	1,064,273	\$26,607	\$2,190,762	\$31,611
Oklahoma	\$0.0001	7.48	169,439,950	\$91,155,659	3,550,757	\$1,909,889	\$245,328,023	\$5,252,021
Oregon	—	5.27	0	\$0	0	\$0	\$0	\$0
Pennsylvania	—	0.00	151,651,000	\$0	484,331	\$0	\$0	\$0
South Dakota	—	7.44	399,891	\$140,932	0	\$0	\$270,981	\$9,633
Tennessee	—	9.34	2,200,000	\$616,752	69,841	\$19,579	\$616,752	\$19,579
Texas	\$0.0033	7.90	302,083,547	\$179,891,917	11,616,112	\$6,878,723	\$545,088,006	\$20,772,628
Utah	0.20%	7.10	14,429,074	\$204,794	366,065	\$5,196	\$379,561	\$10,756
Virginia	—	0.00	3,651,691	\$0	512,518	\$0	\$0	\$0
West Virginia	—	9.01	186,000,000	\$83,757,133	1,259,707	\$567,255	\$87,250,883	\$580,965
Wyoming	0.06%	6.72	89,043,042	\$36,246,953	1,376,618	\$560,383	\$51,589,641	\$822,365
Total	—	—	1,760,063,552	\$539,498,212	31,749,847	\$12,378,166	\$1,200,854,876	\$32,910,686

conclusion

The results of this study serve to quantify the economic impact of marginal oil and gas well production on the U.S. economy.

In 2005, total domestic production, including Alaska and the federal offshore areas, was 1.87 billion barrels of oil and 19.14 trillion cubic feet of gas. Marginal oil production accounted for 322 million barrels or 17.2 percent of total oil. Marginal gas production accounted for 1.76 Tcf or 9.2 percent of total gas production.

The use of RIMS II multipliers show that every dollar of marginal oil and gas production creates an additional \$1.00618 of economic activity throughout the economy, and that 9.7 jobs are dependent on every \$1 million of marginal oil and gas produced. Price levels for oil and gas and foreign country political instability are such that some companies that had focused their attention on foreign ventures have either returned or are increasing their activities in the United States. The large companies have continued their merger and consolidation process.

However, this will bring new opportunities for marginal production as the large companies optimize their property holdings to pay for the merger activity and sell the smaller, non-core assets. The high prices have also spurred activity in areas and formations that are low in productivity.

This year's report saw the total number of marginal wells to be up over 20,000 from last year. We should expect the level of marginal wells to grow at a faster trend, not only from natural production declines, but in recognition that producers are drilling more wells with less initial productive capacity.

The cumulative impact of marginal production over the 14 years this economic report has been prepared is summarized in Table 7 – 7.07 billion barrels of oil equivalent production has been achieved from these marginal producers. The lost output of the wells abandoned during this time would have represented \$9.7 billion of economic activity and more than 50,000 jobs.

During the past 14 years, states lost more than \$221.6 million in severance taxes from abandoned marginal wells.

Table 7: Marginal Wells Cumulative Impact on U.S. Economy

7.1 Oil

Year	No. of Marginal Wells	Marginal Well Production Million Bbls	Abandonments	Avg. Daily Production Per Well (BOPD)	Lost Annual Production Million Bbls	Lost Output Million \$	Lost Earnings Million \$	Lost Employment	Lost Severance Taxes Million \$
1992	453,277	368.132	16,211	2.23	15.659	\$416.935	\$55.372	2,385	\$10.443
1993	452,248	355.961	16,914	2.16	15.210	357.783	47.614	2,026	10.101
1994	442,500	339.930	17,896	2.10	16.153	359.506	48.065	2,019	10.577
1995	433,048	332.288	16,389	2.10	15.322	374.833	50.019	2,133	10.310
1996	428,842	323.468	16,674	2.06	16.452	497.243	66.086	2,829	13.688
1997	420,674	322.090	15,172	2.10	14.049	387.536	51.427	2,220	9.912
1998	406,380	316.870	13,912	2.14	11.984	216.490	28.874	1,231	5.992
1999	410,680	315.514	11,227	2.10	9.616	247.871	33.059	1,483	6.140
2000	411,629	325.947	10,718	2.16	10.122	429.997	57.505	2,333	10.618
2001	403,459	316.099	12,234	2.15	11.295	397.960	53.149	2,268	8.348
2002	402,072	323.777	13,635	2.21	13.157	468.723	62.571	2,621	10.113
2003	393,463	313.748	14,300	2.18	13.844	792.388	164.696	3,783	12.534
2004	397,362	310.922	11,977	2.14	11.305	865.535	179.932	4,028	15.879
2005	401,072	321.762	13,265	2.20	12.656	1,305.654	271.524	6,321	20.533
Total	—	4,586.508	200,524	—	186.825	\$7,118.454	\$1,169.893	37,679	\$155.188

7.2 Gas

Year	No. of Marginal Wells	Marginal Well Production Million Bcf	Abandonments	Avg. Daily Production Per Well (MCFD)	Lost Annual Production Bcf	Lost Output Million \$	Lost Earnings Million \$	Lost Employment	Lost Severance Taxes Million \$
1992	—	—	—	—	—	—	—	—	—
1993	—	—	—	—	—	—	—	—	—
1994	159,369	940.421	3,163	16.17	21.256	\$61.758	\$8.112	376	\$1.608
1995	159,669	925.563	3,189	15.87	23.053	51.853	6.771	315	1.518
1996	168,702	986.676	4,671	16.01	39.978	137.092	18.065	804	4.860
1997	189,756	1,042.153	4,661	15.72	35.839	122.772	16.192	729	3.947
1998	199,745	1,104.684	4,203	15.55	29.258	92.721	12.286	549	3.128
1999	207,766	1,138.980	3,546	15.56	24.407	80.846	10.707	481	2.799
2000	223,222	1,258.727	3,534	15.40	23.806	466.695	96.291	2,284	12.378
2001	234,507	1,353.516	3,600	15.81	24.655	397.960	53.149	909	4.716
2002	245,961	1,418.274	3,870	15.75	27.261	128.329	16.997	765	4.335
2003	260,563	1,478.106	3,883	15.54	26.889	274.231	56.033	1,329	6.745
2004	271,856	1,478.106	3,883	15.54	28.978	312.217	64.571	1,530	8.091
2005	288,898	1,760.064	4,517	16.69	31.750	466.695	96.291	2,284	12.378
Total	—	13,125.204	42,203	—	305.380	\$2,126.474	\$359.173	10,071	\$54.125

7.3 Total Oil & Gas

Year	No. of Marginal Wells	Marginal Well Production MMBOE (6:1)	Abandonments	Avg. Daily Production Per Well (BOEPD)	Lost Annual Production Million MMBOE (6:1)	Lost Output Million \$	Lost Earnings Million \$	Lost Employment	Lost Severance Taxes Million \$
1992	453,277	368.132	16,211	2.23	15.659	\$416.935	\$55.372	2,385	\$10.443
1993	452,248	355.961	16,914	2.16	15.210	357.783	47.614	2,026	10.101
1994	601,869	496.667	21,059	4.80	19.695	421.264	56.177	2,395	12.185
1995	592,717	486.549	19,578	4.75	19.164	426.686	56.790	2,448	11.828
1996	597,544	487.914	21,345	4.73	23.115	634.335	84.151	3,633	18.548
1997	610,430	495.782	19,833	4.72	20.023	510.308	67.619	2,949	13.859
1998	606,125	500.984	18,115	4.73	16.861	309.211	41.160	1,780	9.120
1999	618,446	505.344	14,773	4.70	13.684	328.717	43.766	1,964	8.939
2000	634,851	535.735	14,252	4.73	14.090	896.692	153.795	4,616	22.997
2001	637,966	541.685	15,834	4.78	15.404	795.920	106.298	3,177	13.064
2002	648,033	560.156	17,505	4.83	17.701	597.052	79.568	3,386	14.448
2003	654,026	560.099	18,183	4.77	18.326	1,066.619	220.729	5,112	19.278
2004	669,218	557.273	15,860	4.73	16.135	1,177.753	244.503	5,558	23.971
2005	689,970	615.105	17,782	4.98	17.947	1,772.349	367.814	8,604	32.911
Total	—	7,067.386	247,244	—	243.013	\$9,711.623	\$1,625.357	50,033	\$221.692

appendix: RIMS background

The U.S. Department of Commerce's Bureau of Economic Analysis prepares regional input-output multipliers that allow the estimation of the total economic impact of the addition or removal of industries or projects to a given region. The IOGCC's annual Marginal Well Report uses these multipliers to investigate the economic impact of marginal well production on 11 states and extrapolates those findings to determine the economic impact of marginal oil and gas well abandonments to both the overall economy and the oil and gas industry specifically.

Recognizing the need for a basis of estimating the economic impacts of projects and programs on a regional basis, the Bureau of Economic Analysis developed RIMS (Regional Industrial Multiplier Systems) in the mid-1970s. Enhancements to RIMS in the mid-1980s led to RIMS II (Regional Input-Output Modeling System).

RIMS II multipliers show the interdependence of economic activity throughout a given region, where a region comprises one or more counties. Multipliers are provided for output, earnings and employment, considering final demand and direct effect. These multipliers plus assumptions of projects or programs introductions into a region can be used to calculate variables such as the increase in the output value, i.e. gross receipts or sales. Multipliers plus assumptions are also instrumental in calculating earnings income such as wages,

salaries or proprietor's income less any contributions to private pension funds, and employment levels for all other industries in that region.

In some situations RIMS II multipliers have certain limitations. For instance, the multipliers are best used when total demand changes are relatively small compared to the economy of the region under consideration. Interrelations with adjacent regions are another potential source of error when the regions under consideration are small. The multipliers do not consider the possible subsequent incremental economic activity that may be associated with economic impacts of considerable relative magnitude to a region, although if such activity can be predicted, the RIMS II multipliers can be added for the expected activity to show a cumulative effect. Demand substitution can affect the RIMS II estimates, in that the multipliers assume an adequate supply of resources and labor exists within the region under study. The multipliers are static in the sense that the changes predicted are overall changes with no regard to the timing. The multipliers estimate short-term economic effects that often change over the long term. For example, multipliers may overstate job losses in the long term, as displaced employees find new jobs.

Since RIMS II multipliers are limited to the private sector, they exclude the economic impacts on state and local governments. For the proper consideration of economic

impact from marginal oil and gas production, state severance taxes and local and ad valorem taxes must be added to any estimates derived from RIMS II.

The U.S. Department of Commerce Bureau of Economic Analysis was able to provide the RIMS II multipliers for the 12 largest oil producing states: Alaska, California, Colorado, Kansas, Louisiana, Mississippi, New Mexico, North Dakota, Oklahoma, Texas, Utah and Wyoming. However, Alaska has no marginal well production reported. Its inclusion in U.S. production statistics can significantly skew the analysis results, due to the large volume of North Slope production with its corresponding low wellhead value. Therefore, Alaska is excluded in the IOGCC analysis. The remaining 11 states used for this study (referred to as the “survey states”) account for the majority of marginal oil and gas production. Average values applied for the remaining states reflect weighted averages.

The use of state level RIMS II multipliers is most accurate when the economic activity is evenly distributed across the state. This appears to be a reasonable assumption for the majority of the states considered in this study. In California, the oil and gas industry is not evenly distributed and significant other economic activity is present. These factors suggest that the potential for error in the RIMS II estimate is greater for states such as California, whereas accuracy should be better in states

with more evenly geographically distributed production, such as Louisiana.

Since the RIMS II multipliers used for this study are aggregations of regional data at the state level, it is expected that any errors introduced by the limitations previously discussed will be minimized. While RIMS II does not consider timing, many of the effects predicted in this report are based on annual values. It would follow that some portions of the predicted areas impacted, such as annual severance tax collections, could be considered as time dependent.

All previous editions of this report utilized RIMS II factors that were calculated from data gathered in the late 1980s. The U.S. Department of Commerce released updated RIMS II factors in April 2004, and these updated factors were used in this report. The old factors were aggregated into industry 8.000, Crude Petroleum and Natural Gas. The new factors are grouped into Industry 211000, Oil and Gas Extraction. The new factors are generally higher than the old factors, showing that the industry activity has a larger impact on the overall economy than what would have been calculated using the old factors. Because of the time interval between the development of the multipliers and the possible changes in the scope of what is encompassed in the industry category, it cannot be determined to what extent the old multipliers are directly comparable with the new.

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Charlie worked as director of technical services for the IOGCC beginning in 1970. In 1971 he took responsibility of assembling the data for the report and has been involved with its production each year since.

Lee began working for the IOGCC in 1954, serving as executive secretary to various Commission directors. She has assisted in the compilation of data for the Marginal Well Report since the late 1950s.

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Natural Gas Photo courtesy ALL Consulting, page 3

Oklahoma Commission on Marginally Producing Oil and Gas Wells

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abbreviations

Oil

bbls = barrels

Mbbls = one thousand barrels (1,000 barrels)

MMbbls = one million barrels (1,000,000 barrels)

BOPD = barrels of oil per day

BOEPD = barrels of oil equivalent per day

MMBOE = million barrels of oil equivalent (1,000,000 barrels of oil equivalent)

Natural Gas

Mcf = one thousand cubic feet (1,000 cubic feet)

Bcf = one billion cubic feet (1,000,000,000 cubic feet)

MCFD = one thousand cubic feet per day (1,000 cubic feet per day)

MMCF = one million cubic feet (1,000,000 cubic feet)

MMCFD = one million cubic feet per day (1,000,000 cubic feet per day)

Source: Langenkamp, Robert D., ed. The Illustrated Petroleum Reference Dictionary. 4th ed. PennWell Books: Tulsa, 1994.

APPENDIX

M



Crude Oil Market Infrastructure Task Force

EXECUTIVE SUMMARY

Introduction

At the beginning of 2006, domestic crude oil producers in the Rocky Mountain region began to receive much lower prices for their production than similar quality oil sold in other parts of the country. The lower prices resulted from crude oil supplies far exceeding demand. At the same time, a separate set of supply and demand market forces kept prices high for refined products in the region. While crude oil producers bore the brunt of the price collapse, governments at the federal, state and local levels were also impacted as a result of greatly reduced royalty payments, which are based on product sales value. In addition, state and local tax receipts suffered enormous revenue losses as well. The falling value of the crude oil itself could also result in a premature abandonment of the resource and a cutback in domestically produced petroleum—key concerns of the Interstate Oil and Gas Compact Commission (IOGCC).

As a result of these changing market conditions and the glut of crude oil in the Rocky Mountain states, during the first half of 2006 local domestic oil producers in those states were receiving as much as \$25 to \$30 per barrel less than what was paid for similar quality oil in other regions of the country. While these price differentials have declined to about \$6 to \$10 per barrel in the last half of 2006, the differentials remain much higher than the historical average of \$1 to \$3 per barrel. Furthermore, the imbalanced supply and demand conditions that caused the highest differentials in the early part of 2006 remain in place, and may cause further problems in the future.

In May 2006, IOGCC Chairman Dave Freudenthal, Governor of Wyoming, created a task force to specifically identify

the reasons that domestically-produced crude oil within the Rocky Mountain region was receiving significantly lower well head prices than similar oil sold in the rest of the country. The task force included representatives from Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming, the Province of Alberta, the U.S. Department of Energy and the Federal Energy Regulatory Commission (FERC). Gov. Freudenthal charged the task force to:

- *investigate the crude oil market dynamics in the Rockies*
- *identify the conditions causing the precipitous price drop, and the expected duration of these conditions*
- *recommend both near and long-term actions that could be taken to correct this situation*

Some of the factors evaluated by the Rocky Mountain task force included the impact of asphalt use, increased crude oil production in the Rockies, increased crude oil production in western Canada, refining capacity, pipeline capacity and crude oil quality variation. Some of the data considered by the task force included the number of new well permits, well completions, production quantities and trends, state tax information, forecasts for Canadian imports and Rockies regional production, existing pipeline and refinery capacities, plans for increasing pipeline and refinery capacities, and existing and proposed state and federal legislation.

This report is the result of the work of that task force.

Background

Prior to 2006, the crude oil markets in the Rocky Mountain states were generally in balance with supplies from local production and imports meeting the needs of the refineries in the region while any surplus production was exported out of the region to other areas of the country. Under these conditions, the price that local producers received for their crude oil was similar to prices throughout the country. However, these conditions changed drastically at the beginning of 2006. A confluence of supply and demand factors came together at that time resulting in a significant over-supply of crude oil in the Rocky Mountain states as compared to demand for that oil. As a result of this oil glut, local producers began to receive prices as much as \$25 to \$30 per barrel less than similar quality oil sold in other parts of the country. At the same time supply and demand for refined products in the region kept those prices high. While producers bore the bulk of the price collapse; federal, fee, and state royalties as well as state and local tax receipts suffered enormous revenue losses as well.

Factors that contributed to and may continue to contribute to market volatility in the Rocky Mountain region relative to other regions include the following:

- ***Supply - Increasing Local Production***
Crude oil production in the Rockies is no longer declining, and in some areas, dramatic growth in production has occurred. This growth is anticipated to continue over the course of the next five to ten years. Specifically, North Dakota and Montana production, primarily in the Williston Basin, is growing more rapidly than in any other State in the region.

Twenty years of production decline in Wyoming has been reversed in 2006 as a result of successful enhanced oil recovery operations and condensate production increases in the Jonah/Pinedale area. Growth in the Uintah Basin of Utah and along the Utah Hinge Line area also continues and could accelerate.

- ***Supply – Increasing Imports from Canada***
In May 2005, the Express Pipeline bringing Canadian

crude oil into the region expanded its capacity and actual imports of Canadian crude increased by an average 15,000 barrels of oil per day (bpd).

- ***Demand – A Decline in Demand by Refineries***
From January to March 2006 Rockies refinery consumption declined due to refiners reducing demand as they upgraded their facilities to Ultra Low-Sulfur Diesel (ULSD) specifications, shifted from heating oil to gasoline production, scheduled maintenance, and forced outages.
- ***Demand - Pipelines Moving Crude Oil Out of the Region***
The Enbridge Pipeline and the Platte Pipeline are the only two major crude oil pipelines that can move oil out of the region to other parts of the country. The Enbridge Pipeline became full in February 2005. The Platte Pipeline became full in December 2005. Having both pipelines at capacity created a bottleneck limiting the amount of oil that can be moved out of the region.

Conclusions

The task force concluded that extreme crude oil market volatility in several producing regions of the Rockies resulted when limited pipeline and refinery infrastructure was impacted by equipment failures and production growth. Factors that contributed to and may continue to contribute to market volatility in the Rocky Mountain region relative to other regions include the following:

1. While the supply and demand were closer to being in balance since the early summer, excess supplies are still causing significant price differentials, albeit at lower levels.
2. In the next few years, Canadian imports will continue to increase. Canadian imports are reliable supplies from a secure country – i.e., good for energy security. On the other hand, Canadian imports are a concern in the sense that they can overload regional take away

capacity and depress local prices. The key is to eliminate the bottlenecks that prevent oil in the Rockies from reaching destinations where it can maintain higher values.

3. Exporting pipeline capacity is expected to increase, although it is unclear if proposed capacity increases will be adequate.
4. There has been no significant change in refinery capacity in the region of study in the last 20 years. Although incremental expansions are being considered, none have been announced.
5. The production of Canadian heavy sour crude oil and Canadian synthetic crude oil has increased and refinery modifications have concentrated on processing sour crude. Regional U.S. production increases have been predominately sweet crude oil. With refinery demand staying constant, supply is now exceeding demand. The result is more crude oil needs to be exported out of the region; however, the export pipelines are already at full capacity.
6. Those who capitalized upon the changing market conditions and the glut of oil in the Rockies states did so at the expense of diverting supplies that they might otherwise have purchased under spot and term contracts.
7. Additional growth in regional production can be anticipated if prices and demand remain strong. In addition, growth in the Uintah Basin of Utah and along the Hinge Line area also continues and could accelerate. Additional growth can be anticipated in the 2012 to 2015 period if crude oil prices stay at current or higher levels and shale oil is developed.

Recommendations

The task force generally recognized that the underlying issues associated with market dynamics will not change over the short term. The group also concluded that crude oil imports

from Canada are extremely important to the nation's energy mix, and the challenges of transportation of these resources to appropriate markets should be addressed.

Without the expansion of infrastructure (pipelines and refinery capacity) and a more coordinated regulatory framework, the continued growth in both Rocky Mountain region and Canadian production will lead to increased crude oil market volatility in the region.

Timing of refining and pipeline expansions is uncertain as market participants attempt to sort out who is going to commit to and pay for new infrastructure.

Ultimately, market forces will prevail and expanded and/or new refinery capacity and expanded and/or new pipeline facilities will be built to accommodate growing production from the region. An unsatisfactory outcome would be for market forces to stunt production growth in the region as market volatility reduces or eliminates the return on exploration and production investment. The ultimate effect of this scenario would be the loss of this resource to U.S. energy consumers.

The Task Force believes that during the time that market forces drive expansion of capacity or construction of new capacity that there are several things that can be done to better educate the marketplace on crude oil dynamics and that IOGCC participants can implement to provide market expansion sooner rather than later:

1. The IOGCC should commission an annual study of each critical pipeline hub within the United States. This study should examine the volume of incoming crude, including local production and imports, with the available takeaway capacity, including refining consumption and pipeline export capacity. These results should be used to proactively promote pipeline and refinery development or other solutions that ensure a "healthy" marketplace.
2. The IOGCC should provide a platform where crude oil pipelines serving major hubs post capacity and aggregated, nominated volumes on a monthly basis.

Recommendations Cont'd

- This platform would include current and historical information in order to increase transparency to the marketplace and provide producers and marketers a useful tool from which to determine if they need to add capacity to their markets.
3. The FERC should continue to adopt policies that promote infrastructure development.
 4. The IOGCC should form a task force comprised of one regulatory member from each State to develop a model regulatory framework under which pipeline companies desiring to build new projects can operate. This will eliminate state by state confusion and should accelerate permitting and construction of new pipeline and refining projects.
 5. The IOGCC should form a task force directed at working with Tribal groups to develop a model regulatory framework under which pipelines can cross Tribal lands.
 6. States and the federal government should consider offering cost-effective tax incentives or royalty relief to producers, pipelines, and refiners if they commit to new build or expansion projects. Developers should be provided incentives to build “slack” capacity into their systems.
 7. The IOGCC should promote the understanding that it is important to U.S. energy security that additional pipelines be built to carry Canadian crude to major U.S. refining centers. New and existing pipelines carrying Canadian crude oil should work with domestic producers and marketers to create receipt points for domestic crude to be shipped on their pipelines. In addition, crude oil pipelines should be permitted to sell firm service to shippers – especially on new pipelines.
 8. The IOGCC should promote the understanding that localized prices in each state may fall out of favor from time to time due to changes in market forces such as imports, local production, refining capacity, pipeline capacity, crude quality and maintenance issues. Producers should be encouraged to work together to develop solutions that will assist in moving their oil to better valued markets. Aggregation of crude will assure the most efficient and economic development of pipeline or refining upgrades to each situation.
 9. The IOGCC should work to streamline the overly burdensome, inconsistent and time-consuming refinery permit process by improving state, local and federal coordination, ensuring adequate resources at permitting authorities to shorten review timeframes, and empowering the U.S. Department of Energy to serve as a facilitator for timely permit reviews. Such projects should be viewed as a high priority due to national energy, national security and economic considerations.
 10. The IOGCC should encourage Congress to codify the U.S. Environmental Protection Agency’s (EPA) comprehensive reform of the New Source Review (NSR) regulations, including those that prohibit states from developing patchwork variations of the NSR process, which are stymied in judicial appeals.
 11. The IOGCC should work to align National Ambient Air Quality Standards (NAAQS) deadlines to take advantage of the significant emissions reduction benefits achieved by existing federal regulation. Changes to consider during the 2010 statutory review cycle include standards relating to ozone and fine particulate matter.

About the IOGCC

The IOGCC, representing the governors of 30 member and seven associate states, promotes the conservation and efficient recovery of the nation’s oil and natural gas resources while protecting health, safety, and the environment. Established by the charter member states’ governors in 1935, and approved by Congress, it is the oldest, largest, and most effective interstate compact in the nation.