Probabilistic Risk Based Decision Support for Oil and Gas Exploration and Production Facilities in Sensitive Ecosystems

Semi-Annual Management Progress Report

Reporting Period: October 1, 2006 through March 30, 2007

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Report Date: May 2007

Project Number: DE-FC26-06NT42930

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DISCLAIMER

Acknowledgement

This research was sponsored by the U.S. Department of Energy through the National Energy Technology Laboratory (grant # DE-FC26-06NT42930).

Abstract

This report describes work performed during the initial period of the project "Probabilistic Risk Based Decision Support for Oil and Gas Exploration and Production Facilities in Sensitive Ecosystems." The specific region that is within the scope of this study is the Fayetteville Shale Play. This is an unconventional, tight formation, natural gas play that currently has approximately 2 million acres under lease, primarily to Southwestern Energy Incorporated and Chesapeake Energy Incorporated. The currently active play encompasses a region from approximately Fort Smith, AR east to Little Rock, AR approximately 50 miles wide (from North to South). The initial estimates for this field put it almost on par with the Barnett Shale play in Texas. It is anticipated that thousands of wells will be drilled during the next several years; this will entail installation of massive support infrastructure of roads and pipelines, as well as drilling fluid disposal pits and infrastructure to handle millions of gallons of fracturing fluids. This project focuses on gas production in Arkansas as the test bed for application of proactive risk management decision support system for natural gas exploration and production.

The primary activities of the initial period included the identification of stakeholders and meetings with representatives from these groups to get their input regarding the utility of specific project components and direction that the project should move in order to produce the most benefit. Briefly, meetings were held with state and federal regulators and industry representatives during which issues of importance to the stakeholders were identified and discussed. Chief among the concerns from all stakeholders was security of data and information. Industrial representatives do not want information such as what areas are being

considered for future development to be retrievable (e.g. through database usage statistics). Regulatory concerns for data security focused on sensitive information (e.g. threatened species locations) being available on a public server.

Another content component that was identified as important to the industrial participants was the inclusion of an educational page where the activities associated with the life cycle of a lease in the Fayetteville Shale would be explained for both the public (to improve public perception of the environmental stewardship of the industry) and regulatory community (to ensure understanding of the stages of operation).

An initial draft regulatory summary was prepared that documents the state regulations affecting the Fayetteville Shale. However, during a regulatory stakeholder meeting, we were informed that the regulations from the Arkansas Oil and Gas Commission were in a state of flux, and that it would be later in 2007 before the complete rules were finalized. During the same meeting, it became apparent that another significant aspect of this project should include facilitated and streamlined lines of communication between the regulatory agencies (both regulatory and advisory bodies as well as state and federal communications.)

Executive Summary

Exploitation of a significant natural gas reserve in central Arkansas, the Fayetteville Shale Play, will necessarily require development of significant infrastructure. Thousands of wells and hundreds of miles of roads will be constructed, as well as reserve pits and disposal options for fracture fluids. The project, "Probabilistic Risk Based Decision Support for Oil and Gas Exploration and Production Facilities in Sensitive Ecosystems," was proposed to develop modules for a web-based decision support tool that will be used by mid-and small-sized oil and gas exploration and production companies as well as environmental regulators and other stakeholders to proactively minimize adverse ecosystem impacts associated with the recovery of oil and gas reserves in sensitive areas in the Fayetteville Shale Play in central Arkansas. Another important aim of this project is to provide a mechanism that will help to streamline the process of acquiring a permit for drilling in the play.

The first phase of the project required identification of and contact with stakeholders involved in the Fayetteville Shale Play (FSP). The principal stakeholders and their affiliations are presented in Table 1.

Table 1. Fayetteville Shale Play Stakeholders

Regulatory/Governmental Stakeholders		Role
Larry Bengal	Arkansas Oil and Gas Commission	Primary regulatory body for exploration, drilling and production
Keith Brown Laura Stuart-Leslie	Arkansas Department of Environmental Quality	Regulates reserve pits
Ed Ratchford	Arkansas Geological Commission	Repository of geological data
Todd Fuggit Chris Kelly	Arkansas Natural Resources Commission	Well head and water well protection
Bill Holiman	Arkansas Natural Heritage	Maintains database of

Cindy Osborne Chris Colclasure	Commission	endangered species
Ken Adams	Bureau of Land Management	Oversees resource extraction on all federal lands
Wayne King	US Forest Service	Defines allowable surface impacts on federal land
Chris Davidson	US Fish and Wildlife Service	Enforcement of Threatened and Endangered Species Act
Sara Usdrowski Marc Fossett Elaine Edwards	US Army Corps of Engineers	Enforces section 404 of the Clean Water Act
Industrial Stakeholders		
John Thaeler Mike McAllister	Southwestern Energy	Resource extraction
Paul Hagemeier John Satterfield	Chesapeake Energy	Resource extraction

Three stakeholder meetings were held and overall the discussions were positive and indicated a strong willingness of the industrial and regulatory parties to collaborate with each other and the project team to help create a tool that will be beneficial in the development of the Fayetteville Shale Play. The major themes that emerged as areas where the greatest benefit to the stakeholders would be felt were education and integration. The industry's perception is that there is a need for education. There was also general agreement that more efficient communication between the regulators and industry would be a significant benefit. There was some discussion regarding the scale/scope of this project with respect to the proposed fate and effects/ risk modeling. Current practice requires an on-site survey to be completed by a registered surveyor, and there was a strong concern expressed from the industrial participants that risk modeling based on remotely sensed digital elevation models and existing soil type maps would not be extremely useful and could potentially lead to conflict

if the model recommendations were subsequently overruled by on-site survey results. Based on these concerns, the proposed tasks relating to this work were placed on hold.

We have also identified, through discussions with regulators and other governmental agencies, what the principal roles of each agency are. These are briefly described in Table 1 above. Another request by the stakeholders is an educational component to the LINGO website which will provide information on current industrial practice.

Conclusions

Based on feedback from the stakeholders, some tasks will be modified (as described in more detail in the report body) and new tasks will be added. In particular, an educational component to the web based tools will be included to provide a resource for land owners and regulators who need detailed information regarding the current industrial practices in the FSP. Both industry and governmental stakeholders agreed that a web based tool for facilitating communication would be of significant benefit.

Future efforts will focus on development of a prototype web site based on an existing web infrastructure that is in development form the management of BMPs in Arkansas wetlands (http://awrims.cast.uark.edu/home/). Other work will focus on application of Bayesian based "fuzzy-logic" system that takes into account the uncertainty associated with the various GIS layers used as input as a means to address industry concern over the use of "low resolution" remotely sensed GIS data in the decision models.

Probabilistic Risk Based Decision Support for Oil and Gas Exploration and Production Facilities in Sensitive Ecosystems

1. Introduction

The Fayetteville Shale play is an unconventional natural gas play across central Arkansas. It is a tight formation and requires fracturing to produce economic quantities of gas. Initial estimates are that it may rival the Barnett Shale play in Texas. There are currently approximately two million acres under lease in this play[1]. It is anticipated that thousands of wells will be drilled during the next several years; this will entail installation of massive support infrastructure of roads and pipelines, as well as drilling fluid disposal pits and infrastructure to handle millions of gallons of fracturing fluids. This project is focused on gas production in Arkansas as the test bed for application of proactive risk management decision support system for natural gas exploration and production.

The project will develop a series web-based application modules that will allow mid- and small-sized exploration and production companies to generate development plans for resource extraction in sensitive ecosystems in a manner that will meet regulatory requirements and proactively minimize risks to the ecosystem through implementation of best management or development practices developed on a site specific basis. The program will be built from a database of existing technologies that can be implemented in ecosystem friendly ways. The principal objective of this project is development of tools that will allow industry to rapidly

[1] Poynter, B. 2006. Arkansas Oil and Gas Commissioner, Personal Communication

evaluate alternative leases through a GIS-based probabilistic risk management approach so that location-specific environmental concerns can be identified early in the permitting process.

This project is an extension of a recently completed DOE-funded project, "Risk Reduction and Soil Ecosystem Restoration in an Active Oil Producing Area in an Ecologically Sensitive Setting," (DE-FC26-01BC15332). This project was focused on mitigating environmental impacts associated with the aging infrastructure of much of the domestic petroleum production industry. The risk reduction portion of the project was built on probabilistic reliability analysis of equipment used in the field to predict the probability of a release of produced fluids. This analysis is coupled with a GIS-based fate and effects model which is linked to a natural resources damage assessment and remediation model to generate a ranked risk index map of the lease as a decision support tool for allocation of maintenance resources. The basic approach is to link the likelihood of a piece of equipment experiencing a failure and releasing produced fluids with the calculated cost to cleanup the hypothetical spill at the location of that equipment. The combination of the likelihood of failure with the financial consequence of the failure defines the risk at that location; risks can be ranked and compared across an entire lease. The prediction of risk allows for ***proactive*** risk management. The general framework of this approach can be extended and adapted to a proactive risk management decision support tool throughout the entire lifecycle of exploration and production activities in other sensitive ecosystems.

Exploring for oil and gas involves subsurface seismic mapping which results in surface disturbance; it often involves small explosive charges placed in patterned grids. If potential oil or gas deposits are identified, exploratory drilling begins. This phase frequently requires

constructing, operating, and maintaining a system of access roads, local pipelines to connect well sites to storage facilities and dispose of drilling wastes, and gravel pads to house equipment. In addition, production may require storage tanks, separating facilities, and gas compressors. Finally, gathering lines are needed to transport oil and gas to production facilities or to users. Pipeline operation may require additional pumping stations and storage tanks.

Habitat fragmentation is one of the primary concerns associated with the development of new E&P infrastructure. It can change the hydrology of the basin, potentially introducing toxic substances and sediment into surface waters. Fragmentation also increases disturbances from human activities, may provide corridors for predators, and potentially helps spread non-native plants.

Impacts in the drilling stage include disturbed land, which can be significant depending on the length of roads, size of equipment, and other factors. The movement of heavy vehicles and drilling can create continuous noise potentially disturbing wildlife behavior patterns. Emissions from diesel engines and turbines that power the drilling equipment can pollute the air with particulates and carbon monoxide.

This project will provide oil and gas planners, engineers, developers, cultural resource managers, and researchers with a decision support system able to present information and maps from a variety of geospatial data, for any proposed site or corridor location. The system will be accessed early in the planning process to quickly evaluate the potential of alternatives; to provide an estimate of the relative costs and time delays that each alternative might be expected to yield, to highlight sensitive areas and features, and to minimize adverse environmental impacts. Implementation of the tools assembled for this project will lead to a

streamlined permitting process for well placement and infrastructure development. As the Fayetteville Shale play develops, the number of drilling and reservoir pit permits will increase and may ultimately lead to a situation similar to that found in the Rocky Mountain region where the regulators are unable to keep up with permit processing with the result that environmental monitoring responsibilities are not effectively executed.

In this report we summarize the work performed during the first six months of the project, which has focused primarily on the identification of stakeholders and solicitation of feedback on the proposed project objectives.

2. Project Tasks for current reporting period

Task 0: Identify and establish contact with stakeholders.
Task 1: Technology Evaluation
Subtask 1.1 Analysis of existing practices
Subtask 1.2: Identification of best practices
Task 2: Delineate regulatory and environmental concerns in the region and database development .
Task 3: Adapt fate and effects and ecosystem effects models

3. Results

On October 11, 2006 we held the first stakeholder meeting. The following people attended (in addition to the project team):

Mike McAllister, SEECO, Inc.
John Thaeler, SEECO, Inc.
Paul Hagemeier, Chesapeake Energy, Inc.
Steve Gates, AOGC
Keith Brown, ADEQ
Chris Davidson, US Fish and Wildlife
Ed Ratchford, Arkansas Geological Commission

Overall the discussions were positive and indicated a strong willingness of the industrial and regulatory parties to collaborate with each other and the project team to help create a tool that will be beneficial in the development of the Fayetteville Shale Play. The major themes that emerged as areas where the greatest benefit to the stakeholders would be felt were education

and integration. The industry's perception is that there is a need for education. There was also general agreement that more efficient communication between the regulators and industry would be a significant benefit to all. There was some discussion regarding the scale/scope of this project with respect to the proposed fate and effects/ risk modeling. Current practice requires an on-site survey to be completed by a registered surveyor, and there was a strong concern expressed from the industrial participants that risk modeling based on remotely sensed digital elevation models and existing soil type maps would not be extremely useful and could potentially lead to conflict if the model recommendations were subsequently overruled by on-site survey results. Based on these concerns, project tasks associated with fate and effects modeling have been placed on temporary hold.

Education: The industry representatives indicated that having a central location where all interested parties could access information about industrial practice would be very useful. They agreed that there is a public perception that oil and gas E&P operations are always bad for the environment. While all development carries an environmental cost, industry representatives want their existing corporate cultures, policies and practices of using minimally damaging modern technologies to be explained in a straightforward manner to the public (and to make all of the regulatory community aware of these practices). Both SEECO and Chesapeake offered to provide educational materials, in particular, information detailing the life-cycle of a typical gas lease and their current practices.

Integration: The stakeholders present agreed that improving inter-agency communication through the permitting process would result in a more streamlined mechanism for the close cooperation of the agencies involved in the regulation of the FSP. The outcome of this

identified need will be to develop web-based communication tools that help the regulatory (and non-regulatory, but concerned) agencies provide information to the operators in a timely fashion. For example, information available that will allow the operators to quickly screen a section for potential development *vis a vis* the presence of threatened / endangered species that can be matched with maps of existing roads and streams to provide guidance on the appropriate planning of access roads and drill pad placement.

Datasharing: Interest from the industry regarding the availability of information from each of the regulatory bodies was expressed – having the information compiled by different agencies that is publicly available merged into an easily accessible forum would be beneficial. There was also discussion about the need to protect information that originates from both the government/regulatory side (e.g. endangered species locations, cultural resources) and from the industry regarding when their use of the tool would be publicly known (i.e. protection of preliminary investigation as part of their business planning that is proprietary).

In this meeting, we identified several additional stakeholders who should be included: Arkansas Natural Resources (formerly Soil and Water), Department of Health (well head protection), US Army Corps of Engineers, Arkansas Natural Heritage Commission, US Forest Service, Arkansas Natural Heritage Commission, and the BLM.

Another outcome of the first meeting was a plan to conduct a meeting with all the government agencies separately from the industrial participants.

A follow up meeting with the regulatory/governmental agencies was held on December 18 at the ADEQ offices in Little Rock.

The following representatives attended:

Chris Davidson, US FWS
Keith Brown and Laura Stuart-Leslie, ADEQ
Ken Adams, BLM (invited, but did not attend)
Ed Ratchford, Arkansas Geological Commission
Sara Usdrowski, Marc Fossett, and Elaine Edwards , US Army Corps of Engineers
Todd Fuggit and Chris Kelly, Arkansas Natural Resources Commission
Bill Holiman, Cindy Osborne, and Chris Colclasure, Arkansas Natural Heritage Commission
Wayne King, US Forest Service
Larry Bengal, AOGC

During this meeting representatives of each agency discussed their roles and concerns regarding the development of the Fayetteville Shale Play. These are summarized below.

Bureau of Land Management / US Forest Service: Forest Service lands in the FSP fall under the jurisdiction of the Bureau of Land Management. The procedures for permit application are given in the 'Gold Book.' The preferred approach in Arkansas is through the Notice of Staking procedure. Here the driller notifies FS personnel of the intention to place a well at a site. The FS then will perform an on-site inspection within 10 days. At that time the operator may be asked to move the pad or re-route access roads. Typically an FS engineer will stake the centerline of the access road that the FS believes to be the least damaging to the site. Subsequently, the operator submits an Application for Permit to Drill (APD) which will include a plat of the site including pit, pad, culvert, and road locations. The BLM and FS have responsibility for ensuring compliance with the EPA National Environmental Policy Act, and will perform an environmental impact analysis of the proposed drilling prior to issuing approval of the ADP. If a mechanism could be implemented that would provide for the inclusion of all the activities (pit, pad, roads, as well as gathering lines) in a single application, Mr. King, the FS

representative, indicated he felt that there could be an improved turnaround time for the approval process.

US Army Corps of Engineers: The USACE has jurisdiction over all navigable waterways in the United States, known as §10 waterways. USACE oversight authority arises from §404 of the Clean Water Act. A §404 permit is required if a road or pipeline crosses a §10 waterway. USACE is also interested in sediment load to rivers and streams associated with drilling operations – although small scale operations are exempt from permitting requirements related to stormwater and sediment management. There seemed to be some confusion regarding exactly when §404 requires a permit – Larry Bengal indicated that his belief was that many sites were installed without knowledge of any USACE requirements. An example was that any construction causing a surface disturbance in a wetland or below the highwater mark of a stream requires a §404 permit. In general, the USACE wants erosion and sediment control plans for Fayetteville Shale Play development activities. At present there does not appear to be a good mechanism to insure that subcontractors of the major operators are aware of these requirements.

Arkansas Oil and Gas Commission: The AOGC regulates all aspects of oil and gas E&P on State and Private (but not Federal) lands in Arkansas except reserve pit construction and land disposal of drilling mud and fracture fluids. Larry Bengal, the director of the AOGC, indicated that there were a number of significant changes currently in development with respect to the AOGC's regulation of E&P activities in the Fayetteville Shale Play. In particular, AOGC is eliminating the field rules for the Fayetteville Shale Play. There are other changes anticipated, but at the time of the meeting these were not clear. An important aspect of this project is the

integration of the permitting process into the web based tools; however, with the current state of flux with regard to the AOGC it is difficult to proceed.

Mr. Bengal addressed concern from the Arkansas Natural Resource Commission regarding the impact of drilling and production activities on the state's groundwater supplies by indicating that there are currently rules in place that stipulate multiple casings of all wells in the Fayetteville Shale Play to a depth of 500 feet. He felt this was adequate to protect shallow aquifers. The AOGC regulates all class II UIC wells in Arkansas for injection of waste fluids (e.g. fracture fluids and drill cuttings); more permits for class II wells are anticipated as the Fayetteville Shale Play develops. New DOT rules will put the AOGC in conflict with the Public Service Commission with regard to the jurisdictional control of pipelines in the Fayetteville Shale Play. In particular, individual sections of gathering lines may fall under DOT regulations rather than AOGC regulations, and depending on the level of development near the line the designation could change on an annual basis – this is causing AOGC to consider revision of its pipeline rules.

Arkansas Department of Environmental Quality: This agency regulates reserve pits where drilling fluids are temporarily stored during the drilling operation. A general permit is currently being drafted for land application of drilling fluids with requirements specific to the Fayetteville Shale Play and will be available for public comment as the next stage of its implementation. In 2006, there were 619 reserve pit applications. The ADEQ also has §401 jurisdiction through the Clean Water Act §404 regarding degradation of surface water quality associated with sediment runoff. Although the Oil and Gas industry is exempt from permitting requirements associated with stormwater runoff for sites smaller than 5 acres, they are still expected to implement Best

Management Practices and remain subject to state laws regarding degradation of water quality (§401).

Arkansas Natural Heritage Commission: The ANHC is involved both as a land owner and as the repository of information about the location of threatened and endangered species in Arkansas. Cindy Osborne indicated the possibility of including 'Red Flag' information to this project. This would be only an indication that further detailed study of a potential drill site's impact on T/E species would be required prior to construction. Detailed information on the locations of rare species is never made available directly to the public.

Arkansas Geological Commission: This agency has no regulatory authority. It does serve as a repository of a large amount of detailed geological information for Arkansas and the Fayetteville Shale Play in particular. Their products include maps of the known locations of drilling and production wells and subsurface formations. Ed Ratchford has been very interested in providing assistance and information for this project.

US Fish and Wildlife Service: Chris Davidson has been preparing a multi-agency document that outlines Best Management Practices for E&P in the Fayetteville Shale Play. The FWS does not play a direct regulatory role in the development of the Fayetteville Shale Play, but they must be consulted any time there is a 'federal nexus' (Clean Water Act Permits, EPA Authority, possibly BLM permitting for drilling on federal lands). This authority derives from §7 of the Endangered Species Act of 1973, and is primarily concerned with protection of critical habitat. The FWS and USFS have already cooperated on the analysis of the effects of seismic studies in the Fayetteville Shale Play. Both the FWS and ANHC representatives expressed concern regarding habitat fragmentation during the development of the Fayetteville Shale Play. These

concerns were voiced with regard to aquatic habitats that may be impacted by water withdrawal for use in fracturing jobs; with regard to roads and pipelines providing easy avenues for invasive plants to penetrate sensitive habitats.

On March 16 a meeting with representatives from Chesapeake Energy and Southwestern Energy was held at UAF.

Participants:
John Thaeler, SWN
Mike McAllister, SWN
Wayne Holder, HSE coordinator, SWN
Paul Hagemeier, Chesapeake
John Satterfield, Chesapeake

John Veil, Argonne National Labs
Khursheed Karim, UA
Lyda Zambrano, UA
Jackson Cothren, UA
Greg Thoma, UA

At this meeting we provided an update to the industry representatives of our activities with the regulators.

During the meeting the industry representatives showed interest in:

- Having a web-accessible summary document with all the agencies involved in the permitting process; they believed it would be useful especially for small producers.
- A mapping system with GIS overlays, to gather information upfront about historical sites and wildlife in intended drilling areas.

There is a perception that communication between the agencies (both federal and state) will speed up the permitting process. They expressed their concerns about the lack of communication between state and federal agencies.

There was a comment that county Judges want to be included in the permitting process with regard to road impact (erosion).

When presented with the idea of having a 'real-time' database that will show the status of the permits they expressed concerns about the confidentiality of the information. The access to a database with the permits should be confidential, not allowing outside organizations access to the information to avoid delays to process. However, pooling of existing permits in a single location was viewed positively.

The industry representatives did not like the idea of having a decision algorithm to choose the BMP applicable in the drilling area. They indicated that one of the problems is that BMP are scattered among several agencies and might be difficult to gain consensus.

They reiterated the need for an educational component to the website.

They indicated that all O&G operators should agree to BMP's, the recommended practices should be site specific and available to all size operators.

4. Summary of state permitting requirements

Appendix A contains a full report of the state permitting requirements. However, this document should be considered a draft version because during the 12/18 meeting with the regulatory group, Larry Bengal, the director of the Arkansas Oil and Gas Commission informed the group that the AOGC was in the midst of significant revisions of their regulations. These changes have not yet been published.

Figure 1 presents an outline of the regulatory stages in the permitting cycle of a lease.

Lease Life Cycle / Permitting Requirements

Industrial

1. Gaining Access to the Resource
    1. Mineral Rights
    2. Leasing of Mineral Rights
2. The Unit Integration Process
3. Searching for Oil and Gas
    1. Seismic Studies
    2. Exploratory Wells
4. Drilling Production Wells
    1. Casings
    2. Directional Drilling
5. Preparing Wells for Production
    1. Well Completion
    2. Hydraulic Fracturing
        1. Water management
        2. Water supply
6. Production
    1. Transportation and Processing
7. Well Closure

State

1. AOGC Responsibilities
    1. AOGC Fayetteville Shale Field Rules
    2. Unit Integration
2. Searching for Oil and Gas
    1. AOGC Seismic Application
    2. Siting and Drilling Wells
    3. Endangered Species Act Considerations
3. Notice of Intent
    1. AOGC Rule B -14 to B-16
4. Drilling Wastes and Reserve Pit
    1. AOGC
        1. Disposal of Reserve Pit Fluids
    2. ADEQ
        1. Oilfield waste and reserve pits
    3. ADHHS
5. Well Completion
    1. AOGC Well Completion Report
6. Gas Production
    1. Notice of commencement
    2. AOGC rules D -1 to D-19
7. NPDES
8. Produced Water
    1. ADEQ general permit
    2. Underground Injection (Reg. 17)
9. Plugging and Abandonment
10. Other Environmental Permits ?

Federal

1. BLM
    1. 'Gold Book"
    2. Forest Service controls surface activities
        1. NEPA and Council on Environmental Quality (CEQ) regulations
2. Notice of Intent & Authorization for Exploration
    1. Forms 2150 -4F/S & 2800-16
        1. Not required if BLM mineral w/ non -federal surface owner
    2. Map with 2D lines; access routes; schedule
        1. Cultural Heritage survey (possible requirement
        2. T&E species survey (possible requirement
    3. Forms 3150 -5F/S & 2800-16a upon completion of exploration operations
3. Permitting and Approval
    1. Application for Permit to Drill (APD)
        1. Electronic filing available
        2. Onsite inspection for site -specific concerns
    2. Stipulations and Conditions
        1. AR Natural Heritage (see 2.2.1)
        2. Fish and Wildlife (see 2.2.2)
        3. BLM approval does not supersede other requirements
4. Construction and Maintenance
    1. Well site selection guidance
    2. Reserve pits – clay or other liner
    3. Roads and Access Ways
    4. Drainage
    5. Well Completion Report
    6. Measurement of Production
5. Reclamation and Abandonment
    1. Well Site
    2. Road
    3. Other Facilities
    4. Inspection/Bond release
6. US Army Corps of Engineers
    1. Pre-Application Meeting with other necessary agencies and internal interests
    2.) Submittal of Application, ENG Form 4345
        1. erosion control plan, mitigation plan
        2. Cultural resources information
        3. determination of limits for waters of US
        4. Possibly concurrent application with FERC

Conclusions:

While there are two state agencies with regulatory authority (ADEQ and AOGC), and the BLM with regulatory authority over federal lands, several of the other agencies have the potential to become involved on a case by case basis. One significant observation during this meeting was that, while there is a general understanding between the agencies of each agency's role, there is no routine communication between the agencies during or after the permitting process. Both the governmental agencies and the industrial participants agreed that a site to facilitate communication would be of significant benefit to the development of the FSP in an environmentally friendly manner.

There was no support from the industrial community for the fate and transport modeling proposed for use in proactive risk management of drilling sites; the principal concern focused on the current practice of on-site surveys and the comparative lack of accuracy available for pre-survey probabilistic modeling.

Progress on task completion:

Phase 1: Development of Environmentally Friendly Technologies Database

Task 0: Identify and establish contact with stakeholders.

This task is complete. Stakeholders include those listed in the February Project Summary. In the March meeting with industrial stakeholders, there was a passing suggestion that county judges should also be considered stakeholders because of their role in the construction of roads. However, we have decided to not add these individuals at the present in order to maintain manageability of the groups.

Task 1: Technology Evaluation

Subtask 1.1 Analysis of existing practices

This task is behind schedule. This is primarily the result of the effort and time required to identify, contact, and organize the stakeholder component of the project coupled with insufficient personnel. The latter problem should be resolved by the end of June 2007, its origin is associated with the start date (mid semester) and lack of incoming graduate students in the spring term. Lyda Zambrano, finishing a PhD focused on the use of Bayesian analysis of oil production equipment failure as the basis for decision models will join the project as a postdoctoral researcher and significantly alleviate the personnel shortage. During June, we plan to spend time with industrial representatives surveying active sites in the play (see also task below) to identify existing practices.

Subtask 1.2: Identification of best practices

The US Fish and Wildlife Service had begun a project to create a BMP document for the Fayetteville Shale play prior to the initiation of this project. After our initial contact with USFWS, we (Thoma) were invited to participate on the panel and review the BMP document. This document forms the basis for the remaining work on this task. We have been invited by SEECO to visit a number of their drill sites in the play, and will be planning these during June, 2007.

Task 2: Delineate regulatory and environmental concerns in the region and database development

The definition of this task is closely linked with the USFWS BMP document that has been prepared for the Fayetteville Shale. We are initiating discussions with regulatory and other data managers to implement data sharing that will allow site-specific 'flags' to be generated so

that industrial developers will have an early warning of particularly sensitive locales. One challenge associated with this effort is that information regarding the locations of threatened or endangered species is not (and will not be made) publicly available. Thus we are proposing a 'low level' data sharing in which queries regarding specific proposed drill sites can be flagged with different levels of warning; so while no specific T&E species information will be released, an indication that additional development efforts will be required and that subsequent detailed requests to the Arkansas Natural Heritage Commission will be necessary.

A proposal for extension of this task is to implement a Bayesian approach for recommending BMPs based on site specific information that can be retrieved from existing data sources (like the GeoStor database). This idea was viewed positively from the regulatory community; however, the industrial group still did feel that this would be beneficial. Their argument was that the regulatory process should not be influenced by BMP selection – specifically because implementation of BMPs in Arkansas is not enforceable (unless on federal land or contractually agreed upon in the lease agreement). We propose to prepare a prototype for stakeholder evaluation at the next stakeholder meeting (anticipated early October, 2007)

Task 3: Adapt fate and effects and ecosystem effects models

This task is completely on hold on the basis of feedback from the industrial stakeholders. The initial concern expressed was that any prediction made of the environmental effects (particularly coupled with BMP projections) would lead to a situation where the industry would face negative public perception if the on-site construction did not follow the recommendations of the model. Their concern is based on the fact that they are currently required to perform an on-site survey, using a registered professional surveyor, prior to pad placement or road

construction. The level of accuracy of remotely sensed (ie, most of the publicly available GIS data layers) cannot compare to that of an on-site survey. Given this situation, the concern for negative publicity that could arise if the site specific survey based recommendations are in conflict with the recommendations from the model appears to be a valid one.

Task 4: Update and expand financial impact models.

This task has not been initiated (original schedule for initiation was 7/2007), because it is dependent on the approach taken for the Bayesian analysis, and the ultimate decision regarding fate and effects modeling (which provide the consequences of development actions for which the costs need to be estimated).

Phase 2: Preparation of decision support software tools

In addition to the features proposed, the industrial stakeholders felt that an educational component to the LINGO website would be extremely useful. They have offered to provide in-house training presentations for adaptation. The industry realizes that they do not always have a positive public image with regard to the environment; however, they feel that they are good environmental stewards, and want bothe regulators and the public to know what kinds of activities they commonly implement for environmental protection during exploration and production of natural gas in the Fayetteville Shale Play. We propose to add a section that will meet this need (it was reiterated several times at different meetings and other communications).

We are considering ways to address the industry concerns (as mentioned above) and still provide an effective decision-support system. Our current focus is on assessing the feasibility of building a “fuzzy-logic” system that takes into account the uncertainty associated with the

various GIS layers used as input. So, for example, if a BMP selection depended on the distance to body of water whose location was only known with 90% certainty to be within 75' (this is typical of 1:100,000 scale map layers) of the reported location, the model would propagate this uncertainty into a probability that a particular BMP would be recommended. Only after an on-ground survey could a more precise BMP be chosen. However, providing a range of possible environmental impacts and subsequent BMP prescriptions would help industry and government stake-holders focus on potential drilling areas with the least likelihood of adverse environmental impact. This approach could take the form of a "risk" map showing the probability of a particular adverse impact across the shale.

Task 5: Integrate map products with risk analysis modules

We are currently initiating aspects of this task. Due to some uncertainty associated with stakeholder comments and concerns (as mentioned above), the scope of this task may be altered to more closely match the tools felt to be beneficial. In particular, the stakeholders have indicated that a web based tool for tracking permit applications would be very useful. However, the industrial representatives were sensitive to the possibility that information made public about which leases were in-process (i.e., not yet approved) could compromise their business plan by 'tipping off' their competitors.

In meetings with regulators, it was apparent that there were not always clear lines of communication with regard to the permitting process. A clearing house for information regarding the status of permits was positively received. This is envisioned to provide streamlined communication across agencies and with the industry. It will include a 'permit life cycle' through which users will be guided to follow the appropriate steps necessary for permit

acquisition – there will be decision trees that will aid in determination of which additional regulatory bodies (e.g, US Army Corps of Engineers – via clean water act) may need to be informed of proposed drilling activity.

Overall the project is close to the proposed schedule. Some uncertainties in the regulatory climate and stakeholder concerns have resulted in parts of the project moving more slowly than originally planned. We are moving forward with development of a draft web site that we propose to present to stakeholders in the early Fall 2007.

jeFunding

This project was selected under DOE's Low Impact Natural Gas and Oil solicitation, February 2006.

Anticipated DOE Contribution: $499,582
Performer Contribution: $136,832 (30% of total)

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Appendix A

Overview of Permitting Requirements for Fayetteville Shale Wells

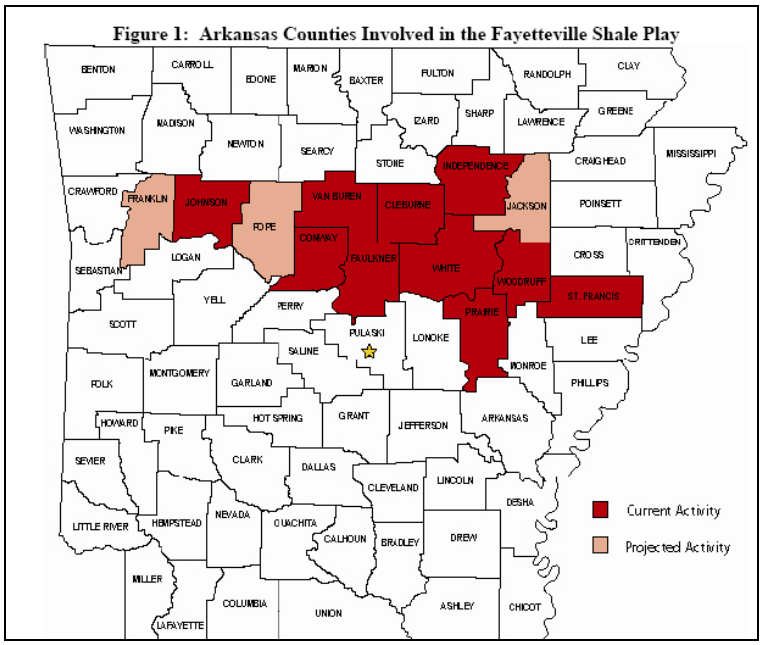
John A. Veil, Argonne National Laboratory

1 INTRODUCTION

1.1 Background

In mid-2006, the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) awarded a contract to the University of Arkansas at Fayetteville (UAF) and Argonne National Laboratory (Argonne)[2] under DOE's Low Impact Natural Gas and Oil (LINGO) program. The contract funded a project titled "Probabilistic Risk Based Decision Support for Oil and Gas Exploration and Production Facilities in Sensitive Ecosystems." The project focuses on the development of natural gas production in the Fayetteville Shale region in Arkansas. Figure 1 shows the counties in Arkansas underlain by the Fayetteville Shale.

[2] Argonne is a U.S. Department of Energy laboratory managed by UChicago Argonne, LLC under contract DE-AC02-06CH11357.



Source: University of Arkansas, 2006

1.2 Purpose of This Document

On October 11, 2006, the project team held a kick-off meeting with stakeholder representatives from government and industry. During the meeting, the group discussed some of the concerns and issues associated with the large scale of drilling and production in the Fayetteville Shale anticipated to occur over the next few years. Following the stakeholder meeting, the project team met to discuss next steps. Most members of the project team have limited experience with regulatory and permitting questions. The project team leader directed Argonne to prepare a summary of the types of permits potentially required of operators planning to explore for and produce natural gas in the Fayetteville Shale.

This document provides an overview of the major state and federal permits that operators must obtain before and during the process of finding and producing natural gas. It is not intended to cover all types of reporting and business transactions that operators must conduct. For example, the Arkansas Oil and Gas Commission (AOGC) imposes various requirements to

conserve the state's oil and gas resources and ensure that proper state taxes are paid. Although these are important to the AOGC's mission and represent responsibilities for operators, they have no immediate topical relevance concerning environmental protection or production in sensitive requirements. Therefore, this overview focuses primarily on permits and other requirements that most directly involve environmental protection concerns.

For purposes of brevity, most of the application and reporting forms are not reproduced here. Instead, URLs for agency websites are provided.

To put the regulatory and permitting requirements in context, Chapter 2 describes the various activities undertaken by oil and gas companies from planning to production. Chapter 3 builds on this framework by identifying the regulatory and permitting requirements that influence each stage. Finally, Chapter 4 discusses the implications of permitting.

2 DESCRIPTION OF THE OIL AND GAS PROCESS

This chapter describes the stages of the oil and gas process. This allows readers a better understanding of how the oil and gas business proceeds. It also identifies the types of environmental issues that could arise at each stage.

2.1 Gaining Access to the Resource

The first step towards producing oil and gas involves gaining access to the property under which the prospective oil and resources are located and on which surface facilities will be located. As a starting point, readers are referred to the informative report "Royalty and Surface Owner Brochure" (AOGC 2005). The brochure is available at: http://www.aogc.state.ar.us/PDF/Royalty%20and%20Surface%20Owner%20Bulletin.pdf.

2.1.1 Mineral Rights

The brochure describes how ownership of some pieces of real estate has been split into surface rights and mineral rights. The mineral rights govern the oil and gas resources beneath the property. Oil and gas companies can obtain access to the resources by purchasing the total property (surface plus mineral rights), by purchasing just the mineral rights, by leasing the mineral rights from the owner of the mineral rights, or by a unit integration process. The latter two approaches are discussed below.

2.1.2 Leasing of Mineral Rights

A mineral lease is a legal binding contract between the mineral rights owner (Lessor) and an individual or company (Lessee) that allows for the exploration and extraction of the minerals covered under the lease. Some of the key elements typically included in a lease are:

- An up-front fee or bonus paid to the Lessor as an inducement to sign the lease,
- The lease term (this can vary depending on when the Lessee begins production and for how long the Lessee continues production),

- A royalty agreement under which the Lessee will pay a portion of the production receipts to the Lessor, and
- An agreement that allows the Lessee access to some portion of the surface lands so the oil and gas can be extracted. Under Arkansas law, mineral rights have priority over surface rights. Property owners who have only surface rights must allow the mineral rights owner or Lessee to have access to a reasonable portion of the land. This agreement is generally reached through the lease, but if the Lessor does not agree, the Lessee can take the matter to court.

2.1.3 The Unit Integration Process

The AOGC establishes drilling units of specified sizes for the purposes of fairly apportioning and conserving the oil and gas produced within the unit. Field rules established by the AOGC for several of the fields in the Fayetteville Shale specify that drilling units must be 640 acres in size. If a mineral rights owner in a drilling unit does not agree to a lease with a prospective Lessee, the oil and gas company can petition the AOGC to grant access to the minerals under an integration order. AOGC (2005) provides greater details on this process.

2.2 Searching for Oil and Gas

Once the oil and gas company has legal access to lands with prospective oil and gas resources, it attempts to identify the optimal well sites within those lands.

2.2.1 Seismic Studies

Frequently, the operator will conduct seismic studies. These involve the detonation of explosive charges to create vibrations and sound waves that move through underground formations. The sound waves are subsequently reflected back to surface receptors. Some of the elements in a seismic study include:

- A preliminary line survey,
- Acquisition of necessary permits,
- Selection and marking of shot-hole locations,
- Necessary clearing of vegetation,

- Shot-hole drilling,
- Implantation of an explosive charge,
- Detonation and backfill of shot-hole.

Geophysical receptor instruments are used to measure the patterns followed by the reflected sound waves as they return to receptors. Computer algorithms help to interpret the shape and characteristics of underground formations.

2.2.2 Exploratory Wells

Company geologists use the results of the seismic studies to predict the optimal locations for siting the wells. In areas with prior established production, exploratory wells are not necessary. However, in some cases, before embarking on a full-scale drilling program, the companies may drill one or a few wells that are used to confirm whether the targeted formations hold economically viable resources.

Drilling an exploratory well uses essentially the same process as drilling a production well. The production well drilling process is described in the next section.

2.3 Drilling Production Wells

When oil and gas companies are confident that they have located economically viable resources, they begin to drill a series of wells that allow access to the portions of the formations where the resources reside. A useful overview of the drilling process is offered through Argonne's Drilling Waste Management Information System (DWMIS) website (http://web.ead.anl.gov/dwm/techdesc/drilling/index.cfm). Portions of that description are excerpted here.

2.3.1 Basics of the Drilling Process

Oil and gas wells are constructed with multiple layers of pipe known as casing. Traditional wells are not drilled from top to bottom at the same diameter but rather in a series of progressively smaller-diameter intervals. The top interval is drilled starting at the surface and has the largest diameter hole. After a suitable depth has been reached, the hole is lined with casing that is slightly smaller than the diameter of the hole. Then cement is pumped into the space between the wall of the drilled hole and the outside of the casing. Next, a smaller diameter hole is drilled to a lower depth. Another casing string is installed to that depth and cemented. This process may be repeated several more times. The final number of casing strings depends on the regulatory requirements in place at that location. It reflects the total depth of the well and the strength and sensitivity of the formations through which the well passes.

Figure 2 shows a cross-section of a well. The well incorporates surface casing plus two additional casing strings set to deeper depths. It also shows the recirculating system of drilling fluid or mud that is used to lubricate the rotating drill bit. Drilling mud is pumped downward through the hollow drill pipe and exits through holes in the bit. The mud helps to convey the ground-up rock (drill cuttings) to the surface through the annular space between the drill pipe and the drilled hole.

At the surface, the mixture of mud and cuttings is passed over a vibrating screen known as a shale shaker. After passing through the screens, the liquid mud is recirculated back to mud tanks where mud is withdrawn for pumping downhole. The drill cuttings remain on top of the shale shaker screens; the vibratory action of the shakers moves the cuttings down the screen and off the end of the shakers to a point where they can be collected and stored in a reserve pit for later disposal.

2.3.2 Directional Drilling

Historically, wells were drilled to be relatively vertical. They were completed at a depth to intersect a single formation. Thus, one full well was required for each completion. Modern technology offers modifications to several aspects of this procedure, thereby allowing more oil and gas production with less drilling and less waste generation. In the mid-1970s, new technologies including steerable downhole motor assemblies and measurement-while-drilling tools became more prevalent and enabled drilling to proceed at angles off of vertical. Drillers could now more easily turn the well bore to reach targets at a horizontal offset from the location of the wellhead. This opened up many new possibilities for improving production. Three variations of drilling to offset targets are shown in Figure 3. They include multi-lateral drilling, horizontal drilling, and directional drilling. (While shown here as a specific case, the term “directional drilling” is typically used for the broad class of drilling to offset targets).

It is likely that some form of directional drilling will be employed in many wells drilled in the Fayetteville Shale.

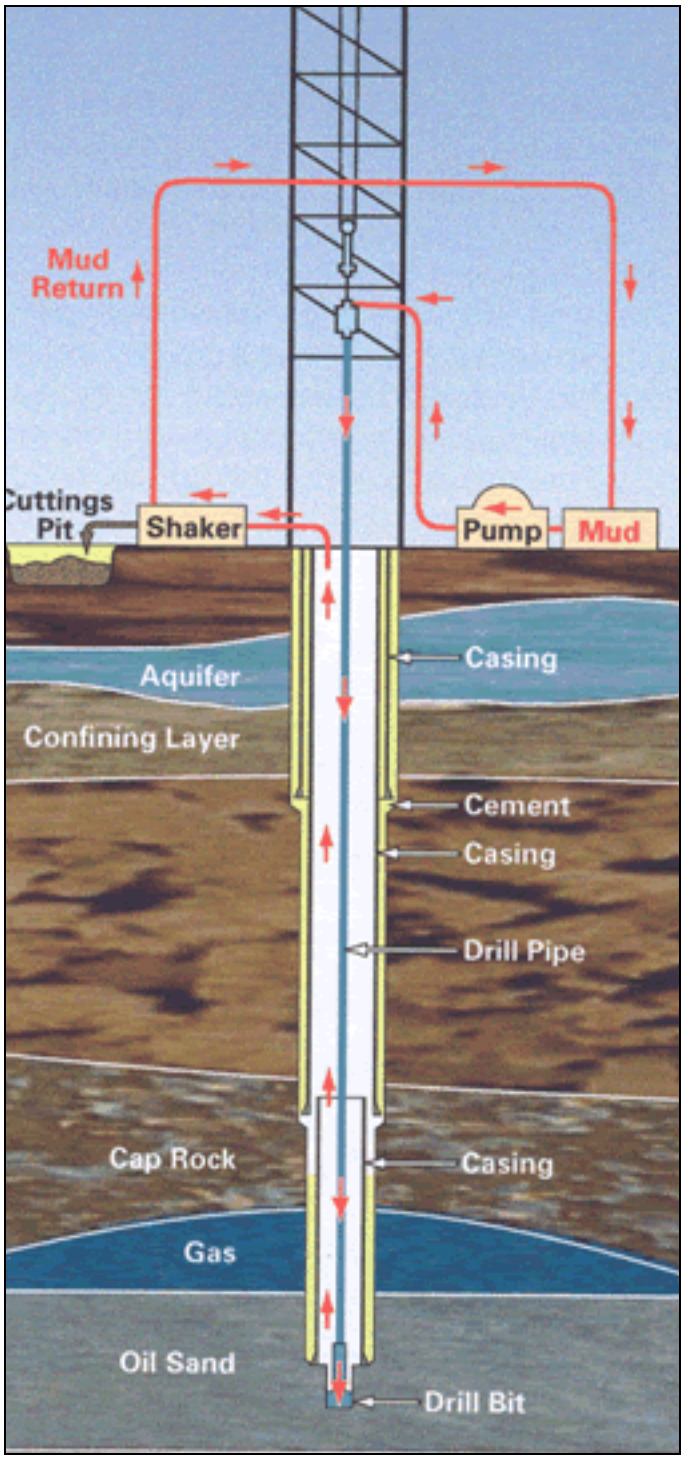


Figure 2 – Cross-section of a Typical Well

Source: Argonne, DWMIS website

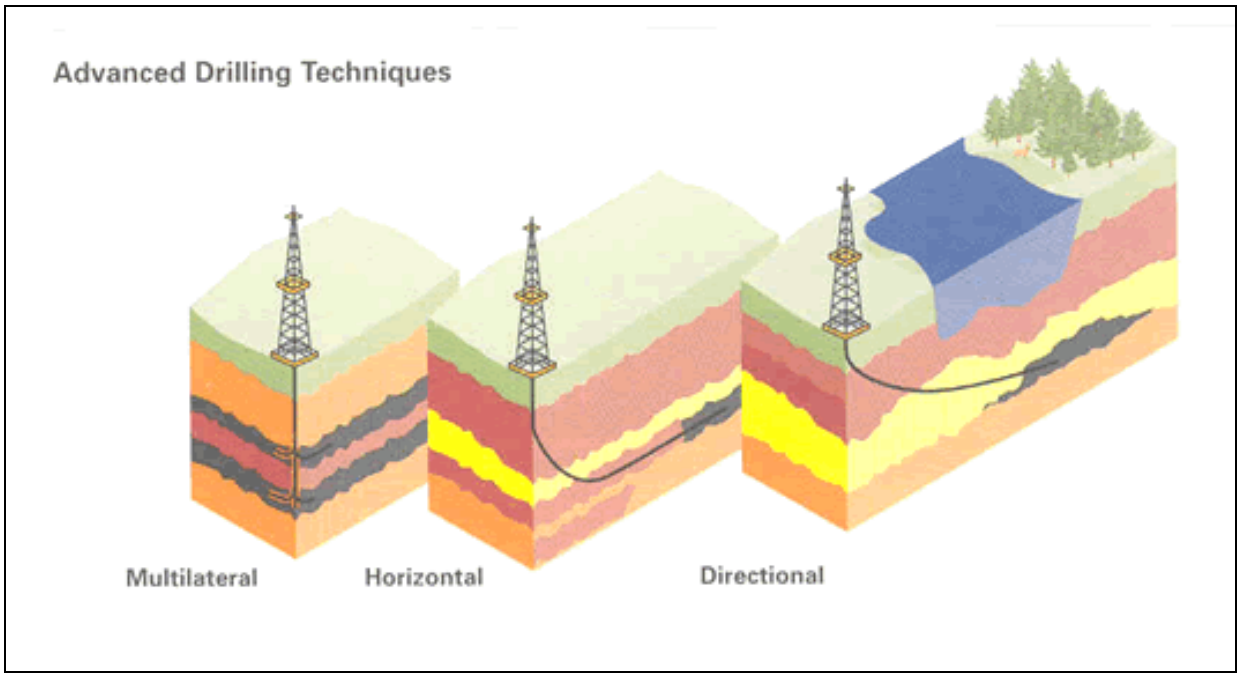


Figure 3 – Forms of Directional Drilling

Source: DOE 1999

2.4 Preparing Wells to Begin Production

A newly drilled well must be properly completed to allow for oil and gas to enter the well and move to the surface. This involves adding equipment and monitoring devices that allow the well to function and creating pathways for oil and gas to move from the formation into the well.

2.4.1 Well Completion

Oil and gas are not produced from a newly drilled well until the well is configured for operations. The bottom of the well ends either in open rock in the target formation or in casing. In the former case, the formation is already accessible to the well. However, in a well that is cased through the target formation, openings in the casing must be made to allow the oil and gas access to enter the well. Perforations (or perfs) are created using controlled explosive

charges that are lowered to the desired depth on a cable. If necessary, the producing formation is prepared to enhance flow by hydraulic fracturing. This is described in the following section.

Next, small diameter pipe called tubing is lowered into the well to the depth at which fluids are accumulated. Near the bottom of the tubing, a packer is installed. The packer looks like a large donut that fills the space between the tubing and the next layer of casing. This configuration creates a tight seal. Completion fluid is added to the annular space above the packer and between the tubing and casing to prevent corrosion. In wells that require pumping to bring oil, gas, and water to the surface, a pump is attached to the bottom of the tubing string. Pressure and temperature monitoring sensors may also be installed at the bottom of the well.

2.4.2 Hydraulic Fracturing

A newly completed well is able to collect oil, gas, and water from a limited radius around the well perforations. Operators often stimulate the surrounding formation to enhance flow rate and expand the radius. This type of stimulation is known as hydraulic fracturing (also known as a frac job). Service companies inject large volumes of fracturing fluid into the formation. Pressure is increased until cracks or fractures form. The fracturing fluid also contains sand or other small hard particles (proppants) that move into the newly created fractures. After a few hours, the pressure is gradually dropped and the fracturing fluid is removed from the well. The proppants remain in the fractures and keep the fractures open to allow better fluid flow into the well.

2.5 Production

After the well is completed, the operator can begin producing the fluids from the well. Depending on the formation, combinations of crude oil, natural gas, and formation water (produced water) enter the well bore. The fluids flow to the surface either by natural pressure or pumping. Various treatment and separation steps are undertaken to obtain discrete oil, gas, and water streams. The oil and gas are collected through a series of gathering lines and may be stored in tanks. Additional processing of the oil and gas can be undertaken in the field, or the products can be transported offsite.

At most onshore locations, produced water is reinjected into underground formations. Some injection is conducted into producing formations to maintain reservoir pressure. In other areas, injection operations target nonproducing formations for disposal. Operators install their own injection wells as part of a producing field or they transport produced water to an offsite commercial disposal facility.

2.6 Transportation and Processing

The separated products then leave the field. Oil is transported to refineries by pipeline or by truck. Gas is transported by pipeline to natural gas processing plants.

Although these steps are important to the industry, they are distinct from the oil and gas production process. Typically these steps are conducted by different companies from the ones that produce the oil and gas. These activities are not discussed further in this report.

2.7 Closure of Wells No Longer in Service

All wells have a finite service life. In some cases, newly drilled wells prove to be non-productive. Other wells produce for months to years, but eventually become no longer profitable. Each well bore represents a potential conduit between producing formations, the surface, and intermediate layers (including drinking water aquifers). Proper closure of wells no longer in service avoids leakage or unanticipated movement of fluids to inappropriate locations. This is accomplished by plugging the entire well or key portions of the well with cement or other substances. The process is known as plugging and abandonment (P&A).

3 KEY REGULATORY REQUIREMENTS AFFECTING THE OIL AND GAS PROCESS

This chapter identifies the pertinent regulatory requirements for each stage of the oil and gas process described in Chapter 2. Links are provided to agency websites that enable the reader to access and view original forms and regulatory source texts. Throughout this chapter, relevant permits or regulatory requirements of state and federal agencies other than the AOGC are identified as appropriate.

Appendix A contains completed applications and forms for an actual well in the Fayetteville Shale. An interactive map showing all completed wells in the Fayetteville Shale is available at: Geostor. When users click on a well location, detailed well information is displayed for the particular site.

3.1 AOGC Responsibilities

The AOGC administers the oil and gas regulations. It has the responsibility to prevent waste, encourage conservation, and protect the correlative rights of ownership associated with the production of oil, natural gas, brine, and associated products. The statewide regulations of the AOGC can be found in Commission Rules and Regulations, which are available at: AOGC Online Forms. Much of the discussion in this chapter is based on those rules and regulations.

In addition to adopting general regulations that apply throughout the state, AOGC can be petitioned to develop field rules and regulations for any new reservoir or pool within six months after the initial completion of the discovery well or the drilling of three wells penetrating the same pool or reservoir, whichever occurs first (Rule B-38). The AOGC's website lists the field rules for four fields in the Fayetteville Shale Play (Cove Creek, Griffin Mountain,

Gravel Hill, and Scotland) at AOGC Fayetteville Shale Field Rules. The field rules establish guidelines for the size of drilling units, well locations (including setback and separation distances), well construction, reporting, and other items.

3.2 Gaining Access to the Resource

3.2.1 Leasing

Leasing is not directly regulated by the AOGC. In legal terms, leases are contracts between oil and gas companies and property owners. The Arkansas Leasing Manual (Morgan 2005) offers detailed information covering leasing as it applies to Arkansas. The manual is available in available at: AOGC Leasing Manual.

3.2.2 Unit Integration

When more than one operator or mineral rights owner have access to the oil and gas resources within a drilling unit (often a 640-acre area), they can agree among themselves to integrate their production operations and share revenues. However, if they are unable to find agreement, the AOGC can require integration, and establish guidelines for the sharing of revenues among all parties.

The process begins by the oil and gas operator filing an application to AOGC to grant access to the minerals under an integration order. The applications received by the AOGC can be viewed at: http://www.aogc.state.ar.us/Current_Hearing_Apps.htm.

After holding a hearing, the AOGC decides whether or not to grant the integration application. It also determines the terms and royalties that should be granted to the unleased

mineral rights owners. The procedures for filing applications and the schedule for hearings in 2007 are available at: http://www.aogc.state.ar.us/Hearing%20Schedule%202007.pdf.

If an Integration Order is granted, the unleased mineral rights owners are given various options for integration of the unleased interests. The recent Integration Orders can be viewed at: http://www.aogc.state.ar.us/Oct_2006_Hearing_Orders.htm.

3.3 Searching for Oil and Gas

AOGC's seismic rules and regulations are contained in AOGC Rule B-42. Operators seeking to conduct seismic studies must file an application with the AOGC. Form 19 - Application for Permit to Conduct Seismic Studies can be viewed at: AOGC Seismic Application. The application package includes various pieces of information:

- Where will the studies be conducted;
- How many shot holes will be used;
- What amount of explosives will be employed; and
- When will the studies be undertaken.

Along with the application, the operator must provide a surety bond to the AOGC. Bonds are held open by the AOGC until seismic studies are completed, and eventual damages have been settled.

3.4 Siting and Drilling Wells

Several of the AOGC's Rules govern well drilling activities. Rule B-1 requires that operators file Form 2 - Notice of Intention to Drill for Oil and Gas, available at: Notice of Intent. The application must include information pertaining to the surface location of the wellhead, the

distance from the lease or property boundaries, and the underground location of the target formation. Operators must also file proof of financial responsibility (AOGCC Rule B-2).

The spacing of wells is governed by AOGCC Rule B-3; however, those requirements are superseded by field rules, when issued. During the drilling process, the driller must keep adequate records. Those can become part of the Well Completion Report (described in Section 3.6).

Several rules and regulations provide requirements for the components used to construct the well. AOGC Rule B-14 covers surface equipment, including valves, gauges, and meters. AOGC Rule B-15 outlines the general requirements for the types and amounts of casing to be used in constructing the well. Finally, AOGC Rule B-16 requires installation of blow-out preventers.

3.5 Management of Drilling Wastes and Reserve Pit

Jurisdiction over the reserve pit is shared between the AOGC and the Arkansas Department of Environmental Quality (ADEQ). In addition, the Arkansas Department of Health and Human Services (ADHHS) has the opportunity to review and comment on reserve pit applications. The requirements imposed by each agency are described below.

3.5.1 AOGC Requirements

The AOGC has published the Requirements for Pumping Reserve Pits into Wells at the end of the General Rules and Regulations. Operators must file Form 20 - Request for Disposal of Reserve Pit Fluids, available at:

(http://www.aogc.state.ar.us/OnlineData/Forms/Form%2020%20-%20Request%20for%20Disposal%20of%20Reserve%20Pit%20Fluids.pdf).

3.5.2 ADEQ Requirements

The requirements for constructing and emptying reserve pits are provided in ADEQ's Oilfield Waste and Reserve Pit Requirements. This short document, along with a cover memo from the ADEQ, are available on AOGC's website at: http://www.aogc.state.ar.us/PDF/ADEQ%20-%20Reserve%20Pit%20&%20Storm%20Water%20Requirements.pdf.

Before beginning construction and drilling activities, operators must provide information to ADEQ covering the location and characteristics of the drill site. The ADEQ then issues a letter of authorization for construction, operation, and closure of the reserve pit. At the end of drilling operations, the reserve pit fluids must be properly disposed of, and the operator must file a Disposition of Oilfield Waste Form with the ADEQ.

3.5.3 ADHHS Requirements

The ADHHS reviews the application forms filed with the AOGC. The agency then makes a determination whether the proposed location is in the watershed of a current drinking water supply. The ADHHS then issues an authorization to construct and operate a reserve pit. The authorization may include requirements relating to liner construction.

3.5.4 Actual Practices

In a national survey covering commercial oil field waste disposal, Puder and Veil (2006) interviewed state officials in many states to learn what oil and gas operators are actually doing with their drilling wastes. They report for Arkansas:

> "In general, drilling fluids and muds are collected in temporary pits (reserve pits) at each well site. These fluids are then hauled to one of five permitted land application facilities in Arkansas. These facilities have aboveground pits for the collection of produced water and mud. Once the fluids and muds have separated, the muds are spread onto designated fields; then depending on their permits, management activities such as tilling into the soil and revegetating must occur. Routine sampling of these fields is also required. The remaining water is either pumped to tanks for injection into wells (Class II under the authority of the Arkansas Oil and Gas Commission) or hauled to one of these facilities with a commercial Class II well. These are the only current options for disposal of muds. Alternative methods, such as onsite disposal in the reserve pits or application to another site, are considered on a case-by-case basis but rarely have been authorized in the past."

3.6 Well Completion

Several of the AOGC's rules and regulations govern well completion activities. AOGC Rule B-23 requires the installation of tubing in wells -- except for dry gas wells that have appropriate surface casing. According to AOGC Rule B-24, chokes must be installed. AOGC Rule B-25 prescribes that all flowing wells must be produced through oil/gas separators.

AOGC Rule B-5 requires that following completion of a well, the operator must submit a Well Completion Report using Form 3 - Producer's Well Completion and Recompletion Report, available at: AOGC Well Completion Report. The form includes information describing well construction, logging results, and hydraulic fracturing or other stimulation activities.

3.7 Oil and Gas Production

The operator must obtain a Certificate of Compliance from the AOGC before any production can occur. Form 4 - Request for Certificate of Compliance, Notice of Commencement of Production, or Change of Purchaser is available at: Producer Certificate.

AOGC Rules D-1 through D-19 provide specific requirements governing gas production. Likewise, the AOGC website Forms page (http://www.aogc.state.ar.us/aogcforms.htm) lists numerous forms that are used to report monthly production figures. In light of their more limited environmental emphasis these items are not discussed further here.

The ADEQ issues National Pollutant Discharge Elimination System (NPDES) permits for discharges to surface waters. With the exception of stormwater runoff, the activities described in Chapter 2 are not expected to create surface water discharges. The federal Energy Policy Act of 2005 provides an exemption from stormwater runoff permits for construction activities at oil and gas facilities that disturb less than 5 acres of land. Presumably, all or most oil and gas sites in the Fayetteville Shale area will be sized to disturb less than 5 acres of land. Therefore, NPDES permit requirements are not likely to be triggered. However, producers are not exempt from the requirements to implement BMPs to mitigate sediment runoff from these construction sites.

3.8 Management of Produced Water

Jurisdiction over produced water (also referred to as brine or salt water) is shared between the AOGC and the ADEQ. The following sections describe the requirements imposed by each agency.

3.8.1 Underground Injection

The AOGC website provides a link to the joint AOGC/ADEQ Form - Application to Inject Salt Water/Enhanced Recovery Fluid, available at: http://www.aogc.state.ar.us/OnlineData/Forms/(.208)%20SWD%20Application.pdf. The application form explains that if the injection is being made for enhanced recovery, only the AOGC is involved. Operators must file monthly produced water injection reports using Form 14 Saltwater Disposal Report, available at: http://www.aogc.state.ar.us/OnlineData/Forms/Form%2014%20-%20Salt%20Water%20Disposal%20Report.pdf).

The ADEQ website does not discuss permitting for Class II injection wells in general. However, the Arkansas Underground Injection Control Code promulgated by the Arkansas Pollution Control and Ecology Commission in Regulation 17 states that the AOGC exercises responsibility for Class II injection wells. This regulation can be accessed from the list of regulations at: http://www.adeq.state.ar.us/regs/default.htm.

3.8.2 Other Produced Water Requirements

The discharge of any fluids generated from any activity associated with oil and gas exploration or production to any surface or ground waters of the State is strictly prohibited. This includes produced water. However, the ADEQ has the responsibility for regulating the

construction and operation of surface facilities associated with a disposal system for injection of saltwater. The ADEQ uses a general permit format. The original general permit has expired. The latest draft version of the proposed new general permit "Authorization to Construct and Operate the Surface Facilities Associated with a Disposal System for Injection of Saltwater" can be viewed at: http://www.adeq.state.ar.us/water/branch_permits/pdfs/0000-WG-SW_draft.pdf. The application to be covered under the general permit "Notice of Intent Application for Saltwater Disposal Permit" is available at: http://www.adeq.state.ar.us/water/branch_permits/pdfs_forms/swdnoi.pdf.

3.9 Plugging and Abandonment

AOGC Rule B-8 describes the locations and size of plugs for abandoning wells. Rule B-8 offers additional requirements for the plugging of core holes from seismic studies. Prior to starting the plugging process, operators must file Form 11 - Application to Plug, available at: http://www.aogc.state.ar.us/OnlineData/Forms/Form%2011%20-%20Application%20to%20Plug.pdf). A representative of the AOGC will be onsite to witness the plugging and will complete a plugging record form.

3.10 Endangered Species Act Considerations

The federal Endangered Species Act entrusts the U.S. Fish and Wildlife Service (USFWS) with consultation authorities and responsibilities. According to Chris Davidson of the USFWS Arkansas Office[3]:

> "Any activity with a federal nexus (i.e., issuance of permits such as NPDES, Stormwater, Corps 401/404 and Section 10, etc) requires some level of consultation under section 7 of the ESA with us. A federal nexus exists anytime an activity is funded, authorized, or carried out by a federal agency. This nexus extends to any permit issued by a federal agency and often times state agencies if their program is partially funded or authorized by a federal agency such as EPA. FWS comments are required for NPDES and Stormwater permits issued by ADEQ and Corps 401/404/section 10 permits."

In June 2006, the Arkansas Office of the USFWS proposed draft best management practices for oil and gas operations in the Fayetteville Shale for protection of wildlife and plants. However, at this time, these are not mandatory.

3.11 Other Environmental Permits Not Included

Most oil and gas sites are subject to various other local or state regulatory permitting requirements that have not been included here in order to complete the first draft of this report quickly. They may be the subject of further investigations.

Examples of such requirements include:

- air quality permits,
- noise control restrictions,
- construction permits, and
- wetlands permits.

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[3] Electronic mail from Chris Davidson, USFWS, to John Veil, Argonne National Laboratory, November 1, 2006.

4 Implications of Permitting

Chapter 3 describes many types of permits that oil and gas operators must obtain, and other regulatory requirements they must follow. Some of these permits are sequentially linked as shown in the documentation for an actual Fayetteville Shale well (Appendix A). The steps involved in receiving approval to drill and produce from the well are shown below. The dates on which each step was completed are indicated in parentheses.

1. The operator files Form 2 – Notice of Intention to Drill for Oil and Gas (8/23/05).
2. AOGC issues a Permit to Drill (8/29/05).
3. ADHHS grants approval to construct a reserve pit (9/12/06).
4. The operator drills the well (2/6/06 – 3/15/06).
5. The operator files a Form 3 - Well Completion and Recompletion Report (3/20/06).
6. The operator files a Form 4 - Request for Certification of Compliance, Notice of Commencement of Production, or Change of Purchaser (3/20/06).
7. Certificate of Compliance approved (3/21/06).

Operators try to develop project schedules that allow them to coordinate the various steps of the oil and gas process. Some of the key steps are:

- Leasing,
- The availability of service companies to conduct seismic studies,
- Construction of the reserve pit and drilling site,
- The availability of drilling rigs,
- The availability of service companies to conduct well construction, completion, and frac jobs, and
- Construction of field gathering lines to move the gas offsite.

In the example shown above, regulatory approvals were granted soon after the applications and requests were made. Permits are not always obtained this easily or quickly, however. If any step of the schedule is delayed, the timing of the remaining steps can be uncertain. The availability of equipment and contractor support is a very real issue that faces operators, particularly when interest in oil and gas exploration and production is heightened in a region, such as is anticipated for the Fayetteville Shale. Drilling rigs are often scheduled weeks to months in advance. If a permit is delayed by three weeks, for example, it is conceivable that the planned drilling rig will have moved to a new location, and the operator will have to reschedule.

Some of the factors that could cause delays or bottlenecks in the process include:

- Increased workload on AOGC and ADEQ staff because of a large increase in applications,
- Institution of new tiers of requirements, such as the draft USFWS best management practices, that could narrow the windows of opportunity for drilling to occur,
- Shortage of equipment and qualified contractors caused by high demand for those items.

As the UAF/Argonne team moves forward with its project, it is important to keep permitting and scheduling issues in mind. The project team's goal is to improve the process both for environmental protection and for the industry's ability to expeditiously produce oil and gas resources.

5 References

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Appendix A – Well Records from AOGC Database for A Well in the Fayetteville Shale

See separate .pdf file.