

pipelines to be buried using the double ditch method. *See* Exhibit B, pg. 5.

4.

Attached herewith as Exhibit C is a true and correct copy of a document titled, “North Dakota Oil & Gas Leasing Considerations” by Ron Anderson. This document recommends that surface owners direct oil and gas companies to use the double ditch method in areas where pipelines are installed in lands to be cultivated or grazed. *See* Exhibit C, recommendation 4.

5.

Attached herewith as Exhibit D is a true and correct copy of the Minnesota Environmental Quality Board Findings of Fact, Conclusions, and Order regarding MEQB Docket No. 03-62-PRP-MnSP. This Order states the double ditch method minimizes the mixing of topsoil and subsoil when a trench is excavated for a pipeline. *See* Exhibit D, pg. 9 paragraph 51.

6.

Attached herewith as Exhibit E is a true and correct copy of a document titled “Hints on Negotiating An Oil and Gas Lease,” by Judon Fambrough, which provides information to non-experts on oil and gas lease provisions. This document suggests that mineral owners who want to cultivate or graze the area above a pipeline should require the lessee to use the double ditch method. *See* Exhibit E, pg. 2.

7.

Attached herewith as Exhibit F is a true and correct copy of an article titled “Negotiating Oil and Gas Leases on Pennsylvania Farmland” issued by the Pennsylvania Department of Agriculture. This article recommends that landowners require pipelines to be installed using the double ditch method. *See* Exhibit F, pg. 12 provision b.

PUBLIC SERVICE COMMISSION

STATE OF NORTH DAKOTA

**Dakota Gasification Company
CO₂ Pipeline Siting Application**

CASE NO. PU-07-184

FINDINGS OF FACT, CONCLUSION OF LAW, AND ORDER

June 27, 2007

Appearances

Commissioners Susan E. Wefald, Tony Clark, and Kevin Cramer.

Mark D. Foss, Dakota Gasification Company, 1600 East Interstate Avenue, Bismarck, North Dakota 58503, on behalf of Dakota Gasification Company.

Annette Bendish, Public Utility Analyst, Public Service Commission, 600 East Boulevard Avenue, Bismarck, North Dakota 58505-0480, on behalf of the Public Service Commission.

William W. Binek, Commission Counsel, Public Service Commission, 600 East Boulevard Avenue, Bismarck, North Dakota 58505-0480, as the Hearing Officer.

Preliminary Statement

On May 11, 2007, Dakota Gasification Company (DGC) filed an application for a route permit authorizing construction of approximately 11,400 feet of 14-inch pipeline to transport CO₂ produced at the Great Plains Synfuels Plant to the oil-producing areas in southeastern Saskatchewan. The proposed construction will be across Lake Sakakawea from McKenzie County to Williams County, North Dakota and will replace the existing pipeline.

On May 16, 2007, the Commission deemed the application complete and issued a Notice of Filing and Notice of Hearing.

The Notice of Hearing identified the following issues:

1. Will the location, construction and operation of the proposed pipeline produce minimal adverse effects on the environment, natural resources and upon the welfare of the citizens of North Dakota?

2. Is the proposed pipeline compatible with the environmental preservation and the efficient use of resources?
3. Will the proposed pipeline corridor minimize adverse human and environmental impact while ensuring continuing system reliability and integrity and ensuring that energy needs are met and fulfilled in an orderly and timely fashion?
4. Is it appropriate for the Commission to waive any procedures and time schedules as requested in the application?

The Commission held a public hearing on Tuesday, June 12, 2007 at 11:00 a.m. (CDT) at the Watford City Hall, 213 2nd Street, Watford City, North Dakota.

DGC supplemented the record with late filed exhibits responding to questions raised by the Commission at the hearing.

Having allowed all interested persons an opportunity to be heard and having heard, reviewed and considered all testimony and evidence presented, the Commission makes the following:

Findings of Fact

1. Dakota Gasification Company is a wholly owned subsidiary of Basin Electric Power Cooperative. DGC, a North Dakota corporation, owns and operates the Great Plains Synfuels Plant, which is located near Beulah, North Dakota.
2. The synfuels plant is a coal gasification plant that uses a Lurgi coal gasification process to gasify lignite coal into gases and liquids. The plant consumes approximately 17,000 tons of lignite per day. When production is dedicated to synthetic gas production, the plant produces approximately 160 million standard cubic feet per day (mmscf/d) of synthetic natural gas. As byproducts, the plant produces a combination of krypton/xenon gas, liquid nitrogen, cresylic acid, phenol, ammonium sulfate and carbon dioxide. As a co-product, the plant is capable of producing up to 1,200 tons of anhydrous ammonia per day.
3. DGC witness Robert Weir, project manager for DGC, testified that carbon dioxide is recovered at the synfuels plant using a Rectisol process that captures carbon dioxide with a purity of 95%. The carbon dioxide is compressed using three identical MAN Turbo AG compressors in parallel. These 19,500 horsepower compressors increase the carbon dioxide pressure from about 7 pounds per square inch gauge (psig) to nearly 2,700 psig. Each compressor has a flow capability of 57 mmscf/d. The synfuels plant currently captures approximately 49% of the carbon dioxide it previously emitted to the atmosphere.

4. DGC sells the compressed carbon dioxide to two companies in Saskatchewan: EnCana Oil & Gas Partnership and Apache Canada, Ltd., which use this carbon dioxide for enhanced oil recovery (EOR) at their Weyburn oil field and Midale oil field, respectively.
5. DGC owns and operates a pipeline that delivers the compressed carbon dioxide from the Great Plains Synfuels Plant to the U.S./Canadian border where the pipeline interconnects with the Souris Valley Pipeline. The Souris Valley Pipeline is a pipeline owned by Souris Valley Pipeline Limited, a company organized under the laws of Canada and a wholly owned subsidiary of DGC. The Souris Valley Pipeline is operated by DGC.
6. Weir stated the pipelines traverse approximately 167 miles in North Dakota and extend 38 miles in Saskatchewan, Canada, for a total length of 205 miles. Compressor stations at the Synfuels Plant-site and Tioga, North Dakota are used to boost the pressure of the carbon dioxide to approximately 2,700 psig to ensure delivery to the Weyburn and Midale oil fields at the contractually specified minimum of 2,200 psig. The pipeline is constructed of steel. The segment from the Synfuels Plant to the Tioga, North Dakota area consists of 14-inch diameter outside pipeline. The segment from Tioga to the U.S./Canadian border and continuing to the delivery point at the Weyburn and Midale oil fields consists of 12-inch nominal diameter pipeline. The pipeline passes through the heart of North Dakota oil country and is nearby significant oil fields in Montana. Eleven tap points were installed on the pipeline. These taps would allow take-off of carbon dioxide from the pipeline for a potential customer or customers without forcing a shutdown of the pipeline. The first tap is located near Killdeer, North Dakota and the last tap is located in Canada. The remaining taps are interspersed from the Little Missouri River to the North Dakota/Saskatchewan border.
7. Weir testified DGC has determined that it would be prudent to improve the pipeline's crossing of Lake Sakakawea. Given the protracted drought conditions in the Upper Missouri River watershed, coupled with the management of the reservoir by the United States Corps of Engineers (COE), the level of the reservoir has dropped 30 feet since the pipeline was installed in the year 1999. Specifically, DGC is concerned the pipeline may become exposed and could become a hazard to the public.
8. The construction right-of-way (ROW) width will be 200 feet for the lake crossing. Staging areas on either side of the lake will be required for construction. DGC will use existing roads to access the construction ROW and staging areas. The permanent ROW width will be 50 feet.
9. To reduce any risks associated with the integrity of the pipeline at the lake crossing, DGC will locate the replacement pipeline 100 feet west of the existing line and provide six feet of cover. Once the new line is in place, the abandoned portion of the line will be removed from the lake.

10. Weir explained that the "controlled depth tow" method of construction will be used where pipe sections are welded on-shore and pulled into place. (DGC's application had stated it would use the "lay barge" method.) Heavy equipment to be used in the excavation activities for the lake crossing will consist of a barge-mounted dragline, towboat, anchor/fuel barge and hydrographic survey boat. The trench will be excavated in the lake bottom to provide six feet of cover. Centerline alignment of the trench will be monitored using a shore-based electronic measuring device. The trench depth will be checked using hydrographic surveying equipment. During excavation, 200 feet of silt curtain will be placed on each side of the excavation/soil storage area to mitigate the movement of silt. The materials to be excavated will comprise approximately 78,000 cubic yards, based on a four-foot wide trench bottom, 2.5:1 side slope, eight-foot trench depth and a length of 11,000 feet. The material will be placed on the west side of the excavation. Once the pipe is in place on the trench bottom, excavated material will be returned to the trench in "plugs" spaced approximately 250 feet apart. The plugs are for fixing the pipe in proper orientation and to prevent movement or displacement during subsequent backfilling operations. The trench will then be backfilled using the excavated spoil material. Once the new line is backfilled, the abandoned portion of the pipeline (11,400 feet) will be pulled from the lake with the use of a 100-ton winch.

11. The pipe size, material and thickness will be the same as the current lake crossing, 0.500-inch wall bevel end 14 inches API 5L Gr. X65 seamless pipe. All pipe and field joints will be coated with fusion bonded epoxy (16 mils), and abrasion resistant epoxy (44 mils) and a two-inch concrete jacket weight coating. Field welds will be 100 percent radio graphed. The pipeline will be hydrostatically tested in accordance with applicable regulations to establish the maximum allowable operating pressure of 2,700 psig. Testing will be conducted for a minimum of eight hours (DGC's application had stated 24 hours) and will include a leak test.

12. The line will be located 100 feet to the west of the existing line and have a minimum cover in the lakebed of six feet. The length of replacement line will be approximately 11,400 feet and will be tied into the existing line with four 45° elbows as indicated in Figure 1.1 to DGC's application.

13. The stream is not 100% carbon dioxide. As outlined in Table 1-1 of DGC's application, the typical analysis of the stream is a composition of 95.95% of carbon dioxide.

14. On average, the stream contains approximately 0.80% hydrogen sulfide, but the hydrogen sulfide content from time-to-time may jump to a maximum as high as 2%.

15. The balance of the stream is made up of very small percentages of various hydrocarbons such as ethane, methane, propane, ethylene and various types of butane. Prior to DGC's diverting, compressing, transporting and selling this stream for EOR, this stream was combusted in the boilers at the synfuels plant. While the percentage of

hydrocarbons is quite small, given the large volume of the stream, it was economic to use this stream for these hydrocarbons.

16. DGC witness Rick Nelson, senior environmental engineer, testified that the pipeline and associated facilities are designed, constructed, operated and maintained in strict accordance with the requirements of the U.S. Department of Transportation Pipeline Safety Regulations Code of Federal Regulations (CFR) Title 49, Part 195, Transportation of Hazardous Liquids by Pipeline, as well as other applicable codes, regulations and standards in the United States and Canada.

17. Nelson stated that for the initial lake crossing, the pipeline was trenched with a minimum cover of four feet to a lake bottom elevation of 1,805 feet. Below elevation 1,805, the line was laid on the bottom of the lake. Since the installation of the pipeline crossing in 1999, the lake level has dropped approximately 30 feet.

18. DGC applied for approval from the United States Corps of Engineers on April 20, 2007. DGC filed a Consolidated Application for a Certificate of Corridor Compatibility and Route Permit in this proceeding on May 11, 2007. The acquisition of rights to use the temporary lay-down area, which is owned by the North Dakota School Lands Trust, is scheduled to be completed before July 2, 2007. Assuming DGC has the necessary approvals, construction would commence on July 9, 2007. If construction is started on July 9, the project is scheduled to be completed on October 12, 2007; testing would occur on October 15, 2007; and the project would be placed in service on October 17, 2007.

19. Nelson testified sensitive plant and wildlife potentially affected by the project were evaluated. Information related to sensitive species was obtained from several agencies including the U.S. Fish & Wildlife Service (USFWS), North Dakota Game & Fish Department and the U.S. Army Corps of Engineers. Sensitive species potentially present along or near the proposed route include the interior least tern and piping plover. The tern and plover are known to nest and raise young on sandbars and along sparsely vegetated beaches of Lake Sakakawea; however, no active nesting has been documented near the proposed pipeline crossing at Lake Sakakawea.

The pallid sturgeon is the only endangered fish species with potential for aquatic habitats crossed by Lake Sakakawea. The construction schedule DGC has proposed for this Lake Sakakawea crossing (mid-July to late October) will avoid the spawning periods of the pallid sturgeon.

20. No cultural resource studies were performed for this reconstruction project. However, Class I and Class III Cultural Resources Inventory Reports were submitted and approved by the State Historical Society when the pipeline crossing was initially installed. A copy of the Class III Cultural Resource Management Report for the Lake Crossing Area was included as Attachment 1 to DGC's application. This report inventoried cultural resources within the one-mile corridor on U.S. Army Corps of Engineers land in McKenzie and Williams Counties. Figure 1.1 of the Attachment

showed the location of each site within the corridor. Site 32WI305 is the closest site but east of the existing pipeline and should not be impacted by any construction. Site 32MZ151 located on the south bank of Lake Sakakawea near the pipeline is the only site which could be potentially impacted from this project. Based on a preliminary review, the ROW for the pipeline crossing will be at least 200 feet away from this site. To ensure the site is not disturbed, the area will be marked prior to any construction activities.

21. There are no other economical means of delivering carbon dioxide to our EOR customers.

22. DGC's latest Ten-Year Plan was filed with the Commission on November 14, 2006. Nelson testified this Lake Sakakawea reconstruction project was not included in DGC's Ten-Year Plan as DGC was hoping that the snow pack in the Upper Missouri Basin watershed would be average, above average or sufficient such that this replacement would not be necessary. Notwithstanding, obviously DGC's Ten-Year Plan included the existing pipeline crossing of Lake Sakakawea.

23. The proposed pipeline corridor/route is a 1.0 by 2.7 mile area and lies within both McKenzie and Williams Counties in northwestern North Dakota.

24. Nelson testified that DGC has adopted DGC Board Policy Number 11. This Board Policy commits DGC to compliance with federal, state and local health and safety regulations, as well as establishing a strong safety and health program in order to ensure a safe and healthy work place for its employees.

25. Nelson testified that DGC has adopted DGC Board Policy Number 12. In addition to committing DGC to compliance with federal, state and local environmental regulations, this policy recognizes the need to maintain a healthy environment for the benefit of both DGC's employees and the members of the community in the areas surrounding DGC's facilities.

26. When the pipeline was initially permitted, separate Environmental Assessments (EAs) were prepared for the U.S. Forest Service (USFS) and the Bureau of Land Management (BLM) to address the federal lands crossed by the then-proposed route in compliance with the National Environmental Policy Act. In addition, a Section 404/10 Permit application was submitted to the U.S. Army Corps of Engineers for waters of the United States of America (e.g. Lake Sakakawea).

27. The pipeline system has been studied to determine the effectiveness of pipeline safety systems including leak/rupture detection and automatic block valve closure at approximately 14 locations along the pipeline route. Safety systems are designed to mitigate the potential effects of releases from the pipeline by limiting the amount of pipeline product that can be released into the atmosphere in the event of an accidental release.

28. Pipeline safety system evaluations have been conducted; this involved the determination of pipeline safety effectiveness relative to simulations of potential pipeline releases. Through the results of the accidental release simulations, DGC was able to document the effectiveness of pipeline safety systems and enhance the safety of the public and workers.

29. The North Dakota Natural Heritage Inventory also provided database information regarding threatened, endangered, federal candidate and state sensitive plant species. Information related to sensitive plants and animals was also obtained from published and unpublished literature and through consultation with the USFWS, North Dakota Game and Fish Department, USFS and BLM.

30. A telemetry (SCADA) system provides 24-hour monitoring of the pipeline and compressor operations, including pressures, temperatures and flow rates. This telemetry system enhances immediate response capability to any potential problems. The pipeline is also designed to accommodate an instrumented internal inspection device to detect and record the type and location of corrosion or other defects for long-term monitoring of the pipeline integrity.

31. Nelson stated that while this project does not involve the beneficial use of waste energy from an energy conversion facility, the carbon dioxide being transported in the pipeline facility is a gasification process off-gas stream that is put to beneficial use for tertiary oil recovery. It was previously used as a high volume, low-Btu fuel at the synfuels plant and subsequently vented to the atmosphere. Currently, the synfuels plant emits approximately one-half of the carbon dioxide it emitted prior to this project.

32. To the extent practicable, all effects of pipeline reconstruction will be mitigated. All lands disturbed will be returned to their current land uses. No permanent direct or indirect adverse effects are anticipated.

33. No other corridors or routes will meet the proposed project needs.

34. No irreversible or irretrievable commitments of natural resources are anticipated. All areas of natural vegetation within the ROW will be reclaimed with agency-recommended seed mixtures, lake water quality issues will be mitigated with controls and no agricultural lands will be taken permanently out of production.

35. Several direct and indirect economic impacts will result from the proposed project. The project will provide an economic benefit to DGC and the Great Plains Synfuels Plant, a significant source of employment and income for North Dakota residents, and will stimulate the local economy through the spending of workers' wages and DGC purchases of goods and services. The temporary influx of workers during the construction period will affect markets for temporary accommodations in the area and increase local business activity.

36. DGC is not aware of any other planned developments near the proposed corridor and route.
37. The location and selection criteria utilized were to essentially relocate the replacement line as close to the existing line as possible consistent with safety considerations during the construction process.
38. Nelson testified that with the exception of Lake Sakakawea itself, the route alignment within the corridor will avoid both exclusion and avoidance areas.
39. The proposed facility would not cross any agricultural production or affect the agricultural quality of the cropland, come within 1,000 feet of family farms, ranches or rural residences or any land suitable to irrigation.
40. Berms will be constructed on slopes to control runoff and minimize erosion. Staging areas will be located a minimum of 50 feet from the shoreline with hazardous storage sites and equipment refueling sites at least 100 feet from shoreline, thereby minimizing the potential for impacts to surface drainage flow.
41. The proposed facility will not affect any noise-sensitive land uses, have no visual effect on adjacent areas, no impact on any extractive or storage resources and no impact on any wetlands, woodlands or wooded areas; however, a few trees will be removed at the high water mark of the lake in the temporary lay-down area. Nelson testified that DGC is willing to replace any trees destroyed in the construction process on a two-for-one replacement basis as required by Commission policy.
42. The proposed facility would have no impact on communication facilities.
43. All pipeline construction will be in strict conformance with U.S. Department of Transportation Pipeline Safety Regulations (CFR Title 49 Part 195). A telemetry system and internal inspection device is used to monitor the integrity of the pipeline and enhance response time to the pipeline in the event of an emergency. Water used for hydrostatic testing of the new pipeline will be chemical free and will be properly disposed of after testing has been completed.
44. In the unlikely event of an accidental release from the pipeline, carbon dioxide and small amounts of other minor constituents including H₂S would be released into the atmosphere. In the event of a pipeline rupture, block valves are used to isolate the affected section of pipe and thus limit the amount of product released. Leaks are more difficult to detect and product could potentially be released over a longer period without detection.
45. In order to predict the possible human health consequences that could potentially result from pipeline ruptures or leaks, DGC conducted a worse case modeling exercise to determine the extent of the area near the pipeline that might be affected by ruptures

or leaks. The modeling results indicate that a catastrophic failure resulting in a hole as large as the pipeline itself presents the worst-case scenario in terms of highest concentrations of carbon dioxide or H₂S at the greatest distances. A full pipe diameter rupture could potentially produce concentrations of carbon dioxide considered immediately dangerous to life and health (IDLH) at a distance of 760 feet. Assuming that H₂S is approximately 0.89 mol percent of the pipeline product, a full diameter failure of the pipeline could potentially cause H₂S concentrations to be considered an IDLH at a distance of 1,940 feet from the rupture.

46. A statistical analysis was performed to assess the risks to an individual from accidental release of carbon dioxide and H₂S at certain locations or receptors identified along the pipeline route. Carbon dioxide and H₂S total impact probabilities at receptors were estimated using data on the likelihood that an accident will occur anywhere along the pipeline, meteorological conditions, and the chance that an accident will be located within the predicted maximum threshold impact distance from a receptor. Only the H₂S 30-minute IDLH concentration of 100 ppm was predicted to reach a receptor, and the predicted probability of impact was one in 44,000. The probability of impact for the other thresholds did not exist since the threshold concentrations were not predicted to be observed at any receptors.

The total impact probabilities determined in this report only assess the probability of an impact at the receptor indicated. Variables such as the population density and frequency of visits at these receptors have not been included in these calculations since the distribution of these variables is unknown. Implicit in the impact probabilities is a population of 1.0 person-years (e.g. one person at the receptor for every minute during the year). Therefore, the actual carbon dioxide and H₂S exposure risks may be overstated for remote areas where population densities are low and receptor occupancy is not full-time. Conversely, the risks may be understated for receptors with high population densities and/or relatively long residence periods.

47. DGC has developed an Emergency Response Plan. This Plan addresses an accidental release of the operating pipeline and outlines pre-emergency planning and education, operational safety precautions, emergency response procedures and associated agency coordination. DGC has distributed information regarding emergency preparedness and response to appropriate local agencies and the public residing adjacent to the proposed facility.

48. Impacts to animal health and safety will be minimized through sound construction and operation practices. Surface water, typically utilized by animals, will be protected from contamination by locating staging areas a minimum of 50 feet from stream banks and hazardous substance storage areas and refueling sites a minimum of 100 feet from stream banks.

49. Impacts to plant life would be limited to the disturbed portions of the ROW.

50. Nelson stated DGC has a longstanding commitment to North Dakota's people and economy, providing continuous employment for managerial, technical and operating staff. DGC employs a substantial number of North Dakota natives. For this project, DGC is utilizing North Dakota staff for project management and technical support. DGC will solicit bids from North Dakota-based companies for equipment and services whenever possible.
51. DGC has attempted to minimize the cost by installing the new line as close to the existing line as possible and reducing the downtime for the carbon dioxide pipeline when the tie-ins are made.
52. No citizen coordinating committees were consulted, as DGC believes none are appropriate for this type of pipeline project.
53. While DGC's present customers are located in Saskatchewan, the pipeline is installed with fittings (mainline valves) which would allow for the construction of lateral pipelines to serve potential future customers in North Dakota.
54. Installation of the pipeline will be performed by companies contracted for the project. DGC requires that these companies comply with all appropriate federal, state and local laws.
55. During construction, DGC will provide silt control/monitoring in the lake and after construction, it will monitor revegetation.
56. The proposed pipeline parallels the existing pipeline and ROW.
57. The proposed facility does not involve any other existing or proposed transmission facilities.
58. The primary design and construction limitations considered are to provide a minimum of six feet cover over the new pipeline and to minimize impact to the lake and the adjacent shore land.
59. Nelson testified that DGC is committed to constructing the proposed pipeline as economically as possible while strictly adhering to the Commission's criteria. The anticipated construction cost for installation of the proposed facility is \$10.5 million.
60. Surveys for the interior least tern and piping plover are conducted annually by the COE. Based on discussions with the COE and USFWS, no nests have been recorded near the proposed route. If agency surveys indicate that active nests are present within 0.25 miles of the route, potential mitigation measures will be evaluated in coordination with the COE and USFWS.
61. The staging area ROW will be cleared of obstructions and graded where necessary to permit construction equipment to operate safely. The extent of clearing

and surface preparation will be restricted to the ROW and to the minimum area necessary for construction. DGC will adhere to landowner easement provisions.

62. Shrubs will be removed from the ROW. The root systems of woody plants on the spoil side of the ROW will be preserved where possible. Where shrubs are large enough to interfere with construction equipment, additional clearing may be necessary. Cleared vegetative material may be chipped and spread over disturbed areas to serve as mulch, burned where permitted, placed in piles for wildlife habitat or removed to disposal areas as specified by agencies with jurisdiction.

63. Trees will be cut and removed from the ROW, staging or work areas and salvaged or disposed of according to landowner or agency requirements. Trees will be felled parallel to and within the construction ROW.

64. In some areas, cutting and filling may be necessary to permit safe construction activities. Cuts and fills will be limited to that necessary for trenching operations. Topsoil will be preserved to the extent practical. Subsoil materials from cuts will be stockpiled for recontouring upon completion of trenching operations. Excess material will be shaped to blend with adjoining lands and to provide a landform suitable for revegetation.

65. Trenching on land will be completed with a backhoe. Where standard ditching is performed, the ditch spoil will be placed in one windrow. Where double ditching is required, the topsoil will be excavated and placed in a windrow separate from the ditch subsoil. Mixing of topsoil with subsoil will be prevented by stripping topsoil either from the full work area or from the trench and subsoil storage area (ditch plus spoil side method).

66. All land trench areas will be restored to original contours.

67. After the pipe has been lowered into the trench and its position inspected and approved, the trench will be backfilled. With standard backfilling, the windrow of spoil material will be returned to the trench with a crown of soil, normally 12 inches, which compensates for settlement. Excess spoil will be spread in a thin layer over the ROW.

68. Where topsoil is segregated, the windrow of subsurface soil will be returned to the trench leaving sufficient space for the return of the topsoil windrow.

69. Access to the ROW will normally be from existing public roads. Where public roads do not provide sufficient access to the ROW, temporary access roads may be required. No new permanent access roads will be required. The contractor will be responsible for obtaining permission for utilizing private roads and trails. Upgrading existing trails or constructing new temporary access roads, if required, will be in accordance with the following guidelines: Temporary roads will be located where possible to avoid erosion-prone areas, drainages, areas of woody cover, wetlands or other sensitive areas and are subject to approval by DGC and the landowner, or

appropriate agency. Temporary roads will be designed with culverts properly located to minimize erosion and sedimentation dust will be controlled, where required, by a suitable water sprinkling program or surfacing with dust-free materials.

70. The "controlled depth tow" method of construction will be used where pipe sections are welded on-shore and pulled into place. Heavy equipment to be used in the excavation activities for the lake crossing will consist of barge-mounted dragline, towboat, anchor/fuel barge and a hydrographic survey boat. Other equipment will consist of that needed to transport, offload, position and handle pipe, including welding machines, bulldozers, track hoes, motor graders and miscellaneous service vehicles. Fuel will be provided in support vehicles designed for safety and for pollution control. Fuel reserves, other than that contained in the service vehicles, will not be stored on-site.

71. Bank erosion control measures will be implemented at both shorelines to prevent exposure of the pipes to damage and to prevent loss of material shoreline. The control measures will be implemented in the shoreline interval beginning at the water level at the time of construction and continuing to existing riprap. As required by the U.S. Department of Transportation, Office of Pipeline Safety and in keeping with good industry practices, DGC will maintain the lake banks at the pipe crossing and augment the erosion control measures if erosion occurs.

72. Temporary erosion and sedimentation controls will be installed immediately after initial disturbance of the soil. They will be properly maintained on a daily basis throughout construction and reinstalled as necessary until replaced by permanent erosion controls or restoration is complete. Where appropriate, slope breakers will be installed to reduce runoff velocity and divert water off the construction ROW. These will be constructed of soil, silt fence, staked hay or straw bales, or sandbags depending on site conditions. The type and spacing will be determined based on slope, soil erodability, ground cover, expected runoff and capacity requirements. Sediment barriers will be used to stop or reduce the flow of sediment. These will be constructed of materials such as silt fence, staked hay or straw bales or sandbags. Water body sediment barriers will be installed immediately after initial disturbance of the water body or adjacent upland. These will be installed along the edge of the construction ROW as necessary to contain spoil and sediment within the ROW. These sediment barriers will be removed during ROW cleanup. Mulch will be applied to stabilize the soil surface; it will consist of straw, hay, erosion control fabric or some functional equivalent. Mulch will be applied before seeding if restoration activity is interrupted for extended periods, such as when seeding cannot be completed due to seeding period restrictions.

From the foregoing Findings of Fact, the Commission now makes its:

Conclusions of Law

1. The Commission has jurisdiction over the applicant, DGC, and over the subject matter of this application under North Dakota Century Code Chapter 49-22.
2. The pipeline proposed by DGC is a transmission facility as defined in North Dakota Century Code Section 49-22-03.
3. DGC's proposed pipeline is of such length, location and purpose that it will minimize adverse effects upon the environment, and upon the welfare of the citizens of North Dakota, while ensuring continuing system reliability, integrity and efficient use of natural resources.
4. DGC's proposed route is compatible with the environmental preservation and efficient use of resources.
5. It is appropriate for the Commission to issue DGC a Corridor Certificate and Route Permit.

From the foregoing Findings of Fact and Conclusion of Law, the Commission issues its:

Order

The Commission orders:

1. DGC's application for a waiver of procedures and time schedules is granted.
2. Certificate of Corridor Compatibility Certificate Number 97 designating a transmission facility corridor is issued to DGC.
3. Route Permit Certificate Number 107 designating a transmission facility route is issued to DGC.
4. A preconstruction conference shall be held prior to commencement of any construction, and shall include a DGC representative, the construction supervisor, and Commission staff to ensure that DGC fully understands the conditions set forth in this order.
5. DGC shall comply with the rules and regulations of all other agencies having jurisdiction over any phase of the proposed pipeline, and shall obtain all other necessary licenses and permits, and shall provide copies of all licenses and permits to the Commission prior to construction of the pipeline.

6. DGC shall inform the Commission of its intent to start construction on the pipeline prior to the commencement of construction, and once construction has started, DGC shall keep the Commission updated of construction activities on a weekly basis.
7. The pipeline shall be buried to a minimum depth from the ground surface to the top of the pipe of 72 inches across the lakebed.
8. DGC shall construct and operate the pipeline in the manner described in its Application and at the hearing, and in accordance with all applicable safety requirements.
9. DGC shall promptly report to the Commission the presence in the permit area of any critical habitat of threatened or endangered species, or of bald or golden eagles that DGC becomes aware of and which were not previously reported to the Commission.
10. All cultural resource mitigation plans must be submitted to the North Dakota State Historical Preservation Officer for approval prior to the start of any fieldwork and construction activity. If any cultural resource, paleontological, archeological, historical, or gravesite is discovered during construction, it shall be marked, preserved and protected from further disturbances until a professional examination can be made by the State Historical Society, a report of such examination is filed with the Commission, and clearance to proceed is given by the Commission.
11. All crossings of graded roads shall be bored unless the responsible governing agency specifically permits DGC to open cut the road. All pre-existing roads and lanes used during construction shall be restored to a condition that will accommodate their previous use, and areas used as temporary roads during construction shall be restored to their original condition.
12. Construction shall be suspended when weather conditions are such that construction activities will cause irreparable damage, unless adequate protection measures approved by the Commission are taken.
13. To the extent available, at least 12 inches of topsoil over and along trench areas where cuts must be made shall be stripped and segregated from the subsoil and be replaced only after the subsoil is replaced.
14. Reclamation along the right-of-way shall be continuous and coordinated with the construction.
15. Reclamation, fertilization and reseeding are to be conducted by DGC according to the National Resources Conservation Service recommendations, unless otherwise specified by the landowner and approved by the Commission.

16. DGC's obligation for reclamation and maintenance of the ROW shall continue throughout the life of the pipeline.

17. The width of any clear cuts through any wooded areas and shelterbelts shall be kept at a maximum of 50 feet, to the extent possible.

18. DGC shall plant replacement trees and shrubs on a two-to-one basis for each tree or shrub destroyed in the construction process. The Commission will monitor the survival rate of replacement tree and shrub plantings for a period of three years after planting, and may order additional plantings if survival rates are less than 75%. DGC will be required to provide information to the Commission as to the location of tree planting sites and the number of plantings at each site.

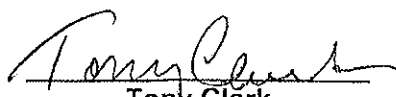
19. DGC shall provide the Commission with a copy of the design specifications for the construction of the pipeline showing the location of the pipeline as built.

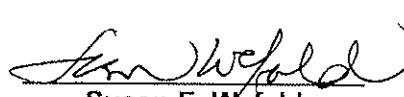
20. Aquatic nuisance species (ANS) are a major concern of the North Dakota Game and Fish Department (the Department). The contractor, including any and all subcontractors or other involved in this project, are required to take appropriate and reasonable precautions to prevent the introduction of ANS to the state's waters or the movement of ANS within North Dakota or between North Dakota waters. These ANS precautions extend to any and all vehicles, vessels, trailers, pumps and such equipment that will be used in the waters of the state. The contractor will provide the Department a reasonable opportunity to inspect all vehicles, vessels, pumps, and equipment that will be used in the waters of the state prior to those items being launched or placed in the waters of the state.

21. The authorization granted by the route permit is subject to modification by order of the Commission if deemed necessary to further protect the public or the environment.

22. After the corridor and route certificates have been issued and all costs of hearings, publication, and any other related expense have been paid from the application fee, the Commission shall refund all but \$5,000.00 of the remaining application fee. If the balance of the application fee at the time is less than \$5,000.00, the Commission shall retain the entire amount. When construction and reclamation are complete and when the Commission has concluded that DGC's tree mitigation project is satisfactory, the remaining balance of the application fee shall be refunded.

PUBLIC SERVICE COMMISSION


Tony Clark
Commissioner


Susan E. Wefald
President


Kevin Cramer
Commissioner

**PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA
Certificate of Corridor Compatability**

Certificate Number 97

This is to certify that the Commission has designated a transmission facility corridor for Dakota Gasification Company, which is described as follows:

In McKenzie and Williams Counties, North Dakota a corridor located in Township 154 North, Range 95 West, Sections 15, 16, 21, 22, 27, 28, 33, and 34

This certificate is issued in accordance with the Order of this Commission dated June 27, 2007 in Case No. PU-07-184 and is subject to the conditions and limitations noted in the Order.

Bismarck, North Dakota, June 27, 2007.

ATTEST:

PUBLIC SERVICE COMMISSION


Executive Director


Commissioner

**PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA
Route Permit**

Certificate Number 107

This is to certify that the Commission has designated a transmission facility route for Dakota Gasification Company, which is described as:

In McKenzie and Williams Counties, North Dakota, a CO2 pipeline approximately 11,400 feet in length located in Township 154 North, Range 95 West, SE ¼ Section 16, NE ¼ and SE ¼ Section 21, NW ¼ and SW ¼ Section 22, NW ¼ and SW ¼ Section 27, and NW ¼ and SW ¼ Section 34

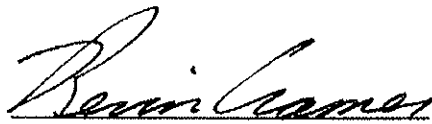
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Bismarck, North Dakota, June 27, 2007.

ATTEST:

PUBLIC SERVICE COMMISSION


Executive Director


Commissioner

Agricultural ECONOMICS

Legal Affairs

Negotiating Oil and Gas Leases on Indiana Farmland¹

Gerald A. Harrison
Agricultural Economics

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Introduction

Besides the discovery of new accumulations, changes in the price of oil and gas, and advances in technology and deregulation are forces that encourage widespread leasing activity in southern Indiana. Landowners in several Indiana counties continue to have an opportunity to lease or convey the rights to oil and gas exploration and production. Granting of rights to test-drill and to produce oil and gas is an important transfer of property rights.

One might say that the oil and gas producer/lessee becomes a "partner" in business. Landowners should control this relationship through the lease. Landowners should also become fully informed about the rights and duties of oil and gas exploration and producing companies. These rights and desired limitations and the landowners' payments for delays and property damages, and for the actual oil and gas produced should be clearly stated in the lease. Lawyers experienced in

Disclaimer: This paper is intended for educational purposes only. Individuals with legal interests at stake should consult an attorney who is informed on these matters.

¹ This publication was revised by a co-author of the 1982 version, Gerald A. Harrison, Extension Economist, Agricultural Economics Department, Purdue University. Owen Mohler, deceased, was lead author of the 1982 draft. Mohler was legal consultant to the Indiana Farm Bureau. John A. Rupp, Head, Energy Resources Section, Geological Survey in Bloomington and a staff reviewer, Division of Oil and Gas, Indiana Dept. of Natural Resources provided numerous suggestions for this revision. Others who supplied useful suggestions or were reviewers include: Ray Ballard, Extension Educator, Floyd County; Jay Ritter, Gallagher Drilling, Inc., Evansville, IN; Marian Percy, Attorney, Corydon, IN; David Frette, CPA, Washington, IN and Tom Tucker, CPA, New Albany, IN. A special thanks for professional editing by Laura Hoelscher. Gerald Harrison's address is: Agricultural Economics Department, 1145 Krannert, Purdue University, West Lafayette, IN 47907-1145. Phone: 765-494-4216; Fax: 765-494-9176; E-mail: < harrison@agecon.purdue.edu >.

dealing with both the landowner and lessee relationship and the production of oil and gas may offer many lease drafting suggestions that may benefit a landowner.

Talk to other landowners (lessors) and learn more about their experiences with exploration and production and the royalties they received. Seek legal counsel experienced in these matters before signing an oil and gas lease. A standard form lease offered by a landman may not offer all that can be negotiated by a lawyer experienced in protecting the landowner interests.

A lawyer can clarify your rights, responsibilities, and risks under a gas and oil lease. For example, the landowner should be concerned about the potential for his or her liability for oil and other types of pollution under federal and state law. Individual landowners with small parcels may join together with neighbors in order to pool resources for hiring lawyer with oil and gas lease and production experience.

The property owner must recognize that the lessee and future owners of the leasing rights have a long-term interest in the property similar to a utility with a right-of-way for an electric power line.

Oil and gas leases are defined for a limited period similar to farmland leases. However, if production is initiated and continues at some acceptable commercial rate, the period of the lease is indefinite. In fact, options under the typical lease can extend the period of the lease when there is little or no production.

In order to have a say about the timing and location of exploration and production activity, well sites, pipeline placement (including laying technique and depth), and roads (including specifics for damages to farmland, crops, and improvements), one should have lease provisions to cover these matters.

However, signing an oil and gas lease with the desired provisions may not be an easy decision. For example, individuals may be concerned about the possibility that production may begin on a neighbor's property that draws from your property.

If land is not under a pooling agreement through an oil and gas lease, the owner of the land will not receive a share of the royalty. In a "wildcat" area (where oil and gas reserves have not been proven),

experts suggest that if production begins near your property, there will be a chance for leasing on the "second wave" of activity. With a second wave of activity, lease terms may improve compared with an initial leasing opportunity. The amount of signing bonus, delay rental, royalty, other benefits, and damage provisions provided in the lease may be sufficient to convince a landowner to sign a lease rather than to wait for a better deal. Current and alternative uses for the land to be covered by the lease may be a deciding factor.

Considerations Before Signing

Chances of Discovering Oil or Gas

If the landowner has a good estimate of commercially available oil or gas underlying his or her land and the cost of its production, a more informed leasing decision can be made. With present technology, a test drill site is necessary to detect the presence or absence of available oil or gas. However, existing geological information can show the possibilities of oil and gas discovery. Records and maps exist by counties of prior drill sites and information on current and historical production. Geological consultants or petroleum engineers may review records and maps to develop an understanding of production possibilities and the potential for profitable production.

Maps and publications may be obtained from: **Indiana Geological Survey, 611 North Walnut Grove, Indiana University, Bloomington, IN 47405. Phone: 812-855-7636; Bulletin 42-N, Petroleum Industry in Indiana (1995) is available for \$4.00. Also Bulletin 42-I, Coal Resources of Indiana (1973) is available for \$1.50. Postage and sales tax are extra. Additional detailed information is available from individual test well records. Information is available from John A. Rupp, Head, Energy Resources Section, Indiana Geological Survey, phone: 812-855-1323.**

Protection of Farmland and Improvements

When oil and gas are discovered and produced, cropping can continue, and landowners and tenants will benefit from minimum damage to the soil and farmland improvements. Farmers should learn the physical needs of exploration and production, such

as equipment used, nature of well sites, roads, pipelines, and storage tanks. Farmers and landowners may wish to learn about existing Indiana rules and regulations that govern well drilling, production, and restoration activity. Information on Indiana rules and regulations is available from: **Division of Oil and Gas, Indiana Department of Natural Resources, 402 West Washington St., Rm. W-293, Indianapolis, Indiana 46204. Phone: 317-232-4055.**

Investigation of the Leasing Company

In Indiana, companies can engage in oil and gas leasing without a license, bond, or investigation or approval by any Indiana agency. Landowners may want to seek information on the leasing company's reputation and performance. The initial lessee may be a middleman (landman or broker) intending to sell leases to a drilling company. Ask the company agent for information such as several lessor and producer references and other company information that might be investigated. Farmers can save time and cost by pooling their efforts in conducting such an investigation—perhaps with the assistance of an attorney. A farmers' organization might be helpful in this regard.

Oil and gas leases are usually pre-printed forms which are likely to include terms favorable to the lessee. The lessee would prefer to use a standard-form contract to avoid drafting costs. Further, if leases are not similar, there may be difficulty in evaluating leases for subsequent sale or assignment to a drilling company. However, the lessor should know that any lease form can be modified, perhaps with provisions important to the lessor.

Evaluating Your Neighbors' Decisions

Landowners often follow the lead of neighbors on many important matters. Depending upon the nature of the lease and other facts, this may not be wise in the matter of signing a gas and oil lease. While it is possible that a neighbor's well could draw from a reserve that underlies your property, if there is a nearby "strike," the landowners with unleased land will probably obtain a more favorable oil and gas lease than those who sign early or do not bargain for detailed damage clauses or superior bonuses, delay rents, and royalties. A customary royalty is one-eighth (1/8) of the "value of the production."

It would be wise for the landowner to get an explanation of how the value of production is determined, for example, in the case of natural gas production, what costs may be subtracted before the rate of the royalty is applied. In the case of natural gas, the value of the proceeds may be taken at a point remote from the land to which the lease is applicable. In short, processing and transportation or pipeline costs may be subtracted in arriving at the "value of production."

However, do not overlook the time value of money. Money at an early date may be equivalent to or more than a larger sum at a later date. But an outlook of rising oil and gas prices and higher royalties could convince a landowner that a delay could result in a larger sum in the future.

On the other hand, if a single lessee is unable to obtain a large enough area committed to leases, the lessee may not lease any land in a given area. If too few acres are under lease, the lessee may be unwilling to bear the overhead costs of exploration and test drilling. In effect, they may let the leases obtained go into default under the implied covenants of the lessee to explore and produce. This situation is likely to prevail in a "wildcat" area, which may be the appropriate label for much of Indiana.

Seeking Legal Counsel

In some areas of Indiana, oil and gas leasing activity existed during an earlier period when leases were granted for an indefinite period. Therefore, a landowner may need to check to see if his or her property is not already under an oil and gas or mineral lease. It is possible that a lease already exists that has not been recorded. A lawyer can assist in clearing up any doubt about prior oil and gas leases. However, the leasing company may take steps to check the landowner's title once a lease is signed. Provisions exist in Indiana law to help clear a landowner's title of dormant mineral leases.

In evaluating the legal aspects of oil and gas leases, experienced legal counsel may be helpful in drafting and negotiating specific provisions. Many of the ideas shared in this publication were obtained from the writings of lawyers and other professionals experienced in gas and oil leases and especially with the problems that may arise once the lease is in place and production begins. This publication does not

discuss all the concerns that a property owner may have and that a lawyer could help alleviate by drafting provisions into an oil and gas lease for a particular situation. Legal counsel may be helpful after drilling and production operations begin, but covering the major issues in the lease is the best way to handle problems that may arise.

Tax and Estate Planning Considerations

Rental (delay or “shut-in”) payments, bonuses, and royalties from gas and oil production are included as ordinary income for federal income tax purposes. However, net royalty income from oil and gas production is reduced for federal income tax purposes by the *greater of a cost basis deduction or a percentage depletion allowance*. Unless a landowner allots some of the purchase price of his land to oil and gas deposits, there is no cost basis assigned to oil and gas that may be produced. For the lessor, the **percentage depletion allowance** is limited to 65 percent of **taxable income** for the year. The **depletion allowance** for oil and gas is 15 percent. The depletion allowance cannot exceed 100% of the **actual taxable income from the property before the depletion deduction**.

For example, a lessor/landowner has \$10,000 of royalties, taxable income from the oil and gas property of \$9,000 and total taxable income of \$30,000. The **tentative depletion allowance** is \$1,500 (15% of \$10,000). The **taxable income limitation** is \$9,000 (100% x \$9,000) and the **overall taxable income limitation** would be \$19,500 (65% x \$30,000). Neither **limitation** is a factor in this example, so the **depletion deduction** would be \$1,500. In this example, there was no cost basis for newly discovered oil and gas, so the cost basis deduction is zero. Thus the depletion allowance, as calculated, would be the applicable deduction—\$1,500 in this example.

Indiana law provides for a severance tax on the value for all oil and gas. The tax is levied at the greater of one percent or \$0.24 per barrel of oil and one percent or \$0.03 per thousand cubic feet of gas.

Also, Indiana law includes a special procedure for assessing oil and gas for real property tax purposes. Landowners should find out how an oil and gas lease may affect their property taxes. Increases in real

estate tax due to gas and oil production may be an item the landowner will want to assign to the lessee.

Both income tax and estate planning may suggest shifting the income rights (if not full ownership rights) of oil and gas deposits to lower income family members. Further, special valuation of farmland for federal estate tax purposes does not apply to mineral rights.

Also, if the land is being acquired under an installment contract, it is likely that neither buyer nor seller independently has the right to sign a binding lease. Mortgages may include a provision that limits the landowner/mortgagor’s leasing rights.

Landowners must be cognizant of the fact that once a gas and oil lease is signed, the lessee’s mineral rights take on an independent nature. The lease will be recorded at the courthouse in the county where the land is located, establishing an ownership interest in the landowner’s chain of title.

Provisions That May Be Negotiable

Mineral Rights and Other Rights Granted

It may be in the best interest of the landowner to be sure that the oil and gas lease is limited in its granting clause to oil and gas and associated hydrocarbons. The lessee’s standard lease form may include a grant of “other minerals.” Royalties and lease provisions for oil and gas exploration and production may be inappropriate for certain other minerals. It is advisable to negotiate each mineral separately. Likewise, underground storage rights for natural gas should be separately negotiated.

Lessees may also attempt to cover the storage of gas in wells or underground formations. Proper compensation should be provided for storage if this is to be permitted. The landowner may demand a separate payment for lessee pipelines running across his or her property—\$10 a rod may be attainable.

Duration of the Lease

Oil and gas leases are drafted with a stated **primary period** (before production begins). As long as **delay rental payments** are offered or made as promised, drilling or production might not have to

begin before the primary period ends for the lease to remain valid.

The lessee may suggest a long primary period, perhaps 5 to 10 years, which the landowner may feel is excessive for exploration or speculation. One to 2 years may be a more favorable primary period. Landowners who are offered a nominal delay rental of \$1 per acre might favor waiting for a better offer. It is important to recognize that the requirement to have proceeded with drilling is satisfied by drilling on land included in a pool arrangement. The lessee need not have drilled or be producing in paying quantities on a specific parcel to keep that parcel owner bound by a lease. **Dry hole provisions** in a lease may require no delay rentals in the primary term once test drilling begins or during specified lapses between dry holes. Landowners can insist upon a clause which stipulates that the test well(s) must be drilled within a short period of time.

Typically, the **secondary term** (starts with beginning of production) may continue indefinitely while there is production of oil, gas, liquid hydrocarbons, or constituent products in paying quantities. Landowners may seek a lease without a secondary term or other delays rather than a long term lease.

Damage to Crops, Farmland, and Improvements

While oil and gas leases commonly provide payment for damages, it is also true that the lessee has considerable freedom to go on the leased land to explore or drill and produce. Further, Indiana has rules and regulations for well drilling, dry holes, and producing wells. Indiana rules require a \$2,000 bond per test hole or well site. Alternatively, there may be a blanket bond of \$30,000 for all wells drilled by the person for the duration of the bond. Indiana regulations require the drilling company to restore the surface as nearly as practicable to the condition it was prior to the drilling of the well after completion and/or plugging.

The bond is subject to forfeiture should an operator of the well fail in adhering to Indiana oil and gas laws. Funds from forfeited bonds are used to clean up sites on an environmental priority basis. It does not cover damages to fences, tile, crops, roads, soil, and buildings away from the dry hole or well site or to livestock. Additions to the Indiana rules should be

in the lease. Following is a list of specific provisions a landowner may consider.

a. Reserve the right to approve the location of drill sites, tanks, access roads, and pipelines. You may desire that a drill site to be a minimum distance from buildings and property lines. The reservation of location of a drill site is important to the landowner in order to maintain the value of his or her property. In fact, the landowner may be wise to limit the lessee to one drill site at a time—with consideration of the operator's performance from a preceding location.

b. Require all pipelines to be buried using the "double ditch" method and below tillage depth, or at a specified depth, such as 36 inches—safely below all possible tillage depths.²

c. Require the drilling company to be accountable to the landowner for damages "to the surface of such lands or improvements or growing crops located thereon," unless the lease provides otherwise. The lease should be specific in making the company liable for "all damages to growing crops, trees, fences, buildings, tile lines, drainage ditches, springs, water wells, any other improvements, livestock, and to the surface of the lessor's property." The Indiana law makes the driller liable to the state of Indiana for various damages, but not necessarily to the landowner.

d. Require fences around all drilling equipment to help protect livestock or children and to prevent vandalism.

e. Require the company to indemnify and hold the landowner harmless from all claims, demands, and legal problems and law suits stemming from activities undertaken by the company or its assignees.

f. Require the lessee or drilling company to carry liability insurance as added security from claims by neighbors government entities and others. Examples of problems that may arise include environmental law violations and interference with agricultural drainage systems.

² The "double-ditch" method refers to the practice of separating the top soil and subsoil back and replacing it into a trench in the same profile that naturally occurs. The top soil will be placed on the surface above the subsoil when the trench is filled.

Bonuses, Rents, and Royalties

A **bonus** (a one-time payment) is the term for the money provided to the lessor in return for the landowner's signature on the lease. It may be the initial year's rent and comparable to the **delay rental** mentioned above, or it may be some amount in addition to a first year's rent. If the modern practice followed the historical practice of only a few weeks or months delay before drilling, the bonus might be the only payment before royalties begin if there is a "discovery" or before there is abandonment and termination of the lease.

Modern practice and negotiations anticipate a delay of a few years before drilling and production or termination. Thus, the bonus and delay rentals may be more significant than in the past, because the landowner may have to lease for a primary term of 3 to 10 years or not at all.

Most landowners will feel that the nominal offer of \$1 an acre as a bonus or delay rental is not sufficient to commit their potential oil and gas reserves for an historic one-eighth (1/8) royalty and risk damage to their property. Even if the damage is obvious, the landowner risks not being adequately compensated. Past reports from within Indiana and nearby states are of bonuses ranging from \$2 to \$300 per acre and delay rentals of \$1 to \$45 per acre. Logically, the greater the expectation of a discovery, the more likely a landowner may get a large bonus and a commitment for a substantial delay rental as well as other favorable provisions in the lease. Also, the higher the quality of the land for cropping purposes, the higher the bonus and delay rental ought to be.

"Royalty" has its roots in England, where that was the term for the share of production from mines or quarries reserved by the crown. In the 19th century, the amount for the landowner from oil production was set at 1/8th, and that is the standard offer today. Royalties up to 3/16 have been reported, but again, bargaining power for a higher than standard royalty may depend upon the expectation of a substantial discovery. Lessees who discover a large quantity available for production are in a better position to share a larger than usual percentage.

Rather than engage in lengthy "haggling," a landowner might agree to a bonus, rental payment, and royalty that appears to be the lessee's limit, but

only after obtaining a provision in the lease that requires the lessee to provide the same higher bonus, rent, or royalty that any other landowner might receive in a defined area. Landowners may want to require royalty payments on a monthly basis.

Access to Books and Records of the Drilling Company

The landowner should require a reasonable access mechanism to the books and records of the drilling or producing company so that he or she can evaluate the adequacy of the royalties received and obtain further information. This is another area where landowners might benefit from a cooperative effort to provide for an expert to examine books and records on their behalf, because many landowners may not feel competent to audit lessee information. However, the landowner may find that "division orders" from crude buyers and other industry reports may provide satisfactory proof of the volume or quantity of production from his or her land.

Rights to Free Gas and Water

Leases typically contain provisions for free use by the lessor of gas and water found on the premises. The landowner should require that any water use by the company cannot restrict the supply of water for domestic, livestock, or agricultural purpose, and that the company shall not take water from wells, tanks, ponds, or reservoirs of the landowner. Likewise, the landowner may want to consider provisions limiting free use of gas or other hydrocarbons. However, the landowner or a farm tenant may be able to benefit substantially from the use of a supply of gas. However, because of safety issues, lessees may be unwilling to grant a right to a gas supply for a property owner directly from the production on a given parcel of land.

Lessees will likely limit the lessor's free amount to that sufficient for a residence and will not pay for the pipeline from the well to the residence. A farmer may want to negotiate for the right to additional gas for livestock facilities and grain dryers at an economically advantageous rate.

Pooling Provisions

Most leases allow the drilling company to pool or form a drilling unit with lessor's land in combination with the property owned by adjoining landowners.

Thus, when oil or gas is produced from any part of a drilling unit, all owners share in the proceeds in proportion to the amount of property they own in the unit.

As indicated above, pooling provisions may also limit the need to pay a delay rental to all members of a pool when drilling is underway on one parcel in a pool, yet keep all parcels bound under their respective leases at least throughout a primary period. Indiana regulations provide 10-acre drilling units for sandstone reservoirs, 20-acre drilling units for all other reservoirs, and a minimum of 40-acre drilling units for commercial production of natural gas from a reservoir deeper than 1,000 feet. Petitions to modify spacing can be filed with the Division of Oil and Gas.

Exercise caution in granting a company the unrestricted right to pool the leased premises, and in any event, be sure that you understand completely the effect of a pooling provision.

If necessary, submit to pooling in the lease only to the extent necessary to meet the requirements of Indiana law. In all cases, try to negotiate the inclusion of a "Pugh" clause in the lease that provides for the severance of the lease into separate tracts whenever less than all of the premises is included in a single pool or drilling unit.

Consent to Assignment of a Lease

Require that the landowner consent to any assignment of the lease or at least that he or she receive written notification of such assignment. The landowner may also wish to reserve a right to consent to the change of an operator.

Warranty Clause

To avoid possible litigation expenses, landowners should seek to delete reference in the lease that infers they will warrant or defend title to the land. The initial lessee is likely to complete some type of title check and prevent payment of any bonus until he or she is satisfied of a lessor's rights in the mineral interest for a specific parcel. But the lessee may miss or ignore a problem. The lessor under a warranty clause could be forced to defend title at a later date.

Termination of the Lease

If the lessee fails to comply with the stipulations in the lease such as payment of a delay rental, a landowner, with the help of legal counsel and a court proceedings, if necessary, may demand a termination of the lease because of breach. The lessee or his or her assignee may simply "give up" and let the lease "automatically" terminate by the provisions of the lease. It may be useful to have a provision in the lease which requires the lessee to record a release from the lease when it is clear that the landowner is entitled to a termination.

Failure of Implied Covenant to Drill

The law provides implied covenants or promises on the part of the lessee. First, there is an implied covenant to drill test wells within a reasonable time so that the purpose of the lease (production of oil and gas) can be fulfilled. If a landowner convinces a court of a lessee's failure under this covenant, there would be grounds for termination of the lease. This covenant may be more important for lease forms used in past years providing for an extended term without payment of a delay rental. However, this covenant may still apply in Indiana even though the lease permits a delay during the primary period.

Failure of Implied Covenant to Develop

Second, there is an implied covenant to develop the leased premises as long as it might be profitable. This covenant suggests that a lessee must limit the delay following a dry hole if there is reason to believe that another test drill could produce a discovery.

Further, even if there is a substantial discovery, the driller may be compelled to drill additional wells unless he can show that more wells could not be profitable. Of course, lease pooling provisions and Indiana regulations limit the duty of the lessee driller under this covenant.

Seeking Legal Counsel Before Termination

Before attempting to terminate an oil and gas lease, the landowner should consult an attorney as to the proper procedure pursuant to Indiana Code Section 32-5-8-1. If the landowner desires to cancel his lease for failure to drill test wells, he or she must not accept delay rental payments or else the lease may remain in force and not be terminated on grounds of failure to develop. Refusing delay rentals may be most effective when the payments are late.

Taking Possession of a Well

After production operations are complete, drilling companies may offer a “non-paying” but producing well for sale or free of charge to the landowner. When the landowner takes possession of the well, the landowner takes responsibility for plugging the well, which may be expensive; and there may be increased exposure to environmental liabilities. Carefully investigate all the costs and benefits before taking possession of the well.

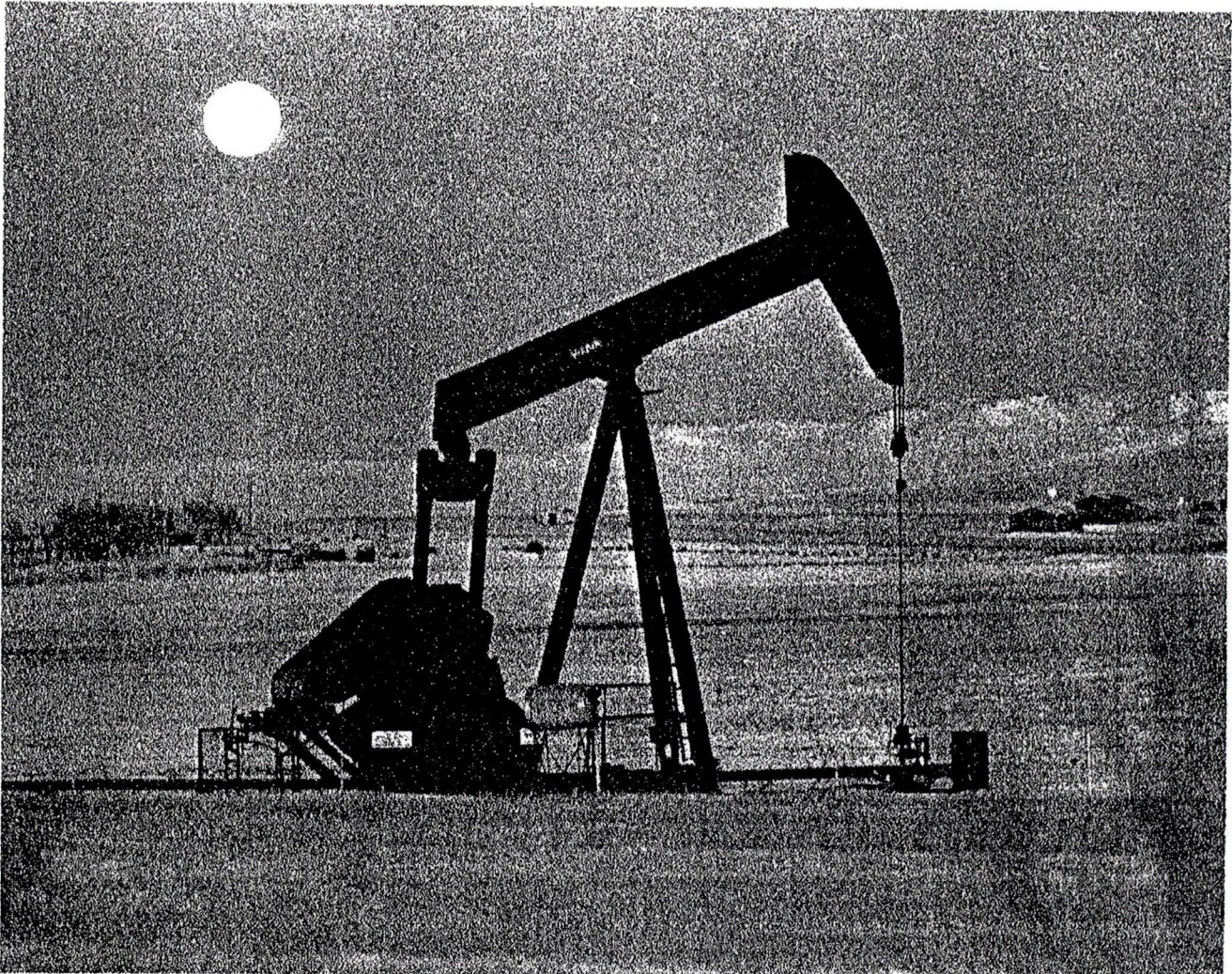


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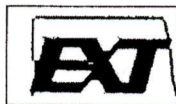
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NORTH DAKOTA OIL & GAS LEASING CONSIDERATIONS

RON ANDERSON
RESOURCE ECONOMIST

COOPERATIVE
EXTENSION
SERVICE



North Dakota State University Fargo, North Dakota 58105

12 AECO-2

Exhibit C

ACKNOWLEDGEMENTS

A recent editor of the Journal of Extension used the following quote by de Montaique to reflect his editorial philosophy:

“And one might therefore say of me that in this book I have only made up a bunch of other peoples flowers, and that of my own I have only provided the string that ties them together.”

This quotation accurately represents my input into this publication which summarizes the experiences of others active in educational efforts and regulatory activities concerning oil and gas leasing procedures.

Extension publications from Texas, Oklahoma, North Dakota and Idaho were used extensively as source materials. The bulletin written by Judon Fambrough of the Texas Real Estate Research Center at Texas A & M University was particularly helpful in providing a number of common-sense suggestions for landowners to consider in negotiating an oil and gas lease. A complete list of all references can be found on Page 23.

A number of persons and agency representatives directly involved in evaluating various leasing provisions and situations were invaluable in clarifying leasing procedures and their application to North Dakota. Special recognition must be given to the following individuals who spent many hours reviewing the publication and suggesting revisions to improve its accuracy, quality and usefulness.

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Special thanks must also be given to the following individuals. Their input throughout the writing and review process helped make this publication a more useful document for lay persons not well acquainted with the oil and gas leasing process.

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Don Peterson, NDSU Extension Area Resource Development Agent, Washburn, ND.

The author takes full responsibility for any misinterpretation of recommendations received from persons reviewing all or part of this publication. Also, the recommendations outlined are not intended as a substitute for competent legal advice. Consult your attorney for the interpretation of any lease provisions that apply to your specific situation.

PHOTO CREDITS

The Washburn Leader, Jill Schramm, Photographer. Pages 5, 6, 10, 18 and 21.

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NORTH DAKOTA OIL AND GAS LEASING CONSIDERATIONS

INTRODUCTION

Exploration and development of North Dakota's petroleum resources is occurring at an accelerated rate. Increased prices for crude oil and the development of new technologies make it possible and profitable to drill for petroleum at greater depths. Improved methods have enabled oil companies to produce more petroleum from existing wells. Refined techniques of exploration have helped locate large areas of central and eastern North Dakota having geology favorable for discovery of new oil and gas deposits.

What does this mean for North Dakota? Many landowners who have never thought much about their mineral rights will soon have to make decisions having considerable economic consequences. Also, the "rules-of-the-game" have changed considerably for those landowners whose current leases will soon be up for renegotiation and renewal.

PURPOSE OF PUBLICATION

Providing information to help the citizens of North Dakota better understand the oil and gas exploration and production process and related leasing considerations fits within the objectives of the Cooperative Extension Service. Oil companies will also benefit from this educational effort. An informed public is less apprehensive and easier to deal with, which should reduce the number of disagreements caused by misunderstanding the leasing process and the need for various leasing provisions to protect both the landowner and the oil companies.

Specifically, the purpose of this publication is to:

1. Serve as a general guide to the petroleum exploration and production process for those individuals not yet acquainted with the process.
2. Acquaint non-experts with the more common provisions of an oil and gas lease, relate them to the various steps in the exploration and production process, and explain their legal significance.
3. Detail specific provisions the landowner may wish to include for additional personal benefit and protection.

Because of the legal nature of the leasing process, landowners may be at a disadvantage in arranging for the future use of their mineral resources. Leasing is basically a matter of negotiation, and landowners should be aware of a number of basic factors before beginning these negotiations.

Topics selected for discussion were chosen either because they are of special concern to the landowners or because they are basic to the structure of an oil and gas lease.

NEED FOR LEGAL ADVICE

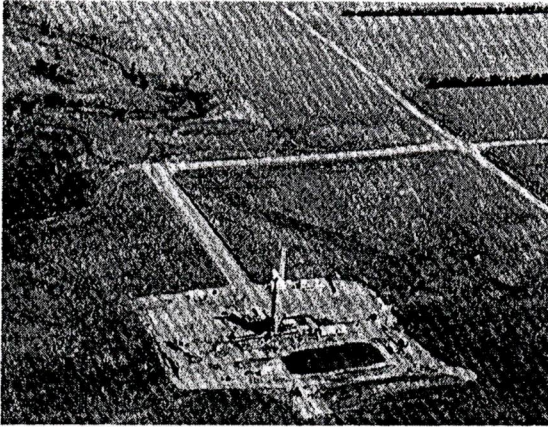
THE MATERIAL PRESENTED IN THIS PUBLICATION IS GENERAL IN NATURE AND SHOULD NEVER BE VIEWED AS A SUBSTITUTE FOR LEGAL ADVICE. Before the lease is signed, an attorney knowledgeable in the oil and gas leasing area should review the lease offered by the mineral developer to determine if it meets the specific needs of the landowner. Many landowners only seek legal advice when a problem arises after the lease is signed. At this point, the lease is a legal contract and resolution of the problem may be difficult.

Always get competent legal advice in drafting a mineral deed, royalty assignment, or deed to land containing a mineral or royalty assignment. Drafting these documents is highly technical and legal matter. Competent legal assistance can avoid possible problems and resulting disagreements and lawsuits.

EXPLANATION OF TERMS

The parties to a lease are called the lessee and the lessor. The lessee is the person or company to whom the mineral rights are leased. The lessor is the landowner and/or mineral owner who is leasing his or her property or some rights in it to another. To keep this publication in layman's terms, the lessee will be called the company and the lessor will be called the landowner.

It is assumed in this publication that the landowner owns all of the mineral rights he or she is interested in leasing. However, one person or group may own the mineral rights and another person or group the surface rights. Where these differences are pertinent, a distinction is made between the mineral owner and the surface owner.



PETROLEUM EXPLORATION AND PRODUCTION

Many residents in western North Dakota are familiar with the process of petroleum exploration and production. However, the nation's energy crisis has produced an upsurge in exploration into new areas of North Dakota where residents are not familiar with the process. Being aware of the steps involved in exploring for, finding, and eventually producing oil and/or gas will aid in understanding the need for some of the provisions which the landowner may wish to include in a future lease for his or her benefit or protection.

Steps in the exploration and production process involve (1) initial interest, (2) leasing, (3) geophysical testing, (4) drilling, and (5) well production.

INITIAL INTEREST

Before a petroleum field can either be explored or brought into production, someone must first take an initial interest in doing so. Establishing this interest can be done in several ways.

1. Research methods such as stratigraphic analysis, geophysical techniques, review of geological maps and literature, and photogeographical mapping coupled with on-site examination of rock strata out-croppings, may indicate if petroleum deposits exist in a particular area.
2. Exploration activity in a particular area is another indication a company not previously involved may invest in exploration to see if other petroleum deposits may have been overlooked.

^{1/} Material in this section was taken primarily from (1) **Local Government and Petroleum Development**, prepared by the Mountain Plains Federal Regional Council and available from the Federal Aids Coordinator's Office, Capital Building, Bismarck, ND 58505, and (2) **Petroleum - A Primer for North Dakota**, available from the North Dakota Geological Survey, University Station, Grand Forks, ND 58202.

3. Initial interest may also be established on a hunch. The hunch is research, but the decision to drill an exploratory well is based on less detailed research information than the other two methods.

LEASING

After establishing an initial interest in a particular area, the next step is to determine who owns the land and, if possible, lease the site to allow further exploration. Leases are acquired by a landman whose primary duty is to secure leasehold interest from the landowners.

County records are searched to determine ownership in a particular area. Not only must the landman determine who owns the land, but who owns the mineral rights as well. After this has been determined, the landman will negotiate the necessary leases with the landowners.

Initial compensation in the form of a bonus and a delay rental payment may be offered the landowner in return for leasing the area of initial interest. These payments will be explained later.

Leases for gas and oil are legal contracts, which for a specified sum of money give the company the right to explore for and to extract oil and gas. Each lease is negotiated and agreed upon individually.

COMPETITION FOR LEASES

The basic geological potential for oil and gas deposits exists throughout most of North Dakota. However, it is unlikely that payments for leases will become competitive until the potential exists for production that can be integrated into established transportation systems. Thus, access to transportation imposes a pattern of leasing activity that spreads outward from discoveries of significant quantities of oil and gas.

Even so, large areas in North Dakota quite distant from existing wells may be leased if they have any production potential at all. Some companies are prepared to invest in the cost of holding large lease acreages hoping that successful exploration by themselves or other companies will cause a portion of their holdings to become extremely valuable.

When a successful wildcat well is drilled a significant distance from previous production, there is likely to be an increase in leasing activity. This also may occur when new information from geophysical testing gives a favorable indication of deposits. However, while drilling information is readily available in local oil industry journals, the results of geophysical tests are seldom made known to the public.

These characteristics of exploration and development affect the intensity of leasing activity. However, neither distance from existing production wells nor lack of recent exploratory activity are reliable indicators of production potential. Interest in developing a particular area is best determined by consulting as many sources as possible including neighboring mineral owners, oil industry journals, and county and state officials charged with issuing permits for various phases of the exploration and production process.

GEOPHYSICAL TESTING

With initial exploration and lease acquisition completed, the company can begin more advanced phases of exploration. They can begin immediately or they may postpone additional exploration to check all information gathered and review additional data. They may want to wait in "frontier areas" to see what other activity develops. Also, on-going activities within the company may take priority over new projects.

Once the time is right, the company will begin further geophysical exploration to obtain more reliable information. Substructures of the earth are studied to localize areas where accumulations of oil and gas might occur.

PERMIT MAN

Prior to exploration, contracts are entered into between the exploration company and the surface owners (and tenants) dealing with compensation for the disruption of land and damage to personal property. Each geophysical crew has a permit man who negotiates the contract. This person also contacts the proper authorities to meet legal requirements, arranges transportation and housing for the crew, and informs them of the location of streams, wells buildings and other areas designated by the surface owner as being sensitive to geophysical testing.

SEISMIC EXPLORATION

The seismograph provides the only direct way of acquiring subsurface structural information without drilling a well. Shock waves, generated at or near the earth's surface, penetrate the earth's crust and reflect back to the surface from the subsurface rock layers. There the reflected signals can be recorded and a printed record obtained on which the depth of various underground formations can be measured. Ideally, such information will reveal patterns of rock formations such as faults, anticlines and folds where oil and gas deposits have a good chance of being found.

Seismic shock waves are usually generated by detonating explosives at the bottom of shot holes 4 to 5 inches wide and drilled 25 to 200 feet in depth depending on conditions. The number of shot holes per mile varies with the type of geophysical information

desired. After the explosives are detonated, a hole-plugging and cleanup crew finishes the operation

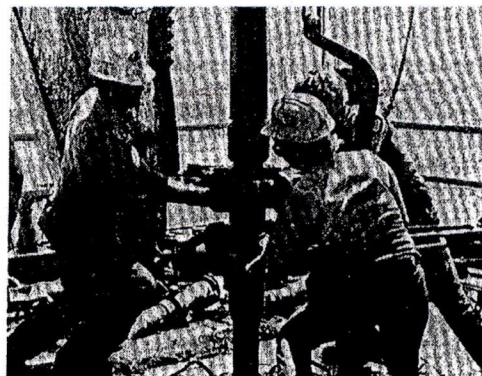
REGULATIONS

Surface owners and tenants should be aware of specific regulations pertaining to geophysical explorations (see Appendix A). If these regulations fail to cover concerns that apply to specific situations, provisions pertaining to these situations should be agreed upon. In the past, most of these agreements have been verbal. A written agreement should be used to protect both parties.

CONSIDERATIONS

While the regulations outlined in Appendix A provide considerable protection for the surface owner (and tenant), the considerations listed below will help reduce further conflicts between the parties involved:

1. Make sure the permit man is aware of areas sensitive to testing.
2. Go over the area to be tested with the permit man and suggest routes to be driven to minimize damage to range and cropland.
3. Geophysical testing companies are usually hired by oil companies to obtain a great deal of information in a short period of time. Even so, attempt to schedule operations to minimize conflicts to both parties.
4. Inform the permit man if any area to be tested is rented to others.
5. Always get the name and address of a company representative to contact if any problems have to be corrected after the testing is finished.
6. Stress the need to clean seismographing equipment before testing to minimize the spread of noxious weeds from one area to another.



DRILLING

Even though leases have been transacted and geophysical studies have been analyzed, other factors must be considered in deciding whether to drill. First, it may cost million of dollars to drill even a dry hole. Secondly, if timing is not right or drilling equipment is not available, the venture may be postponed or even cancelled. Finally, there are non-financial considerations such as potential impact on the environment.

Before drilling is started, state law requires the company to inform the surface owner in writing that the drilling process is about to start. The notice must outline the plan of work and whatever operations are planned by the company. This information is intended to help the surface owner evaluate the effect of drilling operations on the surface owner's use of the property. A form advising the surface owner of his or her legal rights and options must be included with the notice (see Appendix B).

A survey team is an essential part of the pre-drilling preparation stage. They survey the site and stake out where the drilling will take place. They also map out the location of routes to insure access to and from the drilling locations for all necessary heavy equipment and supplies.

Once the surveyors have completed their assignments, work-crews come in with earth-moving equipment to build roads, level off the location, and dig pits and trenches along with the cellar for the rig which will house some of the drilling equipment. When completed, the drilling rig and supplies can be moved in and set into operation.

TIGHTHOLE PROVISION

Landowners should also be aware of the company's right to request a tighthole provision on any well. The provision must be requested, in writing, from the Industrial Commission. If approved, all information concerning the drilling and/or production of the well is kept confidential and will not be released to anyone other than the operator of the well for six months.

WATER USE

Water is essential to the entire drilling process, especially in the preparation of drilling mud. The mud is made up of water, special chemicals and clays. It is used to clean and cool the drill bit, lift rock cuttings to

the surface and maintain a constant pressure in the hole to keep the walls from caving in.

Enormous quantities of water may also be needed for injection into oil-bearing strata during secondary recovery operations. Because of the large demands for water, landowners should pay close attention to any lease provision regarding the use of water for operations (see Resource Use section on Page 18).

WELL PRODUCTION

A decision on whether a well is productive or non-productive is made when drilling reaches the precalculated producing zones. If oil or gas does not come to the surface in the drilling mud, tests can be taken to pinpoint the petroleum containing-formations. Two types of tests normally used are the **drill stem test** and **well logging**.

If further drilling does not result in the discovery of a petroleum deposit, the well is plugged with cement and abandoned. Should a well prove to be productive, well completion and production equipment is set up and the drilling rig is taken down and moved to another site.

Many wells flow naturally because of subsurface pressures. In these cases, a production devise with gauges and control valves, known as a "Christmas tree", is installed on the well head. On nonflowing wells, different types of pumps must be installed.

Once production has begun, the well's productivity is gauged, which allows hourly and daily readings on the volume of gas or oil being produced. These readings are not only important on calculating royalties, they are also important in calculating the life of a well and in prescribing what maintenance must be done to assure reaching the well's optimal productivity.

Periodically, **re-working** operations are performed to insure efficient operation of the well. Work-over crews clean the well by getting rid of fluids and sands which may have gathered in the hole. They may also refracture the well in order to open up the cracks in the formation to allow the oil or gas to flow more freely.

Several storage tanks may have to be built at the well site, and pipelines or tank trucks will be used to get the crude oil or gas to market. Both methods have good points and bad points.

Truck transportation increases traffic on rural roads and bridges which in turn increases local government maintenance costs. Some of these costs are subsidized by oil and gas production taxes, although, in new areas of development, there may be a time lag between when these funds are needed and when they are available.

Pipelines require rights-of-way which sometimes cause problems because they cross or run parallel to public roads. However, pipelines are cheaper in the long run. The size and the life of the oil field usually determines which method will be used.

RELATED LEASE PROVISIONS

The detailed table of contents in this publication points out the many factors which could be pertinent to landowners negotiating a lease. The list is by no means complete nor will all factors pertain to every landowner. However, the need for competent legal advice in evaluating the various alternative should be evident.

Before making a final decision, the landowner and his attorney should work through the possible outcome of each leasing situation. They need to select those lease provisions that will adequately protect BOTH the landowner's interest and the company's ability to carry out an effective development program.

Initially, the landowner must be concerned with how long to lease his mineral interest (Length of Lease), how much will be received in the form of a bonus, delay rental payments, and royalties (Payments Received), and what form of legal protection may be needed (Legal Liability).

A few of the lease provisions related to the drilling process include rights and restrictions on how the surface of the land may be used (Surface Use), and what happens when the term of the lease doesn't match the drilling program (Length of Lease – Drilling Operations Clause). Some of the more important provisions related to production include how to handle gas from a producing well that cannot be sold (Length of Lease -- Shut-in Clause) and how production is divided equitably when a number of wells are pumping from the same oil or gas reservoir (Pooling). Also related are provisions concerning the use of various resources by both the landowner and the company during the production phase (Resources Use).

A sample of a general oil and gas lease can be found on the State Land Department's Mineral Management website.

TERMINOLOGY AND BASIC CONSIDERATIONS

TERMINOLOGY

An understanding of mineral rights and surface rights and the implications of the separation of one from the other are necessary before any discussion of leasing provisions.

Mineral Rights may be defined as the right of ownership of mineral resources which underlie a tract

of land. With the right of mineral ownership is the right to explore for, develop, and produce the mineral resource. In North Dakota, oil and gas are legally treated as minerals just like limestone and coal.

Surface Rights are the rights to use the surface for agricultural purposes, urban development, etc.

Severed Mineral Rights are mineral rights held separately from surface rights. They occur when the owner of both mineral and surface rights legally transfers all or a portion of the mineral rights he or she owns. This severed **mineral deed** is registered with the county register of deeds and becomes a part of the abstract of title to the land involved.

Severance by mineral reservation occurs when someone owning both mineral and surface rights legally transfers the surface rights of the property but retains all or a portion of the mineral rights. These reservations are also recorded and are part of any abstract of title to the land involved.

When the mineral rights are severed from the surface rights, whether by reservation or by deed, the mineral rights are dominant; that is, the owner of the mineral rights has the right to use as much of the surface as is reasonably necessary to explore, produce and transport his or her minerals. However, the mineral rights owner must consider the rights of the surface owner and is required to exercise that degree of care and use which is just consideration for the rights of the surface owner. North Dakota courts have upheld this **dominant estate** doctrine.

WHY LEASE

Any landowner who owns all of the mineral rights has the right to develop any deposits on his or her land. However, few owners attempt to do this because of the tremendous costs involved in exploration and development. Instead, most landowners lease these rights to companies which have the necessary capital and technical know-how for effective exploration and efficient production. As a result, the petroleum industry is based largely on leasing rather than outright ownership of land.

KNOW WHAT MINERAL RIGHTS ARE OWNED

Landowners may not own all of the mineral rights in all of the land they own. Because of possible previous separation of mineral rights from surface rights, it is strongly recommended that landowners put together a list of what land they own and the percentage of mineral rights remaining with each surface title. This provides a starting point for decision-making.

Compiling a list is not easy. Landowners need advice from a competent attorney to interpret the legal wording pertaining to each tract.

TYPES OF OIL AND GAS LEASE FORMS

When mineral rights are leased, the legal rights and duties of the landowners depend in large part upon the terms of the lease. Therefore, extreme care must be taken to insure that the unique needs of each landowner are met.

Each company representative or landman normally uses a predrafted agreement which has proven suitable to them in the past. Most of these lease forms are characterized by brevity and simplicity and are meant to cover most average situations. Since each leasing situation is unique, some of these predrafted agreements are not in the best interest of the landowner. Also, some companies may be using lease forms which are applicable to unique situations in other states but, if applied in North Dakota, could create problems for the landowners.

Most provisions of a lease are negotiable. Even though the company representative or landman soliciting the lease may not have the authority to make changes, this does not mean that certain clauses, or even the complete lease itself, may not be altered. However, the landowner's ability to negotiate more favorable terms will vary in each situation.

IMPLIED COVENANTS

The courts in a number of states have held that an oil and gas lease implies the company is obligated to do certain things. Significant implied covenants are duties (1) to drill an initial well, (2) to protect against drainage of oil or gas from the leased premises by wells on adjoined land, (3) to develop the lease after production by drilling additional wells, (4) to produce and market the product, and (5) to use reasonable care in the conduct of operations. However, North Dakota law is not settled as to which covenants are recognized nor have procedures been established on how to prove a case.

Compliance with these covenants is usually determined by a "prudent operator standard" which means that the company must do what a reasonably prudent operator in the same or similar situation would have done to discharge the duty. Legal interpretation of this standard would depend on the facts established in each individual situation.

STATE REGULATIONS

In North Dakota, the drilling of exploration and development wells and the producing of oil and gas is regulated by the Industrial Commission. Specifically, the Commission has the authority to regulate (1) the drilling, producing and plugging of wells; (2) the chemical treatment of wells; (3) the spacing of wells; (4) operations to increase the ultimate recovery of

wells; and (5) the disposal of salt water and oil field wastes. The Commission also has the authority to limit and to allocate the production of oil and gas from any field, pool or area. Although these regulations provide considerable protection to owners of mineral rights and the related surface rights, lease negotiations are still necessary to cover unique situations not covered by statute or regulation.

No landowner could possibly hope to incorporate all of the following considerations in a lease nor should all of them need to be included. However, each situation is different, and a lease, to be effective, should contain those specific provisions that are relevant.

OIL AND GAS LEASE PROVISIONS

All parties to an oil and gas lease view development as the ultimate goal. To this end, provisions in a lease should permit the oil company freedom to carry out an efficient exploration and drilling program. However, such freedom should be tempered by the interests of society.

HOW TO LEASE MINERAL ACRES

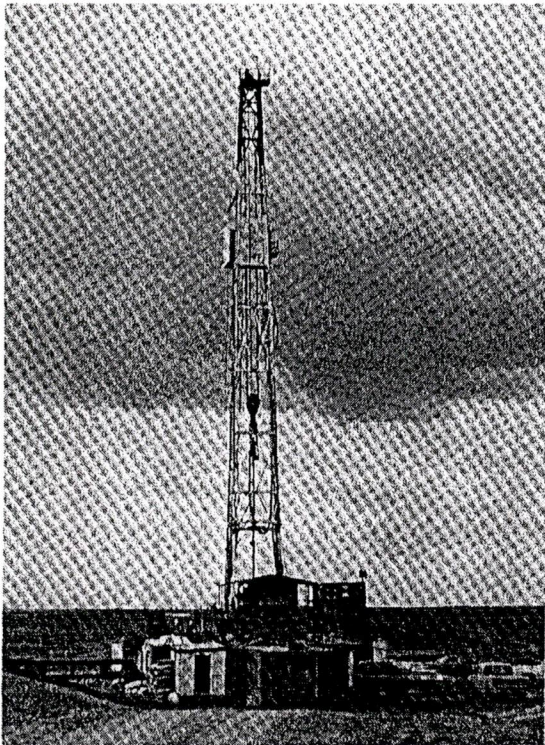
Landowners should exercise due care in deciding how the total number of mineral acres under their control should be leased. This decision, probably, more than any other, will either increase or eliminate many of the problems arising between landowners and oil companies throughout the drilling and production process.

In most cases, the following guideline should be applied in North Dakota. Regardless of how many mineral acres are leased, any land within a given surveyed quarter section (160 acres) should have its own lease. For example, if the landowner had 80 mineral acres in the south half of the northwest quarter in a given section, and another 80 acres in the north half of the southwest quarter in the same section, each quarter section should have its own lease.

This general guideline is followed by the State Land Department and it generally corresponds to the Industrial Commission's policy concerning the spacing of oil and gas wells. The guideline also eliminates many of the problems associated with various lease provisions which will be noted in following sections where applicable.

If this general guideline is followed, any reference to a general pooling clause should be deleted from the lease to keep the company from pooling all of the various leases. Additional explanation of this recommendation is contained on Page 20.

Any mention of a **Mother Hubbard Clause** or a **Coverall Clause** should also be deleted. These provisions could cause problems by allowing the company to claim adjacent acreages when mineral acres are divided and leased in small tracts. Both provisions are normally contained in leases used in Texas. However, some of these leases may be used by Texas companies leasing in North Dakota where there is no practical reason for using these provisions.



WHAT MINERALS ARE COVERED

The granting clause of an oil and gas lease outlines the purpose of the lease and describes the substances which can be explored for and produced. It is normally the opening paragraph of most leases.

North Dakota law stipulates that no mineral lease shall be interpreted as passing any interest to any minerals except those minerals specifically named in the lease. It further states that if the minerals are named, the lease also includes their compounds and byproducts, and "in the case of oil and gas, all

associated hydrocarbons produced in a liquid or gaseous form so named shall be deemed to be included in the mineral named."

Many landowners prefer to lease only for those minerals the company demands and keep the rights to all other minerals for possible later leasing for an additional bonus or rental payments. Therefore, a granting clause including the statement "oil and gas and related hydrocarbons" would be the most practical statement to include and would appear to sufficiently protect the interests of the landowner.

Suggestions for evaluating the granting clause include:

1. To avoid any dispute between the surface and mineral owners, specify that the extraction method used by the company cannot strip away nor substantially destroy the surface except to build those facilities necessary for the drilling and production process. Surface owners should realize all substances lying under the surface do not necessarily belong to the mineral owner.
2. If other minerals are to be named in the lease, consideration might be given to amending the royalty clause (found on Page 12) to list the percentage share the landowner will receive for the production of all substances discovered in commercial quantities. A greater share of the production of one substance than another may be stated as going to the owner. An arbitration clause might be inserted by the owner to cover situations where agreement can't be reached on the differing percentages.

PAYMENTS RECEIVED

In return for giving the company the right to explore for and produce oil and gas, the landowner typically receives compensation in the form of a bonus and delay rental payments before the well is drilled and royalties after production begins

BONUS PAYMENT

When the lease is signed, the company usually pays the landowner an initial cash bonus in so many dollars per acre. The actual amount paid is generally not shown in the lease. Rather, only a nominal consideration is expressed as "one dollar and other valuable considerations." Bonus payments sometimes allow the company to hold the lease for a certain period of time before the company must drill or pay delay rentals.

Competition for leases largely determines the amount of bonus offered. The more intense the competition, the larger the bonus.

Sight Draft

When the landowner signs the lease, the company representative gives the landowner a 30-day sight draft equal to the amount of the bonus. Sight drafts are used to give the company time to recheck the ownership of minerals covered by the lease as well as changes in the standard lease form allowed by the landman subject to company approval.

Upon receiving the sight draft, the landowner takes it to his bank which in turn sends it to the **collection bank** (the company's bank). The collection bank then notifies the company that a sight draft has arrived and they have 30 days from that date to honor the draft. If all is satisfactory, the company sends a check in the amount of the draft to the collection bank and the draft is paid to the landowner through his or her bank. Sight drafts of more or less than 30 days are also used depending on specific circumstances.

To minimize problems associated with the practice of **short-drafting** during the time the draft is clearing, landowners should take **both** the sight draft and the lease to their bank and submit them with instructions that the lease will be released only upon payment of the draft. Short-drafting occurs when an independent landman outbids others for the landowner's lease, records it and then tries to resell it during the 30-day period. If the lease isn't resold, some excuse is given for not honoring the sight draft. When this happens the landowner not only may have missed a chance to lease his minerals to a reputable landman, he must also take the necessary legal steps to cancel the recorded lease.

A number of misunderstandings exist concerning the use of a sight draft.

1. A sight draft is not a check. The draft can only be cashed if the procedure outlined above has been followed.
2. It may take from 35 to 40 days to process a 30-day sight draft. The 30 days start when the collection bank notifies the company the draft has arrived, and it ends when the company sends a check to cover the draft on the 30th day. It may take an additional four to five days for the draft to get from the landowner's bank to the collection bank and return. To insure the collection bank promptly notifies the company that the draft has been received, the landowner should request his or her bank to forward the draft to the collection bank by "Registered Mail - Return Receipt Requested."
3. When the draft is paid to the landowner, the amount received may differ from the amount shown on the sight draft when the lease was signed. This occurs because oil and gas leases normally allow for the payment of a per

acre bonus which is adjusted depending upon the amount of mineral interests actually controlled by the landowner. This can be confusing to the landowner. An alternative is a flat-sum bonus which has been used where the company is fairly sure of the amount of mineral interests controlled by the landowner.

Lease Option

If the landowner feels uncomfortable with a sight draft, an alternative might be a lease option. The option to lease would be given the company in return for an option payment (maybe 10 percent of the bonus) which would be kept by the landowner regardless of whether the company decides to lease. The company could then be allowed sufficient time to check the title, and if they decide to lease, the remaining bonus money (either a flat-sum or a per acre amount) would be paid to the landowner. Competent legal advice should be obtained before using this option.

DELAY RENTAL PAYMENT

For the privilege of delaying the start of the drilling during the primary term of the lease (explained later), the company pays the landowner a delay rental payment. The amount is stated so many dollars per acre and is paid annually. Delay rental payments offered usually stay fairly constant and may be quite low in relationship to the bonus payment.

Under the usual type of lease, the company does not pay delay rentals on a lease anniversary if the company has "commenced a well". This may mean merely digging a slush pit, building a road to a well site, or simply staking out a well location. Leases more favorable to the landowner use the phrase "commence the drilling of a well", which means "spudding in a well" or the actual start of drilling operations.

Once production is obtained and continues, the secondary term of the lease is in effect. The payment of delay rentals is no longer required and royalties are paid to the landowner for his or her share of the production.

If a flat-sum bonus is negotiated with the company, it may also be advantageous to include a flat-sum delay rental payment in the lease.

Rental Depository

A rental depository is the bank designated as the agent acting for the landowner in the handling of delay rentals. However, this bank does not have the authority to bind the owner to extend or ratify a lease by receiving and accrediting a late delay rental payment unless allowed to do so in the lease.

The owner may change this depository by notifying the company who will prepare a **Change of**

Depository to be authorized, signed and returned by the landowner to the company.

THE ROYALTY CLAUSE

From an economic standpoint, the royalty clause is probably the most important clause to the owner because it allocates to the owner a certain portion of the substances produced. The standard royalty on oil and gas for many years was 1/8th share. However, as North Dakota develops into a major oil producer, the 1/6th and 3/16th royalties and other fractions are used to attract mineral owners to lease.

The terms of royalty clauses vary greatly from lease to lease. However, several basic factors should be considered by the landowner.

First, specify which costs, if any, can be deducted from the landowner's royalty payment. The costs encountered throughout the exploration, drilling, production and marketing stages are divided into two categories: (1) those paid entirely by the company, and (2) those shared by the landowner.

Generally, all expenses encountered up through the production stages are paid by the company. Expenses subsequent to production can be either shared or paid entirely by the oil company depending on the terms of the lease.

The shared expenses will depend partly upon where the lease fixes the royalty. If nothing is contained in the lease on this matter, the royalty is implied to be determined "at the well". In such cases, the landowner's royalty payment is free of both production costs and costs subsequent to production. If the lease fixes the royalty "in the pipeline", or "at the place of sale" or at other delivery points, the cost of transporting the production to the point of delivery may be shared. These costs may include such items as compression expenses necessary to deliver the product into the purchaser's pipeline, expenses necessary to make the product salable and the expenses used in measuring production.

Another problem which the landowner should consider is determining how the royalty payment is valued or received. Three methods generally are used.

Determining Value of Production

Market Price

Market price or market value is based on the oil and gas value as reflected by the marketplace, generally at the mouth of the well. In the past, if there was no market at the well, then the market price prevailing in the field was used. If there was no field market, then the value was determined by sales of marketing outlets comparable in time, quantity, quality

and availabilities. And finally, if there were no comparable sales, the actual value of the substance could be used.

The market price method has been quite popular with landowners because it allows the royalty to follow the upward price trend for oil and gas. However, there are some associated problems of which landowners should be aware when using this method.

Sometimes the prices posted at wells or fields are discriminatory and are set artificially and substantially less than the prices paid for comparable minerals at other fields. In such cases, it may be possible to get a higher valuation for the royalty payments but only after a difficult burden of proof has been met by the landowner in a court proceeding.

To avoid problems, the company and the landowner should agree on a formula for determining how the market price or value will be established and this formula should be included in the lease.

Proceeds

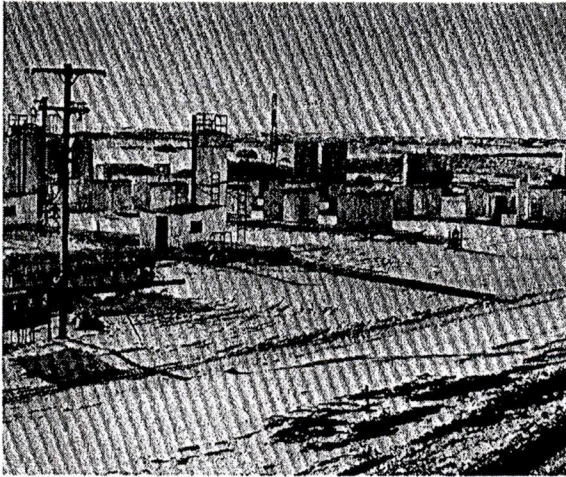
This method establishes the royalty based on the actual revenue derived from the sale of the mineral. As such, the resulting sales price may or may not equal the mineral's actual value as outlined earlier. In the past, the royalties based on **proceeds** have been very popular. This method gave greater flexibility to the company in marketing the product, particularly gas. By committing gas to long-term contracts, the company could insure the landowner of a constant, dependable royalty income over time. The disadvantage is that the resulting proceeds are not immediately sensitive to a rising market.

In Kind

This method presents an excellent alternative for dealing with a lease based on **proceeds**. By inserting an option to take royalties either **in proceeds** or **in kind**, the landowner can get the best of both worlds. Whenever the market price rises above any long-term commitment prices, the landowner can take his or her share **in kind** and seek a market outlet. Whenever the market price falls below any long-term commitment, the landowner's share can be taken **in proceeds**.

The **in kind/in proceeds** alternative is attractive to landowners when selecting a payment option for oil. It could prove to be a good bargaining point, especially if a sufficient volume of oil is involved.

If the landowner has this same option for gas and decided not to sell to the same party the company is selling to, the landowner would have to put in his own gathering line system and possibly his own processing plant. Therefore, the use of an **in kind** gas royalty would be somewhat impractical.



Parts of a Royalty Clause

The royalty clause may have three parts - an oil royalty provision, a gas royalty provision, and a royalty provision for casing-head gas from an oil well from which gasoline may be extracted. The oil royalty clause, unlike the other two, usually authorizes payment of the royalty either in kind (delivery of the royalty oil to the credit of the owner in the pipeline) or in money based on the market value of the oil. As outlined previously, costs of developing a gathering and processing system by a private individual to market his or her share of the gas produced makes the use of an in kind gas royalty impractical. Also, the alternative of having a more lucrative intrastate market for gas does not exist in North Dakota. As a result, gas royalty clauses usually provide only for payment in money.

Special care should be exercised in examining the gas royalty clause. The landowner may want to limit or prohibit the company from deducting certain kinds of costs for processing, treating, dehydrating, compressing, etc., before the company starts paying the royalty.

Cancellation of Lease for Nonpayment of Royalties

North Dakota is one of two states that have a specific statute allowing the landowner to cancel the lease for nonpayment of royalties. The statute allows cancellation, "if the equities of the case require it."

As a practical matter, the statute may not be that useful. If the company missed a royalty payment, but later acknowledged the fact and paid the royalty plus interest, an equitable situation would then exist and the lease most likely couldn't be cancelled. However, if the landowner could prove some kind of bad faith on the part of the company, he may have a case for cancellation.

Recommendations

The following list of factors might also be considered when negotiating a royalty clause.

1. Detail the time, place and frequency royalty payments are to be made. Outline the consequences for royalty payments being missed.
2. Discuss and resolve whether royalties should be paid for wastes due to leakage, fire or other reasons which can be attributed to the company's negligence.
3. Reserve the option to take in kind royalties for oil production if feasible.
4. Determine if the landowner should have access to free gas (see Resource Use section on Page 18).
5. Decide whether the company should have free use of water, oil and gas produced on the leased premises (see Resource Use section on Page 18).
6. As outlined earlier, include differing royalty percentages for substances other than oil and gas that might be included in the granting clause.

Three other factors warrant further consideration when negotiating the royalty clause.

Overriding Royalty Interest

Through negotiations various parties (for example, the geologist who originates the prospect) may obtain an overriding royalty. This interest is paid from the share of production belonging to the company and is usually free of costs of operation by the company.

An overriding (or extra) royalty is sometimes based on a sliding scale with any one of several items used as variables. For example, one royalty could be based on daily or monthly production of less than (x) barrels per day (or month) and another whenever production exceeds this level. Other variables upon which the scale could be based include such things as whether or not the substance is free flowing or having to be lifted by artificial means, or even upon the company's recovery of all or a certain percentage of the production cost from the well.

Generally, the overriding royalty interest and the royalty interests of the landowner are free from the creditors of the company who can only claim against the **working interest** (the company's share of production) unless specifically agreed otherwise.

An overriding royalty may also be created when the person or company leasing the land does not wish to develop the oil and gas and instead sells or "farms out" the lease, reserving an overriding interest. As before, this overriding royalty does not share any of the exploration or production costs.

Royalty Division Order

This document is prepared by the company buying the oil and gas produced and its outlines, in percentages, the share of production which each royalty owner is entitled to receive. When signed and returned by the royalty owner, it is acknowledged by the company to be correct.

Division orders are extremely complex and should only be signed if (1) companies won't pay royalties unless the order is signed, and (2) all the division order does is acknowledge and divide the interest, and the landowner knows that his or her interest is correctly stated. If the order requires the landowner to ratify a gas sales contract, ratify some formula on how royalties are to be paid or determined, etc., competent legal advice should be sought before signing the order.

Time Limit on Royalty Payments

A bill passed by the 1981 North Dakota Legislature requires that interest of 18 percent be paid on royalties not paid within 150 days of the sale of gas or oil produced. Oil companies can normally pay royalties within 90 days after they have sold their first oil from a well, although it may take somewhat longer with the first well in a particular field.

LENGTH OF LEASE

Oil and gas leases are generally divided into two separate time periods.

PRIMARY TERM

The first period, or primary term, is a set number of years negotiated by the parties during which actual drilling operations must begin or delay rentals must be paid. If drilling operations are not started within one year after the lease is signed, it will terminate UNLESS an agreed sum is paid to the landowner. Delay rentals must be paid on each subsequent anniversary date of the lease's primary term if actual drilling operations have not yet begun by that date.

Identification of Delay Rental Payments

Landowners should specify that with any delay rental payment, the company must identify the governing lease and the provisions necessitating the payment. This will aid the landowner in keeping track

of several different leases on their land. Landowners should also keep track of the date by which delay rental payments must be received. Acceptance of a late payment may be interpreted as a ratification and the lease will not terminate.

Production Defined

Drilling must be underway or production established by the end of the primary term or else the lease will end. There have been a number of lawsuits in some oil and gas states regarding what constitutes **production** for the purposes of extending the lease beyond the primary term and continuing it during the secondary term. **Production** in general has been interpreted to mean production in paying quantities over a reasonable period of time. It has been interpreted to mean that the company must have a profit after deducting current operating expenses and marketing costs, but NOT any portion of the drilling costs. There is some question whether or not depreciation must be deducted as an operating expense.

SECONDARY TERM

If production has been established, the lease will continue into its secondary term. Generally, the full clause will read, "This lease will remain in force and effect for a term of ____ years (or months) and as long thereafter as substances covered by the lease are produced."

RECOMMENDATIONS

For the best protection of the Landowner, he or she should consider the following recommendations:

1. Try to keep the primary term as short as possible as this encourages earlier exploration. Considering the current situation, it would be unwise to sign a lease covering a period of more than five years.
2. If the primary term cannot be shortened, try to negotiate a higher annual delay rental payment.
3. Do not amend the standard delay rental clause that stipulates the lease will terminate UNLESS the company pays delay rental payments.
4. If the landowner has a small fractional mineral interest, he may consider requesting a **paid-up** lease. Such a lease benefits both the company and the landowner because both know exactly what the full term of the lease is going to be. Because there are no delay rental payments, the landowner should request a somewhat higher bonus.

EXTENSION OF PRIMARY AND SECONDARY TERMS

Even though the primary term is for a fixed period of time such as three or five years, the lease may not last that long. As mentioned previously, the term clause and the delay rental clause serve reasonably well to satisfy the interests of the company and the landowner regardless of the life of the lease. The landowner is assured that either (1) there will be prompt exploration, or (2) the landowner will receive delay rentals, or (3) the lease will terminate and the landowner will be free to lease the mineral rights to another developer. Likewise, the company is able to reserve the land during the primary term without expensive exploration and is assured of being able to continue the lease after the primary term if commercial production is obtained.

However, these two clauses fail to cover certain difficulties of concern to the company. While general leases have held up in lawsuits more often than not, various **savings** clauses meant to reduce the company's risks regarding disputes over the duration of a lease have become standard features in oil and gas leases.

The primary and sometimes the secondary term of the lease may be extended contractually by (1) drilling operations provisions, (2) shut-in provisions, (3) dry hole provisions, (4) cessation of production provisions, or (5) the Force Majeure clause.

Drilling Operations Clause

This clause is intended to protect the company in situations where a well was started before the end of the primary term but did not become a producing well until after the primary term expired. In this case, the drilling operations clause states the lease will continue and remain in effect just as though the well had been completed before the primary term of the lease expired.

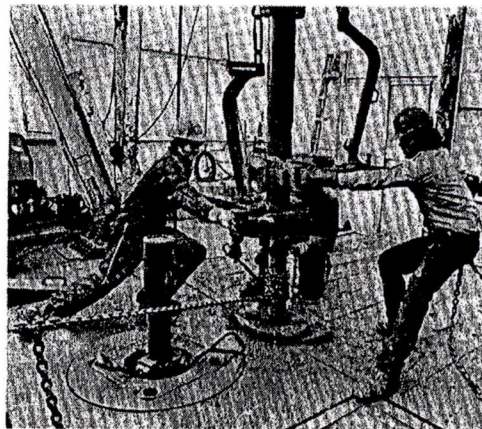
A variation, called a **continuous drilling operations clause**, allows the company to preserve the lease by continuous drilling operations which lead to a producing well even though the producing well is different from the one partially completed at the end of the primary term.

Shut-in Clause

A shut-in clause allows the lease to remain in effect (sometimes during both the primary and secondary terms) whenever gas or oil from a producing well is not, for some reason, being sold or used by the company. If a shut-in well is classified as a producing well under the lease provisions, the lease will not terminate. However, a shut-in royalty or some other stated sum approximating the value of the delay rental payment should be paid each year to keep the lease in effect.

Owners may find it difficult to accept a shut-in provision, especially where no apparent reason exists. However, due to the energy shortage and the high cost of bringing a well into production, shut-in provisions are used rarely. Even so, owners may wish to consider the following alternatives to more clearly outline the possible use of this provision.

1. Make sure shut-in royalties are required during both the primary and secondary terms. Have an attorney familiar with oil and gas leasing procedures check the wording of the shut-in clause to make sure the provision allows the lease to automatically terminate if shut-in royalties are not paid.
2. Place a maximum number of years on the shut-in clause - for example, no more than three years or three years beyond the primary term.
3. Increase the shut-in royalty for each year the gas or oil is shut-in.
4. As an alternative, permit the shut-in to continue after a stated period but only for a specified number of acres immediately surrounding the well. The remainder of the leased area would then revert to the owner. This provision may be qualified depending on the reason for the shut-in. Also, initially leasing the land in smaller tracts would make this provision unnecessary.
5. Outline the circumstances when the shut-in clause may go into effect. Examples may include lack of market, lack of an available pipeline, government restrictions, or other factors mutually agreed upon before the lease is signed.
6. Terminate the shut-in provision automatically whenever a well located on an adjacent spacing unit and completed within the same producing reservoir begins producing and selling gas or oil in marketable quantities.



Dry-Hole Provisions

Suppose the company starts a well during the primary term, but abandons it as a dry hole. If the company does not commence another well within a reasonable amount of time, does the lease terminate or can the company continue the lease by paying delay rentals? If the lease can be continued, when is the next delay rental payment due? Dry-hole provisions are intended to provide answers to these questions.

Dry-hole provisions extend the primary term of the lease, but only in certain instances. Basically the lease will provide that if oil or gas HAS NOT been discovered when a dry hole is drilled, the lease will not terminate even though the primary term has expired if the company renews drilling or re-working operations of the same hole within a certain period of time thereafter. In the event the primary term has not expired and more than the stated period remains, the company may be given two other options if included in the dry-hole clause. The company can either pay the next delay rental payment which comes due a certain number of days after the dry-hole was discovered or commence drilling or re-working operations on or before the same date.

If less than a stated number of months remain in the primary term when the dry hole is completed, the lease will continue in force to the end of the primary term even though the company operations remain idle and no delay rentals are paid.

It is quite possible for the primary term to be extended indefinitely via the dry-hole provisions. If the company has not discovered oil or gas and is in the process of drilling or re-working operations when the primary term ends, the lease will continue in force for so long as the company faithfully renews drilling or re-working operations within a stated number of days after completing each dry hole. However, if a producing well should be subsequently discovered and its production later ceases, the company should be expected to commence the drilling of another producing well resulting from operations within X number of days thereafter or the lease will expire (see Cessation of Production Clause below). The completing of a subsequent dry hole will terminate the lease if the lease so dictates.

Cessation of Production Clause

Suppose production in paying quantities ceases for a prolonged period of time due to some reason other than exhaustion of the oil or gas in the ground. Reasons may include change in government regulations, breakdown of equipment, or a decline in market price. This could happen during either the primary or secondary term.

If it happens during the primary term, can the company still keep the lease in force without having to start drilling a new well or pay a delay rental? If it

happens during the secondary term, does the lease terminate for lack of production? The cessation of production clause is intended to clarify the positions of the company and the landowner in these situations.

Cessation of production provisions are similar to the dry-hole provisions. The main difference is that the cessation-of-production rules apply ONLY AFTER oil and gas have been discovered. Here the lease provides that if oil and gas production should cease for any reason, the lease will not terminate if the company again follows one of the three options described in the dry-hole provisions.

Force Majeure Clause

Some leases may contain another provision meant to protect oil companies from liability and the loss of the lease whenever causes beyond their control halt operations. This provision is the Force Majeure clause. From the company's point of view, this provision has taken on added significance in recent years.

Ten years ago, the company's primary worry was complying with the rules and regulations of the Industrial Commission. Now they also have to deal with township and county zoning regulations, road permits, state bonding requirements, and a host of other factors affecting their operations. Many of these factors are beyond their control.

It appears that the general intent of the Force Majeure provision is similar to the Cessation of Production clause. However, it provides broader coverage in that cessation of drilling operations from causes beyond the company's control is included.

Because of the clause's recent vintage, few court interpretations have emerged. However, if the clause is proposed in a lease, the landowner, with the aid of his attorney, may wish to include the following considerations:

1. Avoid the inclusion of the words "force majeure." Its legal meaning remains clouded.
2. Limit the clause to simple terms. For instance, state, "If drilling, working or production operations are delayed or interrupted for causes reasonably beyond the company's control..."
3. Require a timely written notice any time a sustained work stoppage occurs. Have the notice specify whether the stoppage was related to causes beyond the company's control or to the dry hole, shut-in, or cessation of production provisions of the lease. Furthermore, have the notice contain supportive evidence of the company's reliance on the particular provision.
4. If an unavoidable stoppage should occur during the primary term of the lease, decide

- whether delay rental payments are due and whether the lease term will be extended for the period of the delay.
5. Place a maximum limit on the amount of time the clause can remain in effect.
 6. Determine and state the time frame in which operations must be resumed once the cause is removed.
 7. Do not allow the company to use the Force Majeure provision in situations where they have failed to comply with the rules and regulations of the North Dakota Industrial Commission.

SURFACE USE

With few exceptions, the granting of an oil and gas lease carries with it the implied right to use as much of the surface area as is reasonably necessary to explore and produce the oil and gas. Leases more favorable to the company expand these implied rights and specifically permit a much wider range of surface activities.

RECOMMENDATIONS

Even though the company may be held liable for surface damages, the inconvenience of unwanted structures and entries upon the surface area by the company may be avoided to some degree by the following:

1. Do not allow the unrestricted right to build permanent facilities such as power stations, storage tanks or employee's quarters. State that the prior written consent of the landowner is needed for both the construction and location of such structures and sites.
2. Attach a map of the proposed lease area showing where roads, pipelines, telephone lines, salt water sites and even wells may be located. Depending on the circumstances, additional compensation may be in order for road right-of-way. For convenience, landowners generally do not permit a well within some stipulated distance of a dwelling (usually 330 ft.).
3. Provide that all underground pipelines and telephone lines must be buried below plow depth where cropland is involved. If exceptions to this provision are necessary, permit them only after getting the landowner's written consent.
4. Direct the company to use the **double ditch** method for laying any pipe if the area above the pipeline is to be cultivated or grazed. **Double ditching** requires placing the top soil on one side of the ditch and the subsoil on the other. When backfilling, the subsoil is replaced first.
5. Indicate whether the oil company's structures and equipment must be removed or be

forfeited when the well is abandoned. If they are going to be removed, a reasonable amount of time should be allowed.

6. When a well is determined to be unproductive, procedures approved by the State Industrial Commission must be followed in plugging the well. These procedures include restoring the drill site as nearly as practical to its original condition. Similar procedures apply to pits built to contain drilling mud and the accumulation of drill cuttings during the drilling process. If these general regulations fail to cover unique individual circumstances, provisions for an agreed upon level of reclamation should be contained in the lease.
7. State regulations require that provisions must be made by the company to prevent livestock from gaining access to pits used to store saltwater liquids or brine. If additional fences, gates and cattle guards are necessary, identify in the lease who is responsible for the construction and maintenance of these items.

North Dakota law prohibits companies from allowing saltwater liquids or brines from flowing over the surface of the land or into streams. State law also authorizes the Industrial Commission to regulate underground disposal of oil field brine. Any company planning to dispose of salt water in underground formations must obtain a permit from the Commission. They must also follow accepted storage procedures and report monthly regarding amounts of salt water injected, injection pressures, etc.

CONJOINTLY OPERATIONS

The right of the oil company operating conjointly with neighboring lands is included in most standard lease forms and is sometimes abused. This provision means the company may build roads and pipelines across the landowner's land to be used to operate oil wells on an adjoining farm. Other provisions may be inserted to include any small adjoining tracts which the landowner owns, or to permit the oil company to drill oil or gas wells on adjoining land without requiring counter-drainage.

While these powers are often necessary, the landowner may wish to restrict their use to protect his or her own interest. The lease could provide that these powers be granted by separate agreement when and if they would be of interest to both parties.

DAMAGES

When the company goes beyond what is reasonably necessary in the drilling process and negligently injures the surface area, the company becomes liable to damages.

<http://www.ag.nd.gov/Opinions/2007/Letter/2007-L-07.pdf>

North Dakota law contains specific requirements concerning surface damages and disruption payments both for the surface owner and for others affected by the drilling process. Regulations pertaining to the mineral developer's responsibility to the surface owner include:

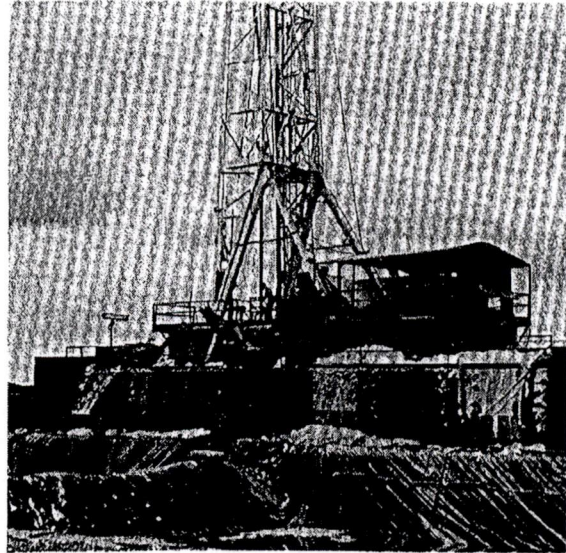
1. The mineral developer must pay the surface owner for loss of agricultural production and income, lost land value, and lost value of improvements caused by drilling operations.
2. The amount of damages may be determined by any formula mutually agreeable between the surface owner and the company.
3. When determining damages, consideration shall be given to the period of time during which the loss occurs and the surface owner may elect to be paid damages in annual installments over a period of time.
4. The payments shall only cover land directly affected by drilling operations.
5. Damage payments to the actual surface owner cannot be assigned to others except to a tenant of the damaged surface area.

The company also has a responsibility to others affected by drilling operations.

1. The company is responsible for all damages to persons or property, both real and personal, from the lack of ordinary care by the company and from a nuisance caused by drilling operations.
2. To receive compensation, the injured party must notify the company of the damages within two years after the injury occurs.
3. Within 60 days after the company receives notice of damages, the company must make a written offer of settlement.
4. If the settlement offer is unsatisfactory or no reply is received, the injured party may bring action for compensation in court.
5. If the award offered by the court exceeds the original offer of the company, the court will award the injured party reasonable attorney fees and court costs.

In addition to the protection provided by state law, the landowner may also want to consider the following factors when negotiating the lease:

1. Describe the method to be used in determining the extent of damages suffered. In the event the parties cannot agree, provide for arbitration or some other means of resolving the dispute.
2. Resolve beforehand how payments will be distributed among respective surface owners and/or tenants of the surface area.



RESOURCE USE

COMPANY'S FREE USE OF RESOURCES

Related to the implied right to make reasonable use of the surface of the leased land, a company has the implied right to use other available resources reasonably necessary for oil and gas operations.

Water is essential to the entire drilling and production process. As outlined previously, water is used in the preparation of drilling mud. Also, modern oil production technology includes a secondary recovery technique called **water flooding**. Water is injected into a partially depleted oil bearing formation to wash the oil out of the rock into the well. Increased use of this technique could interfere with the supply of water to the owner's irrigation or domestic wells.

Because of these large demands, landowners should pay close attention to any provisions providing free water, oil or gas to the company for operations. Particularly in areas where water is scarce, certain limitations might be placed on these rights. The following suggestions may be helpful.

1. If free water, oil and gas privileges are granted to the company, stipulate whether the substances may be used for operations conducted both on and off the leased premises. You may want to limit the free use of water to just salt water. Denying the company free use of gas for on-site production may be difficult.

2. If the land should contain a central supportive device, such as an oil-gas separator, prorate the free use of oil and gas needed to run the separator according to the amount of production on the land.
3. Do not allow the company to take water from wells, tanks, ponds or reservoirs without permission or compensation.
4. Stipulate that any water used by the company cannot restrict the supply of water for domestic, livestock or agricultural purposes.
5. If recovery measures are undertaken by the company involving floodwater operations, deny the use of any water suitable for drinking. State that such water must come from non-fresh sources.
6. If water is to be purchased, state how the market price will be determined.
7. Note in the lease whether the land can be used for underground storage of gas or oil.

LANDOWNER'S USE OF RESOURCES

There may be instances where landowners can benefit from the use of equipment utilized in the drilling process or from the use of water and gas produced. Landowners might consider including the following provisions in the lease:

1. State in the lease if and when the landowner should have access to free gas. Many leases allow the owner the free use of gas for domestic purposes. Less common, but perhaps desirable for many farm operators, is a so-called irrigation gas clause, which allows the owner to receive at an agreed price such gas as is necessary to operate pumps for irrigation purposes.
2. Require the company to notify the landowner of all water-bearing formations encountered in the drill hole. If the well is not a producer of oil or gas, give the landowner the option to require the company to leave as much casing and tubing in place as is required to withdraw any remaining gas or extract fresh water for domestic or agricultural purposes. When the well can safely be used as a freshwater source, the landowner is required to write to the Industrial Commission and indicate that he wishes to use the well for freshwater and assume all liability for such use. This notice will allow the Commission to relieve the company of their legal responsibility to plug all wells not producing oil or gas.

POOLING

Pooling is a communitization or joining together of two or more surface tracts in an oil field whereby the

various owners or mineral interests agree to share the expected benefits from a specific oil reservoir located under their land. In any given oil field there may be more than one oil reservoir at one level, or there may be a number of separate oil reservoirs stacked at different levels.

Pooling is necessary because much of the oil in a reservoir or related spacing unit could be removed by a single well on just one of the tracts within the unit. This would be harmful to the owners of the other tracts who may also wish to drill a well to protect their interests. However, drilling additional wells would be harmful and unnecessary. An alternative is to form a pooling arrangement whereby the owners of interest within a specific area share in the production from one or more wells according to the proportion of total mineral interests owned within the area.

Landowners may be subject to both voluntary and compulsory pooling arrangements. For example, state regulations prohibit the drilling of more than one well to the same oil reservoir on a spacing unit unless an exception is made by the Industrial Commission. However, the owners of interest in a specific oil reservoir under an area larger than the initial spacing unit, and located outside of an area that has not yet been pooled, can voluntarily agree to pool their interests and share proportionately in the production from that reservoir.

Voluntary pooling requires the free consent of the owners of mineral interests and is generally found in the context of most lease forms. The reason the pooling clause is included is to minimize any potential problems for the company when it comes time to pool.

STATE REGULATIONS

Sometimes it's impossible to get all of the interest owners to agree to a particular pooling arrangement. When this happens, any of the persons owning an interest in the spacing unit may apply to the Industrial Commission for an order that will pool all interests.

The Commission must first hold a public hearing on the matter after public notice has been given. After the hearing, the Commission will issue the pooling order which must provide for the just and reasonable division of the proceeds from production from wells in the spacing unit among all of the interest owners. Any new well drilled in this pooled area or any other pooled area must conform to the spacing authorized by the Commission. See Appendix C for a summary of minimum spacing requirements.

POSSIBLE PROBLEMS

By entering either type of pooling arrangement, the landowner may find the interpretation and application of some of the original lease provisions substantially changed. For example, it appears that a typical

pooling clause could enlarge the company's implied right to make reasonable use of the leased land to enable the company to use water from that land for the production of oil and gas from a well on other land included in the pooled unit. Also, the owner on whose land the well is situated could experience a heavy burden of surface use, yet the owner will receive only a proportionate share of the royalties. If specific damages as a result of this situation are not covered by North Dakota law pertaining to surface damages and disruption (see section pertaining to the Damage Clause on page 17), the owner may want to add specific provisions in the lease.

It also appears that by establishing a pooling arrangement, the company may be able to exercise a great deal of control over a considerable amount of leased land by drilling and establishing production on only a small part of the total pooled area. This problem will be addressed in the next section

RECOMMENDATIONS

Obviously, there is little the landowner can do to avoid compulsory pooling. However, the landowner can exercise caution in granting the company the unrestricted right to pool the leased mineral interests. The following suggestions may be helpful.

If the landowner is successful in following the general rule pertaining to leasing small tracts (see Page 9), eliminate the general pooling clause from the lease. If this isn't done, the company will be able to exercise their rights under the pooling clause and pool all of the various small leases.

General pooling provisions usually have language which allows the company to pool the mineral interests covered by the lease with other land or leases in the immediate vicinity for the production of gas and oil when in the company's judgment it is advisable to do so. The problem with granting this broad authority is that after pooling, any production, drilling or re-working operations on a well located on any portion of the pooled land could be interpreted as being undertaken on any part of the leased land.

By including the leased parcels in a pool, the company may be able to eliminate the need for paying delay rental payments, reduce the proportionate share of royalties to the respective landowners, and still maintain all of the leases by drilling and establishing production on any part of the pooled area. The "active" well need not be located on any portion of the land originally leased in small tracts, it could be located on adjacent land in a pooled unit in which the company included the leased land.

If larger acreages are leased, the landowner may want to negotiate a **Pugh Clause** which provides for the severance of the lease into separate tracts whenever less than all of the leased land is included in

a single pool or unit. However, a **Pugh Clause** is difficult to negotiate, and initially leasing the mineral interests in small tracts is a suitable and much more realistic alternative.

As mentioned earlier, there may be several separate oil reservoirs stacked at different levels under the same surface area. The insertion of a **Pugh Clause** that provides for the severance of the lease into separate producing formations or levels when only one formation is included in a single pool or spacing unit could be beneficial. However, this type of clause, especially in wildcat areas, would be extremely difficult, if not impossible, to negotiate. As before, leasing the surface area in small tracts is a more realistic alternative and should take care of most of the problems a landowner might encounter.

UNITIZATION

Similar to pooling, the Industrial Commission also regulates the joining together of various mineral interests in a specific reservoir to increase the ultimate recovery of oil and gas. This process may involve pressure-maintenance or repressuring operations, cycling operations, etc.

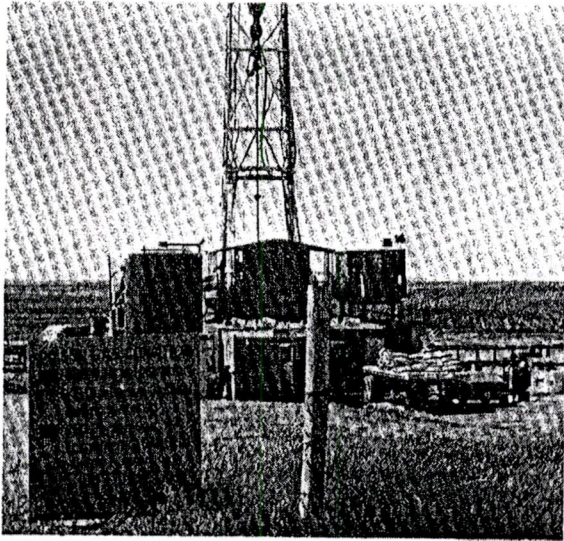
For example, there may be four wells in a 160-acre unit. The owners of interest may agree to shut down one well, decrease production in two wells, and increase production in the remaining well if this is the best method of getting the most oil or gas from the total 160-acre unit. Another method might be for the owners of interest to agree to drill a new well in the center of the four wells and pump water into the old wells hoping to force more oil to the new well.

In general, the orders set forth by the Commission pertaining to a requested plan of unitization must protect and safeguard the respective rights of the persons affected. More specifically, the plan must prevent waste and, with reasonable probability, result in the increased recovery of more oil and gas from that reservoir than would otherwise be recovered. Also, the costs of unitization must not exceed the value of the additional oil and gas recovered.

Any owner of interest may enter a plan for unitization and request the Commission to approve it. Before the Commission will approve it, at least 60 percent of the owners of interest must sign or ratify the unit agreement.

LEGAL LIABILITY

Landowners should seek competent legal advice concerning their legal liability throughout the exploration and production process. Some specific areas of concern include:



ASSIGNMENT CLAUSE

Typically leases contain a provision permitting both the landowner and the company the unrestricted privilege of assigning their rights under the lease. To a large extent these provisions are for the company's benefit.

A customary practice in the oil and gas industry is for independent landmen to lease a large area and assign (sell) it to an oil company. Consequently, the ultimate developer-producer may not necessarily be the original company or person leasing the mineral rights. At times the landowner may find the original lease tract being subdivided among several developers. To keep better informed about such changes, the landowner may seek to incorporate some of the following suggestions in his or her lease:

1. Deny the right of assignment without first securing the landowner's written consent. If this is not feasible, state that any assignment is not binding upon the landowner until he or she is duly notified in writing. In either case, the landowner should keep a permanent record of each new assignee for his or her files.
2. Do not release the original company or person leasing the mineral rights from liability for a default on any assigned portion of the lease or leased area. State that a default on any transferred part of the lease is a default on the whole.
3. Provide that accompanying each payment there must be an identification of the governing lease (or assignment thereof) and the provisions of the lease for which payment is being made.

WARRANTY CLAUSE

Leases generally will contain provisions binding the landowner to defend interest in, or title to, the leased premises should a dispute ever arise over ownership. This is known as the warranty clause.

To avoid any possible expense in a legal action, landowners should omit any language which infers they will warrant to defend title to the land. Since most oil companies or landmen conduct preliminary investigations as to the ownership of mineral interests prior to any lease negotiations, and conduct detailed investigations before paying the initial bonus, the warranty clause shouldn't be necessary.

OTHER LEGAL CONSIDERATIONS

Time Limit to Settle Violations

The landowner may want the lease to provide that if the company does not correct any violation of an agreement contained in the lease within 30 days after the landowner gives written notice, the company should pay reasonable attorney fees and reasonable investigative costs incurred by the landowner in preparing the case for trial.

Ambiguous Terms in a Lease

Landowners should also be aware of the North Dakota Supreme Court decision which states that persons writing a lease as a normal course of their business have an obligation to avoid ambiguities about the terms of such leases. An ambiguity arising after signing cannot be interpreted in favor of the company since the landowner does not ordinarily have the specialized knowledge to avoid such ambiguities at the time of signing.

Security Against Claims

Landowners may want to require the company to give security against future loss, save and hold the landowner harmless from all claims, demands, and causes of action stemming from activities undertaken by the company or the company's employees, agents, contractors and subcontractors during operations conducted on the leased premises. If possible, require the company to post bond and carry comprehensive liability insurance of a specified amount as added security from such claims.

TOP LEASING

When oil was first discovered in North Dakota in 1951, large tracts of land throughout the Williston Basin were leased. These 10-year leases were renewed, bought and sold in 1961 and 1971. In 1981, the process is continuing, but with a major difference - top leasing.

Top leasing is a highly competitive practice whereby oil and gas minerals already legally bound under an existing lease are leased again. In general, this method of mineral leasing is used in areas where existing leases will expire in the near future.

An advance payment, usually considered part of the bonus, is offered the mineral owner when the top lease is signed. When the existing lease expires, the new lease becomes binding and the balance of the bonus money is paid. The top leasing mineral company will lose the advance payment if the company owning the existing lease decides to drill for oil or gas before the lease expires.

In areas of intense competition for leases the primary term may be as short as 18 months to three years. When negotiating these short term leases, the company may at the same time negotiate a top lease for the same tract thereby assuring the company of a longer period of time in which to develop the tract.

Top leasing benefits the landowner in that increased competition for leases enhances his or her bargaining position. Mineral companies also benefit. The practice allows them to lease certain areas showing a high potential for oil and gas production without waiting for existing leases to expire. It also allows the company's land crews to be more efficient in covering a given area in a shorter period of time.

Top leasing does not mean that the lease now in effect is automatically renewed for the new lease period. Negotiations again take place to make sure the new top lease meets the needs of the company while providing adequate returns and protection for the landowner. Input from an attorney familiar with oil and gas leasing procedures is strongly recommended in these negotiations.

OWNERSHIP PATTERNS AND MINERAL RIGHTS

CO-OWNERSHIP

If the mineral rights have been divided by either will, deed, or inheritance laws, each owner becomes a **tenant-in-common** of an individual interest in the minerals. Each **tenant-in-common** must sign a lease, but each is free to bargain for as large a cash bonus or other benefits as can be obtained. While it may be advantageous for all to lease to the same company, there is no need for them to do so.

Mineral interests held by individuals as **joint tenants with the right of survivorship** can be handled in the same way. The **joint tenants** are free to bargain separately or collectively. If three brothers owned the mineral rights as **joint tenants**, each may have a different lease pertaining to their one-third share of the minerals.

If two of the three brothers agree to the same lease, the company may approach the third brother and ask him to ratify the lease agreed to by the other two brothers. By signing the **Ratification of an Existing Oil and Gas Lease** form, the brother agrees that if he inherits the other brother's shares of the jointly owned property before the lease expires, he will accept the provisions of the lease already on that property.

When the mineral rights are owned by several persons, difficulties can arise in getting them all to execute a lease. This could happen if one person has disappeared, is a minor, refuses to execute the lease, or for some reason cannot execute the lease. North Dakota law permits the owners of one-half or more of the oil and gas, or the owners of leases covering one-half or more of the minerals under contract, to ask the court for an order allowing them to develop the oil and gas. This is done to protect the interests of the majority owners.

When this is done, all owners, both known and unknown, are made parties to the action. If the petition is approved by the court, nonsigning owners are guaranteed their proportionate benefits from the lease.

LIFE ESTATE

Leasing could become more complicated when land is subject to a life estate. Life tenants and remaindermen must usually join in executing or ratifying an oil and gas lease. They may agree to divide the proceeds in the lease or in a separate agreement. In the absence of such an agreement, the law provides a formula for computing the share of each one.

GUARDIANSHIP OR TRUSTEE

Leasing complications also arise when mineral rights are controlled by a guardian or trustee. Generally, a court order is needed to allow the guardian or trustee to execute an oil and gas lease.

WHEN AND TO WHOM SHOULD LANDOWNERS LEASE?

Landowners may incur some minor risks and inconveniences by leasing their oil and gas rights. However, if oil and gas are found, the disadvantages will likely be small compared to the royalties received. Consequently, the decision is not whether to lease but rather when and to whom.

WHEN TO LEASE?

With little or no competition for leases, the landowner must decide whether to accept the current offer or hold out until competition results in higher

delay rentals and bonuses. If the initial offer is accepted, the landowner may give up the chance of leasing at a larger bonus and higher rentals during the term of the lease. If the landowner decides to hold out for higher returns, he or she may not get an offer if competition doesn't develop in the area.

Where there is little competition, most landowners are interested in getting exploration started in the area and many of them can be expected to sign leases at the first opportunity if the lease is equitable and meets their needs.

TO WHOM SHOULD LANDOWNERS LEASE?

If there is competition for leases, landowners may have a chance to choose between two or more prospective companies. Comparing the merits of the prospective companies, the lease rates and bonuses offered, and various provisions of the lease will help decide.

However, there are other factors to consider:

1. Landowners should deal with a well-financed, well-managed company that has shown the ability to carry out an effective exploration and development program. However, this may be difficult to determine because companies often obtain leases through brokers.
2. If lease provisions are about the same, landowners should try to deal with the broker or company that has leased the most land in the area. Development may be delayed if two or more companies hold inter-mingled leases.
3. If landowners own only part of the oil and gas rights in a tract, they should try to lease to the same broker or company holding the leases from the other mineral owners. This will avoid problems that often arise when two or more companies control fractional interests in the same tract.

Once signed, an oil and gas lease becomes a binding contract between the landowner and the company. Therefore, landowners should avoid making hasty decisions. They should gather all relevant information and find out what their neighbors have been offered and what they decided to do.

When the decision can no longer be delayed, the landowner should think through the probable outcome of each decision before making a choice. They should also notify the holder of any mortgage against the land before signing the lease. Some mortgages stipulate that income from mineral leases must be used to retire the mortgage debt.

Landowners should carefully check bank references and other credentials of the broker or company representative before signing any document.

They should also discuss their individual situation with their attorney, tax consultant, or credit source.

SUMMARY

This publication presents a summary of the oil and gas exploration and production process along with related leasing considerations. As mentioned before, NO LANDOWNER COULD POSSIBLY HOPE TO INCORPORATE ALL OF THESE CONSIDERATIONS IN A LEASE NOR SHOULD ALL OF THEM NEED TO BE INCLUDED. However, each situation is different and a lease, to be effective, should contain those lease provisions that pertain to each landowner's unique circumstances.

The need for and the importance of the various lease provisions outlined in this publication could change substantially because of constantly improving technology, State and Federal legislation, and future court decisions. Even so, the information presented should alert landowners to various alternatives and promote a more frank discussion between the landowner and the company before any contracts or leases are signed.

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APPENDIX A

GEOPHYSICAL EXPLORATION REQUIREMENTS CHAPTER 38-08.1

38-08.1-01. DEFINITIONS. As used in this chapter, unless the context requires otherwise:

1. "Commission" means the industrial commission.
2. "Geophysical exploration" means any method of obtaining petroleum-related geophysical surveys.
3. "Operator of the land" means the surface owner or the surface owner's tenant of the land upon or within one-half mile [.80 kilometer] of the land on which geophysical operations are to be conducted.
4. "Permitting agent" means a person who secures a permit from an operator of the land to conduct geophysical exploration activities.
5. "Person" means and includes any natural person, corporation, limited liability company, association, partnership, receiver, trustee, executor, administrator, guardian, fiduciary, or other representative of any kind, and includes any department, agency, or instrumentality of the state or of any governmental subdivision thereof.

Source: N.D. Century Code.

38-08.1-02. ENFORCEMENT BY COMMISSION - PERSONS REQUIRED TO COMPLY WITH CHAPTER. Notwithstanding any other provision of this chapter, the commission is the primary enforcement agency governing geophysical exploration in this state. Any person in this state engaged in geophysical exploration or engaged as a subcontractor of a person engaged in geophysical exploration shall comply with this chapter; provided, however, that compliance with this chapter by a crew or its employer constitutes compliance herewith by that person who has engaged the service of the crew, or its employer, as an independent contractor.

Source: N.D. Century Code.

38-08.1-03. DEEMED DOING BUSINESS WITHIN STATE - RESIDENT AGENT. A person must be deemed doing business within this state when engaged in geophysical exploration within the boundaries of this state, and shall, if not already qualified to do business within the state under chapter 10-19.1, prior to such exploration, file with the secretary of state an authorization designating an agent for the service of process.

Source: N.D. Century Code.

38-08.1-03.1. SURETY BOND - CERTIFICATE - RELEASE.

1. A geophysical exploration contractor desiring to engage in geophysical exploration in this state shall file with the commission a good and sufficient surety bond in the amount of fifty thousand dollars if the contractor intends to conduct shot hole operations or in the amount of twenty-five thousand dollars if the contractor intends to use any other method of geophysical

exploration. Each subcontractor engaged by the geophysical exploration contractor for the drilling or plugging of seismic shot holes must file with the commission a good and sufficient surety bond in the amount of ten thousand dollars. The bond must be in a form prescribed by the commission and must indemnify all owners of property within the state, including the state and its political subdivisions, against physical damages to property which may result from geophysical exploration and the plugging of drill holes. The bond must cover all geophysical exploration and plugging operations conducted within one year of the date the bond is issued and must be automatically renewed unless the commission and the person covered by the bond receive notice sixty days before any anniversary date of the surety's intent not to renew the bond. If the surety does not renew the geophysical exploration contractor's bond, the surety's liability under the bond ceases six years from the date that geophysical exploration or reclamation covered by the bond was last conducted in the state. If the surety does not renew the drilling or plugging bond, the surety's liability under the bond ceases two years from the date the drilling and plugging covered by the bond was last conducted in this state. A person required to post a bond under this subsection may post cash or a certificate of deposit in lieu of the bond under rules adopted by the commission.

2. The aggregate liability of the surety on the bond may in no event exceed the amount of the bond.
3. Upon filing the bond required by this section and presenting a certificate of authority to transact business in this state issued under section 10-19.1-136, a certificate of incorporation issued under chapter 10-19.1, or some other certificate issued by the secretary of state showing the name of the person designated as resident agent for service of process, the commission shall issue to the person desiring to engage in geophysical exploration or plugging operations or any subcontractor of that person a certificate showing that the bond has been filed and showing the name and address of the surety company and the name of the person designated resident agent for service of process.
4. The proceeds of a surety bond become the property of the commission or the cash or certificate of deposit posted in lieu of a surety bond may not be returned to that person if the principal or person posting the bond, cash, or certificate of deposit fails to comply with this chapter and rules adopted by the commission under this chapter. This must be determined by the commission after notice and hearing in accordance with rules adopted by the commission. Notice of the hearing must be given to the principal and surety on the bond or to the person posting the cash or certificate of deposit by mailing a copy of the notice of hearing and a copy of a complaint, stating the grounds for forfeiture to them, filed by the commission. This must be done by certified mail, return receipt requested, and addressed to their last known address listed with the commission. If the principal or surety or person posting the cash or certificate of deposit has a defense to, or otherwise wishes to contest the complaint of the commission, that person must file a written statement or answer setting forth the defense with the commission at least three business days before the commission hearing. Any defense or reason for contesting the complaint is waived if that person fails to do so. The commission may treat the failure to file a defense or reason to contest the complaint or the failure to appear at the hearing as default by the party. If the commission determines the principal on the bond or the person posting the cash or certificate of deposit as security has complied with this chapter and rules adopted by the commission under this chapter, including the proper plugging of wells and seismic holes and reclamation of the surrounding affected area, with respect to all operations secured by the bond, the commission shall release the obligation of the bond or return the cash or certificate of deposit upon its next anniversary date.

Source: N.D. Century Code.

38-08.1-04. APPLICATION FOR PERMIT TO ENGAGE IN GEOPHYSICAL EXPLORATION. Any person desiring to engage in geophysical exploration before actually engaging in the exploration, shall file an application for a permit to engage in geophysical exploration with the commission. The application for a permit for geophysical exploration must include the following:

1. The name, address, and telephone number of the person intending to engage in geophysical exploration or plugging operations and the name and telephone number of any local representative who may be contacted by the commission concerning geophysical exploration activities.
2. The name, address, and telephone number of any subcontractors, including drilling and plugging subcontractors, to be employed by the person intending to conduct geophysical exploration or plugging operations.
3. The name and address of the resident agent for service of process of the person intending to engage in geophysical exploration.
4. The date upon which geophysical exploration is to begin.
5. The approximate number and depth of any drill holes and the specific location of any drill holes or a description of the property on which the geophysical exploration is to be conducted described by township, range, section, and quarter section.
6. A fee of up to one hundred dollars.

The person making application for a geophysical exploration permit shall file an amended application whenever there is any new information or a change in the information contained in the application on file with the commission.

Source: N.D. Century Code.

38-08.1-04.1. EXPLORATION PERMIT.

1. Upon filing a complete application for permit to explore pursuant to section 38-08.1-04, the commission may issue to any person desiring to engage in geophysical exploration a "geophysical exploration permit". A person may not engage in geophysical exploration activities in this state without having first obtained a geophysical exploration permit from the commission.
2. The permit must show, at a minimum:
 - a. The name of the person.
 - b. The name and address of the resident agent for service of process.
 - c. That an application to engage in geophysical exploration has been duly filed.
 - d. That a good and sufficient surety bond has been filed by the person, naming the surety company and giving its address.
3. The permit must be signed by the director of the commission's oil and gas division or the director's designee. The permit is valid for one year.
4. Within seven days of initial contact between the permitting agent and the operator of the land, the permitting agent shall provide the operator of the land and each landowner owning land within one-half mile [.80 kilometer] of the land on which geophysical exploration activities are to be conducted a written copy of section 38-08.1-04.1 and chapter 38-11.1.
5. The permitting agent shall notify the operator of the land at least seven days before the commencement of any geophysical exploration activity, unless waived by mutual agreement of both parties. The notice must include the approximate time schedule and the location of the planned activity.

6. The permit or a photostatic copy thereof must be carried at all times by a member of the crew during the period of geophysical exploration and must be exhibited upon demand of the landowner or tenant operator or county or state official.
7. The permit holder shall notify the county auditor or the auditor's designee at least twenty-four hours, excluding Saturdays and holidays, before the permit holder commences geophysical exploration in the county. Notice must include the approximate time schedule and location of the planned activity.

Source: N.D. Century Code.

38-08.1-04.2. NOTIFICATION OF ISSUANCE OF PERMIT - REVOCATION - SUSPENSION. The commission shall immediately forward notice of the issuance of a permit to the board of county commissioners of the county in which the lands are located. The commission may revoke the permit of any person engaging in geophysical exploration upon a showing that that person has violated any applicable requirement pertaining to geophysical exploration. The commission shall notify that person, by the most effective written means, of the permit revocation. Upon notification, the person engaging in geophysical exploration may, within fifteen days, request a hearing before the commission on the matter. The commission shall either affirm, modify, or deny the permit revocation. The commission may also suspend the permit temporarily in those cases where climate and physical conditions are such as to cause harm, damage, or undue stress to roads, bridges, pastures, crops, or other physical features. For these same reasons, a board of county commissioners, upon notice to the permit holder and the commission, also may suspend, for not longer than forty-eight hours, a permit for operations within the county.

Source: N.D. Century Code.

38-08.1-05. DUTY TO FILE RECORD SHOWING WHERE WORK PERFORMED. Within thirty days following any calendar month in which geophysical exploration is begun by any person within this state, such person shall file with the commission and shall send to the owner or occupier of any land upon which work is begun, a record showing the township, range, section, and quarter section in the county in which such work was performed and the date upon which such work was commenced. The notice also must include the actual shot point location and the amount of explosive charge, if any, in each drill hole.

Source: N.D. Century Code.

38-08.1-06. DUTY TO PLUG DRILL HOLES - PENALTY.

1. Drill holes must be plugged and abandoned as required by this section.
2. The seismic company responsible for the plugging and abandonment of seismic shot holes shall notify the commission in writing that it intends to plug and abandon the drill hole. The required notice must be received by the commission at least twenty-four hours before the time plugging activities are scheduled to begin. The notice must include the date and time the activities are expected to commence, the location by section, township, and range of the holes to be plugged, and the name and telephone number of the person in charge of the plugging operations. A copy of the notice must be sent to the landowner or lessee at the same time it is sent to the commission. The seismic company shall notify the commission in writing upon completion of the plugging operation.
3. All seismic shot holes must be plugged as soon after being used as reasonably is practicable; however, they may not remain unplugged for a period of more than thirty days unless, upon

application, the commission grants an extension which may not exceed ninety days. All seismic shot holes must be temporarily capped during the period between drilling and final plugging.

4. The plug must have permanently affixed to it a durable nonrusting metal or plastic tag or plate imprinted with the name of the operator responsible for the plugging of the hole and the operator's permit number.
5. The surface around each seismic shot hole must be restored to its original condition insofar as restoration is practicable and all stakes, markers, cables, ropes, wires, primacord, cement or mud stacks, and any other debris or material not native to the area must be removed from the drill site and lawfully disposed of.

Source: N.D. Century Code.

38-08.1-06.1. PLUGGING REQUIREMENTS - RULES - LIABILITY FOR DAMAGE. All seismic holes must be plugged in accordance with rules adopted by the commission. The commission shall review and revise its rules governing plugging requirements as technology in the field evolves. The seismic company is liable for all damages resulting from failure to comply with rules adopted by the commission pursuant to this section.

Source: N.D. Century Code.

38-08.1-07. CIVIL AND CRIMINAL PENALTIES.

1. A person who violates any provision of this chapter or commission rule or order is subject to a civil penalty imposed by the commission not to exceed one thousand dollars for each offense, and each day's violation is a separate offense. A penalty imposed under this section, if not paid, may be recovered by the commission in the district court of the county in which the defendant resides, or in which any defendant resides if there is more than one defendant, or in the district court of any county in which the violation occurred. Payment of the penalty does not legalize the activity for which the penalty was imposed, or relieve the person upon whom the penalty was imposed from liability to any other person for damage caused by the violation.
2. Notwithstanding this section, a person who willfully violates any provision of this chapter or a commission rule or order is guilty of a class C felony.

Source: N.D. Century Code.

38-08.1-08. COMMISSION TO ADOPT RULES. The commission may adopt and enforce rules to implement this chapter.

Source: N.D. Century Code.

GEOPHYSICAL EXPLORATION REQUIREMENTS
CHAPTER 43-02-12

43-02-12-01. DEFINITIONS. The terms used in this chapter have the same meaning as in North Dakota Century Code chapter 38-08.1 except:

1. "Building" means any residence or commercial structure including a barn, stable, or other similar structure.
2. "Director" means the director of oil and gas of the industrial commission, the assistant director of oil and gas of the industrial commission, and their designated representatives.

History: Effective December 1, 1997; amended effective September 1, 2000; January 1, 2006.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-01

43-02-12-02. CERTIFICATION TO DO BUSINESS WITHIN STATE - RESIDENT AGENT.

Any person desiring to engage in geophysical exploration within this state, including a contractor and subcontractor, shall obtain from the secretary of state a certificate of authority to transact business in this state. A copy of this certificate must be filed with the commission prior to, or together with, the bond required herein and the application for permit to engage in geophysical exploration.

History: Effective December 1, 1997.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-03

43-02-12-03. BONDING REQUIREMENTS.

1. To satisfy the obligation that a geophysical exploration contractor desiring to engage in geophysical exploration shall file with the commission a good and sufficient surety bond, the contractor, in lieu of a surety bond, may post cash or a certificate of deposit with the Bank of North Dakota. Persons desiring to file a cash bond or certificate of deposit shall file with the commission an application to deposit cash or certificate of deposit. If the applicant is currently in compliance with the statutes, rules, and orders of the commission, the commission will issue to the Bank of North Dakota a compliance statement authorizing the Bank of North Dakota to accept cash or a certificate of deposit as a bond for the applicant.
2. Geophysical exploration contractors shall file with the commission a good and sufficient bond in the amount of fifty thousand dollars if the contractor intends to conduct shot hole operations or in the amount of twenty-five thousand dollars if the contractor intends to use any other method of geophysical exploration. Each subcontractor engaged by the geophysical exploration contractor for the drilling and plugging of seismic shot holes shall file with the commission a good and sufficient bond in the amount of ten thousand dollars.

History: Effective December 1, 1997.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-03.1

43-02-12-04. EXPLORATION PERMIT - APPLICATION.

1. Any person applying to the commission for an exploration permit must have a certificate to conduct geophysical exploration pursuant to subsection 3 of North Dakota Century Code section 38-08.1-03.1. A person may not commence geophysical exploration activities in this state without first obtaining an exploration permit from the commission. An application for an exploration permit must be submitted to the commission at least three business days before commencing operations and include the following:
 - a. The name, permanent address, and telephone number of the geophysical contractor and the geophysical contractor's local representative.
 - b. The name, permanent address, and telephone number of the drilling and hole plugging contractor, if different from the seismic contractor.
 - c. The name and address of the resident agent for service of process of the person intending to engage in geophysical exploration.
 - d. The bond number, type, and amount for the geophysical company.
 - e. The geophysical exploration method (i.e., shot hole, nonexplosive, 2D, or 3D).
 - f. The number, depth, and location of the seismic holes and the size of the explosive charges, if applicable.
 - g. The anticipated starting date of seismic and plugging operations.
 - h. The anticipated completion date of seismic and plugging operations.
 - i. A description of hole plugging procedures.
 - j. A description of the identifying marks that will be on the nonmetallic plug to be used in the plugging of the seismic hole.
 - k. A preplot map displaying the proposed seismic source points and receiver lines and specifically identifying all source points that do not comply with section 43-02-12-05.
 - l. A fee of one hundred dollars.
2. The permitholder shall notify the commission at least twenty-four hours, excluding Saturdays and holidays, before commencing geophysical activity.
3. The permitholder shall immediately notify the commission of any revisions to an approved seismic permit.

History: Effective December 1, 1997; amended effective September 1, 2000; May 1, 2004.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-04.1

43-02-12-05. DISTANCE RESTRICTIONS - SHOT HOLE OPERATIONS - NONEXPLOSIVE METHODS. Seismic shot hole operations may not be conducted less than six hundred sixty feet [201.17 meters] from water wells, buildings, underground cisterns, pipelines, and flowing springs.

Nonexplosive exploration methods may not be conducted less than three hundred feet [91.44 meters] from water wells, buildings, underground cisterns, pipelines, and flowing springs.

Variations may be granted to this section by written agreement between the permitholder and the owner of the subject property and must be available to the director upon request.

History: Effective December 1, 1997; amended effective September 1, 2000; May 1, 2004.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-08

43-02-12-06. NOTIFICATION OF WORK PERFORMED. Within thirty days following the completion of geophysical exploration by any person within this state, such person shall file with the commission a seismic completion report in the form of an affidavit deposing that the seismic project was completed in accordance with chapter 43-02-12, and incorporating a postplot map displaying the actual source point location and the location of all undetonated (loaded) holes, blowouts, and flowing holes or any other problem holes the director deems necessary. If obtained by the contractor, the latitude and longitude of each source and receiver point shall be submitted to the commission to the nearest tenth of a second.

Any person plugging a seismic hole must submit a plugging report and an affidavit of plugging detailing the line number, shot point number, hole depth, drill type, hole condition (wet, dry), bentonite used (sacks, capsules), and the depth at which the surface plug was set, and all other information necessary to describe the conditions of the shot hole.

History: Effective December 1, 1997; amended effective September 1, 2000; May 1, 2004.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-02,
38-08.1-05

43-02-12-07. DRILLING AND PLUGGING REQUIREMENTS.

1. Prior to commencement of any drilling or plugging operations, the director may require a field meeting with the geophysical contractor and subcontractors.
2. Except in those circumstances in which the director allows otherwise, all seismic shot holes must be plugged the same day as they were drilled and loaded. Any blown out shot holes must be plugged as soon as reasonably practicable, unless, upon application, the director grants an extension which may not exceed ninety days. All seismic shot holes must be temporarily capped until final plugging.
3. If the number of drilling rigs on a proposed project exceeds the director's capacity to provide appropriate inspection, the director may limit the number of drilling rigs.
4. Bentonite materials used in seismic hole plugging must be derived from naturally occurring untreated, high swelling sodium bentonite which consists principally of the mineral montmorillonite.
5. A durable nonmetallic plug must be set at a depth of approximately three feet [91.44 centimeters] below the surface of every shot hole. The plug must be designed to fit the hole and shall be imprinted with the mark of the operator responsible for the plugging, the mark of the permitholder, and the permitted project number.
6. Unless the contractor can prove to the satisfaction of the commission that another method will provide better protection to ground water and long-term land stability, seismic shot hole plugging shall be conducted in the following manner:

- a. When water is used in conjunction with the drilling of seismic shot holes or when water is encountered in the hole, the shot holes are to be filled with coarse ground bentonite approximately three-fourths of one inch [19.05 millimeters] in diameter from the top of the charge up to a depth above the final water level. Cuttings shall be added from the top of the bentonite to the surface. All cuttings added above the nonmetallic plug shall be tamped.
- b. When drilling with air only, and in completely dry holes, a plugging may be accomplished by returning the cuttings to the hole. A small mound must be left over the hole for settling allowance.
- c. Remaining cap leads must be cut off below ground level and any drilling fluid or cuttings which are deposited on the surface around the seismic hole will be spread out in such a manner that the growth of natural grasses or foliage will not be impaired.
- d. Any markings, including lath, pin flags, flagging, or any other debris left on the project area, including the powder magazine, must be removed and lawfully disposed of.

History: Effective December 1, 1997; amended effective September 1, 2000; May 1, 2004.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-02,
38-08.1-06,
38-08.1-06.1

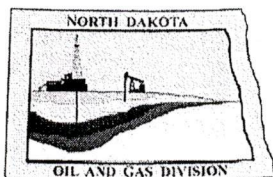
43-02-12-08. BOOKS AND RECORDS TO BE KEPT TO SUBSTANTIATE REPORTS. All geophysical, drilling, and plugging contractors shall make and keep appropriate books and records for a period of not less than six years, covering their operations in North Dakota from which they may be able to make and substantiate the reports required by this chapter.

History: Effective September 1, 2000.

General Authority
NDCC 38-08.1

Law Implemented
NDCC 38-08.1-08

APPENDIX B



Oil and Gas Division

Lynn D. Helms - Director Bruce E. Hicks - Assistant Director

Department of Mineral Resources

Lynn D. Helms - Director

North Dakota Industrial Commission

www.oilgas.nd.gov

NOTICE TO SURFACE OWNERS CONCERNING THE RIGHT OF COMPENSATION FOR DAMAGES CAUSED BY OIL AND GAS OPERATIONS

This letter is furnished to advise you of your rights and options as a surface owner or tenant under North Dakota law. This form as well as information disclosing the plan of operations contemplated by the mineral developer are intended to assist you in evaluating the effect such activity will have on the use of your property. You are responsible for negotiating the terms of any agreements. If you need advice or assistance in making a settlement, you should consult private counsel.

North Dakota Century Code Reference

North Dakota Century Code (NDCC) Chapter 38-11.1 provides that all persons should be justly compensated for personal injury, property damage, and interference with the use of their property caused by oil and gas development.

Oil and gas development means the drilling, completion, production, or other operations of an oil and gas well which require entry upon the surface estate.

The law provides that surface owners and their tenants are entitled to compensation from the mineral developer for: 1) loss of agricultural production and income, 2) lost land value, 3) lost use and access, or 4) lost value of improvements caused by oil and gas drilling operations that directly affect the land where said operations occur.

Notice Requirements

Except for geophysical exploration activities, which are governed by NDCC Chapter 38-08.1, you are entitled to written notice of any contemplated drilling operations at least twenty (20) days prior to the start of the operations unless notice requirements are waived by mutual agreement of both parties. If the mineral developer plans to begin drilling operations within twenty (20) days of the termination date of the mineral lease, the required notice may be given at any time prior to the start of drilling operations. This notice must be given to you as the record surface owner, at your address as shown by the records of the appropriate county register of deeds at the time the notice is given. This notice must sufficiently disclose the plan of work and operations so you are able to evaluate the effect of drilling operations on the use of your property. If a mineral developer fails to give notice as provided above, you may file a court action and may receive punitive as well as actual damages.

Hydrogen Sulfide

You, or an adjacent landowner, may request the state department of health to inspect and monitor the well site on your land for the presence of hydrogen sulfide. If the presence of hydrogen sulfide is indicated the state department of health will issue appropriate orders to protect your health, welfare, and property.

Settlement Negotiations

The mineral developer must make a written offer of settlement at the time the notice of contemplated drilling operations is given, unless both you and the mineral developer have agreed otherwise in writing. You may accept

or reject any offer so made. Final agreement on the amount of compensation for damages does not have to be reached before the mineral developer begins drilling operations, and may be best negotiated after it is determined whether the well is commercial. If you reject the offers of the mineral developer you may bring a court action seeking proper compensation. If the amount of compensation awarded by the court is greater than that offered by the mineral developer you will be awarded reasonable attorney fees, court costs, and interest on the amount of compensation from the day drilling is commenced.

The amount of compensation for damages may be determined by any formula mutually agreeable between the surface owner and the mineral developer. Compensation for damages caused by drilling operations must be calculated as a single sum. When determining damages you must consider the period of time during which the loss will occur and you may elect to be paid the damages in annual installments over that period of time.

Any reservation or assignment of payment to someone other than the surface owner or tenant is prohibited. In the absence of an agreement between the surface owner and a tenant as to the division of compensation, the tenant is entitled to recover from the surface owner that portion of the payments attributable to the tenant's share of the damages.

Nuisance or Lack of Ordinary Care Claims

Other parts of NDCC 38-11.1 provide that the mineral developer is responsible for all damages to any person (not just a surface owner) or property resulting from the lack of ordinary care by the mineral developer or from a nuisance caused by drilling operations. Any person seeking compensation must notify the mineral developer within two (2) years after the injury occurs or would be apparent to a reasonable person.

Underground Water Supplies

NDCC Chapter 38-11.1 further provides protection of your surface or underground water supplies for domestic, livestock, irrigation, agricultural, industrial, or other beneficial use. If you own an interest in real property and obtain all or part of your water supply for any beneficial use from an underground source, you may have a claim against a mineral developer for disruption or diminution in water quality or quantity proximately caused by drilling operations. This law does not apply if water can reasonably be acquired under the changed conditions and the changed conditions are the result of the legal appropriation of water by the mineral developer.

You may have a claim for damages against the mineral developer provided that:

- 1) The water supply is disrupted or diminished in quality or quantity on real property you own within one-half (1/2) mile of where geophysical exploration activities are, or have been conducted, or within one (1) mile of an oil and gas well site, and
- 2) A certified water quality and quantity test has been performed within one (1) year preceding the start of drilling operations, and
- 3) A claim for damages is filed within six (6) years from the time damage was discovered or should have been reasonably discovered.

No tract of land is obligated to receive water contaminated by drilling operations on another tract of land. The owner has a claim against the mineral developer to recover damages resulting from natural drainage of such waters onto a tract of land.

Other Remedies and Limitations

The remedies provided by this law do not prohibit you from seeking other legal remedies.

This law does not apply to damages resulting from the operation, maintenance, or use of a motor vehicle upon a highway.

Dated this 3rd day of July, 2003.

/s/ Lynn D. Helms

Lynn D. Helms
Director

APPENDIX C

43-02-03-18. DRILLING UNITS - WELL LOCATIONS. In the absence of an order by the commission setting spacing units for a pool:

1. a. Vertical or directional oil wells projected to a depth not deeper than the Mission Canyon formation shall be drilled upon a governmental quarter-quarter section or equivalent lot, located not less than five hundred feet [152.4 meters] to the boundary of such governmental quarter-quarter section or equivalent lot. No more than one well shall be drilled to the same pool on any such governmental quarter-quarter section or equivalent lot, except by order of the commission, nor shall any well be drilled on any such governmental quarter-quarter section or equivalent lot containing less than thirty-six acres [14.57 hectares] except by order of the commission.
- b. Vertical or directional oil wells projected to a depth deeper than the Mission Canyon formation shall be drilled on a governmental quarter section or equivalent lots, located not less than six hundred sixty feet [201.17 meters] to the boundary of such governmental quarter section or equivalent lots. No more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission, nor shall any well be drilled on any such governmental quarter section or equivalent lots containing less than one hundred forty-five acres [58.68 hectares] except by order of the commission.
2. Horizontal wells with a horizontal displacement of the well bore drilled at an angle of at least eighty degrees within the productive formation of at least five hundred feet [152.4 meters], must be drilled upon a drilling unit described as a governmental section or described as two adjacent governmental quarter sections within the same section or equivalent lots, located not less than five hundred feet [152.4 meters] to the outside boundary of such tract. The horizontal well proposed to be drilled must, in the director's opinion, justify the creation of such drilling unit. No more than one well may be drilled to the same pool on any such tract, except by order of the commission.
3. a. Gas wells projected to a depth not deeper than the Mission Canyon formation shall be drilled upon a governmental quarter section or equivalent lots, located not less than five hundred feet [152.4 meters] to the boundary of such governmental quarter section or equivalent lots. No more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission, nor shall any well be drilled on any such governmental quarter section or equivalent lot containing less than one hundred forty-five acres [14.57 hectares] except by order of the commission.
- b. Gas wells projected to a depth deeper than the Mission Canyon formation shall be drilled upon a governmental quarter section or equivalent lots, located not less than six hundred sixty feet [201.17 meters] to the boundary of such governmental quarter section or equivalent lots. No more than one well shall be drilled to the same pool on any such governmental quarter section or equivalent lots, except by order of the commission, nor shall any well be drilled on any such governmental quarter section or equivalent lot containing less than one hundred forty-five acres [14.57 hectares] except by order of the commission.
4. Within thirty days, or a reasonable time thereafter, following the discovery of oil or gas in a pool not then covered by an order of the commission, a spacing hearing shall be docketed. Following such hearing the commission shall issue an order prescribing a temporary spacing pattern for the development of the pool. This order shall continue in force for a period of not

more than eighteen months at the expiration of which time a hearing shall be held at which the commission may require the presentation of such evidence as will enable the commission to determine the proper spacing for the pool.

During the interim period between the discovery and the issuance of the temporary order, no permits shall be issued for the drilling of an offset well to the discovery well, unless approved by the director. Approval shall be consistent with anticipated spacing for the orderly development of the pool.

Any well drilled within one mile [1.61 kilometers] of an established field shall conform to the spacing requirements in that field except when it is apparent that the well will not produce from the same common source of supply. In order to assure uniform and orderly development, any well drilled within one mile [1.61 kilometers] of an established field boundary shall conform to the spacing and special field rules for the field, and for the purposes of spacing and pooling, the field boundary shall be extended to include the spacing unit for such well and any intervening lands. The foregoing shall not be applicable if it is apparent that the well will not produce from the same common source of supply as wells within the field.

5. If the director denies an application for permit, the director shall advise the applicant immediately of the reasons for denial. The decision of the director may be appealed to the commission.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; May 1, 1994; July 1, 1996; July 1, 2002; January 1, 2006.

General Authority
NDCC 38-08-04
38-08-07

Law Implemented
NDCC 38-08-04
38-08-07

North Dakota State University grants the N. D. Department of Mineral Resources, Oil and Gas Division, permission to adapt the November 1981 NDSU Extension Service publication "North Dakota Oil and Gas Leasing Considerations" for educational, non-commercial purposes.

**STATE OF MINNESOTA
ENVIRONMENTAL QUALITY BOARD**

In the Matter of the Application of the Minnesota Soybean Processors (MnSP) for a Pipeline Routing Permit and Partial Exemption from Pipeline Route Selection Procedures Pursuant to Minnesota Rules Chapter 4415

**FINDINGS OF FACT,
CONCLUSIONS, AND ORDER**

**MEQB DOCKET NO.
03-62-PRP-MnSP**

The above-captioned matter came before the Minnesota Environmental Quality Board (EQB) at a regularly scheduled meeting pursuant to the Application of the Minnesota Soybean Processors (hereinafter "MnSP") to construct, own, and operate a 6.4 mile natural gas pipeline from an interconnection with Northern Natural Pipeline Company (NNPL) near Brewster, MN to a MnSP processing plant under construction near Brewster, MN. The proposed pipeline will traverse portions of Jackson and Nobles Counties in southwestern Minnesota.

STATEMENT OF ISSUE

Construction of a pipeline designed to be operated at a pressure of more than 275 pounds per square inch and to carry natural gas requires a Pipeline Routing Permit from the Minnesota Environmental Quality Board. Minnesota Statutes § 116I.015 prescribes applicable requirements and assigns authority to designate a route to the EQB. The review procedures are contained in Minnesota Rules Chapter 4415. In this instance, review is taking place under the requirements set forth in Minnesota Rules part 4415.0035 [Partial Exemption from Pipeline Route Selection Procedures].

Based on information in the Application, the comments at the public information meeting, written comments received, and other documents compiled as part of this proceeding relating to pipeline construction impacts and mitigation procedures, the EQB makes the following Findings of Fact.

FINDINGS OF FACT

Background and Procedure

1. In April, 2003, Minnesota Soybean Processors filed a preliminary Application for a pipeline routing permit and partial exemption from pipeline route selection procedures for a proposed 6.4 mile long natural gas pipeline from an interconnection with Northern Natural Pipeline Company (NNPL) near Brewster, MN to a MnSP processing plant under construction near Brewster, MN. The pipeline will cross portions of Jackson and Nobles counties (Exhibit 1).
2. EQB staff reviewed the preliminary application for compliance with the requirements of Minnesota Rules parts 4415.0115 through 4415.0165, and requested supplemental

information. MnSP revised their application and in May, 2003 resubmitted their application. EQB staff review concluded that the revised application contained all of the necessary information (Exhibit 2) and recommended that the EQB Chair accept the application. On May 22, 2003, the EQB Chair accepted the MnSP Application for a pipeline routing permit and partial exemption from pipeline route selection procedures. The Chair notified MnSP of his decision to accept the Application in a letter dated May 23, 2003 (Exhibit 3). The EQB staff notified EQB members and technical representatives of the Chair's decision to accept the Application in a memorandum dated May, 22, 2002 (Exhibit 4).

3. After acceptance of the application by the Chair, the MnSP published notice of the acceptance in area newspapers (Exhibit 5). The notice announced the EQB's public information meeting schedule, the date by which comments were due, and how to obtain additional project information and other project related material. The MnSP notice was published the week of May 25, 2003, in the following newspapers:

Newspaper	County	Date Published
<i>Worthington Daily Globe</i>	Nobles	May 28, 2003
<i>Lakefield Standard</i>	Jackson	May 29, 2003

4. The notice as published also included: 1) a description of the proposed project; 2) a map of the proposed pipeline route; and 3) a description of the procedures that must be followed for commenting on the application (Exhibit 5). The notice contained the information required by Minnesota Rules part 4415.0035, Subp. 2. A.
5. The EQB also published Notice of Application Acceptance and the EQB public information schedule in the *EQB Monitor* on May 26, 2003. *Monitor*, Volume 27, Number 11. (Exhibit 6).
6. On May 27, 2003, MnSP mailed a copy of the Application and a description of the procedures for commenting on the Application to affected landowners and governmental units in the areas that would be crossed by the pipeline along the MnSP preferred route in accordance with Minnesota Rules parts 4415.0035, subp. 2. B. and C (Exhibit 7). The mailing also advised the recipient of the EQB's public information meeting.
7. The EQB held a public information meeting, as required by Minnesota Rules part 4415.0035 subp. 4. The EQB public information meeting was held in Brewster, MN on June 9, 2003, at the American Legion Hall.

The Applicant

8. Minnesota Soybean Processors is headquartered in Volga, South Dakota, and is the project proposer. MnSP has retained Great Plains Natural Gas Company as its agent to design, build and operate the proposed pipeline. Therefore, the EQB permit will identify MnSP and GPNG as the permittees for the proposed project.

The Project

9. The proposed 6.4 mile natural gas pipeline will have an outside diameter of 4.5 inches and begin at a tap on the Northern Natural Pipeline in the northwest $\frac{1}{4}$ of Section 30 in Ewington Township in Jackson County and will proceed west 600 feet and then proceed northward through Lorain and Hersey Townships, and then terminate at the Minnesota Soybean Processors plant under construction in the southeast $\frac{1}{4}$ of Section 24 in Hersey Township just north of Brewster in Nobles County.
10. The estimated total cost of the pipeline is approximately \$1.1 million.
11. The normal operating pressure of the pipeline and associated facilities will be between 400 pounds per square inch gauge and 720 psig. The proposed natural gas pipeline and associated facilities are designed to have a maximum throughput capacity of 5,000 Mcf per day (thousand cubic feet per day). The minimum throughput design is 2,400 Mcf per day.

Facility Description

12. The facilities proposed by MnSP specify 4.5-inch (outside diameter) steel pipe and related materials that include valves, flanges, pipe fittings, coating and wrapping materials, casing, pipe supports, caution signs for crossings and other miscellaneous materials.
13. The 4.5-inch pipe will have a nominal pipe wall thickness of 0.156 inches. When the pipe crosses roads and streams, the pipe wall thickness will be 0.237 inches. The type of pipe used will be American Petroleum Institute 5L, X52, ERW. ERW has one longitudinal seam, which is formed by electric resistance welding during the manufacturing process. The maximum allowable operating pressure of the proposed pipeline is 720 pounds per square inch.
14. In addition to the steel pipe, this project will have above ground valves at the beginning and end of the pipeline along with associated launching and receiving scraper traps. At the interconnection point with Northern Natural, there will be regulation and measurement facilities above ground. MnSP will install marker posts along the route to identify the location of the buried facilities. Typically, these are installed at property boundaries and/or roads to minimize interference with land utilization. At approximately one mile intervals and adjacent to the marker posts, MnSP will install electrolysis test stations to monitor the effectiveness of cathodic protection efforts.
15. Cathodic protection will be provided on the pipeline to stop galvanic corrosion and will comply with all requirements of the U.S. Department of Transportation Pipeline Safety Regulations, 49 CFR Part 192. As part of the cathodic protection system, rectifiers and anode ground beds will be located along side the right-of-way.

Land Requirements

16. MnSP proposes to obtain from landowners permanent right-of-way thirty (30) feet in width. Based on a pipeline of 6.4 miles in length along the MnSP preferred route, approximately 22 acres of new right-of-way will be acquired.
17. MnSP also proposes to obtain from landowners an additional twenty (20) feet of temporary workspace. It is anticipated that this space will not be fully utilized, but will give the construction crews approximately 50 feet of right-of-way for workspace if needed. Approximately 15 acres of temporary workspace will be acquired. Temporary right-of-way or workspace will revert to landowners upon completion of construction. Additional temporary workspace adjacent to the construction right-of-way may be necessary during construction in areas such as steep slopes and staging areas for stream, wetland, and road crossings, for safety reasons, to provide an area for prefabrication of sections of pipeline, or storage of spoil materials. MnSP will acquire additional workspace from the landowner where necessary; however in all cases, the size of extra workspace will be kept to the minimum required to safely conduct the work.

Trench and Depth of Cover Requirements

18. Minnesota Statutes § 116I.06, subd. 1 requires pipelines to be buried with a minimum level cover of not less than 54 inches, in all areas where the pipeline crosses the right-of-way of any public drainage facility or any county, town or municipal street or highway and where the pipeline crosses cultivated agricultural land. As provided by Minnesota Statutes § 116I.06, subd. 2, the landowner may waive the depth of cover requirements. Any political subdivision authorized by law to approve the use of the right-of-way of any public drainage facility or any public street or highway for a pipeline may waive the minimum depth of cover requirement or adopt and enforce by resolution or ordinance rules or regulations establishing a greater depth than the minimum required and other measures for protection of public roads and drainage facilities under its jurisdiction. MnSP has committed to burying the pipeline 54 inches deep or more in accordance with state requirements.
19. The trench in which the pipe is placed will have a minimum depth of 60 inches to allow for a minimum of 54 inches of ground cover to the top of the pipe. The pipe will be placed below drain tiles. The trench will have a minimum width of 12 inches for the 4.5-inch pipe. The top and bottom widths are determined by soil conditions. In sandy soils, a wider trench will be necessary for sidewall stability. The trench required for the proposed pipeline will result in a minimum excavation volume of 5,900 cubic yards of soil.

Pipeline Safety

20. Pipeline safety is a matter of paramount concern to all interested parties. MnSP, as noted in its Application and in these findings, is subject to the U.S. Department of Transportation, Pipeline Safety Regulations (Title 49, C.F.R., Part 192).

21. The Minnesota Office of Pipeline Safety is responsible for enforcement of the pipeline safety regulations. The Office of Pipeline Safety intends to monitor construction of the proposed pipeline for compliance with the regulations. The Office of Pipeline Safety also has an ongoing responsibility for monitoring MnSP pipeline facilities for compliance with the safety regulations.

EQB Public Information Meeting

22. The EQB held one public information meeting in Brewster in Nobles County to receive public comment on the MnSP application as noted in Finding 7. Approximately twenty persons attended the EQB public information meeting. EQB staff presented an overview of the requirements for a pipeline routing permit and for a partial exemption from pipeline route selection procedures. MnSP provided an overview of the project. MnSP also had their pipeline contractor and drain tile repair contractor there to respond to questions.
23. EQB staff, MnSP and GPNG representatives were available for questions. No comments were offered and there were no questions from affected landowners or other interested persons.

Comment Letters

24. The EQB staff announced at the public meeting that the EQB would accept public comments about the proposed project and the Application for a partial exemption and routing permit until June 25, 2003. Three (3) comment letters were received on the MnSP proposed pipeline by the end of this period. The comment letters came from the Department of Natural Resources, the Minnesota Pollution Control Agency and the Southwest Regional Development Commission (Exhibits 8 through 10).
25. No issues were raised or identified in the comment letters. MnSP is subject to the terms and conditions of any DNR and MPCA license and permit requirements, as well as any Jackson or Nobles County permit requirements.

Alternatives to the Proposed Pipeline Route

26. MnSP also looked at an alternative route along the west side of TH 264 and Nobles County Road 1, but encountered an existing fiber-optics line in the road right-of-way. Landowners specifically requested that the pipeline be placed along the preferred alignment to minimize impacts to farmsteads along the route.

Standard for Partial Exemption From Pipeline Route Selection Procedures [Minnesota Rules, Part 4415.0040]

27. In determining whether to grant or deny a partial exemption from pipeline route selection procedures, the EQB must apply the requirements of Minnesota Rules part 4415.0040 [Criteria for Partial Exemption from Pipeline Route Selection Procedures]. This part

contains the standard and criteria that the Board must apply in determining whether to grant or deny the partial exemption

28. Minnesota Rules part 4415.0040, subp. 2, [Standard], requires the Board to determine that the proposed pipeline will not have a significant impact on humans or the environment in order to grant the partial exemption. In conducting this evaluation, the Board must consider a number of criteria set forth in subpart 3 of the rule.
29. The major difference between the partial exemption process and the full routing process is that under the full routing process a more comprehensive evaluation of alternatives is conducted and a contested case hearing presided over by an administrative law judge is required. Both processes require the publication of notice in local newspapers announcing the holding of public meetings at an early stage of the process. Both processes result in the designation of a route and the imposition of conditions to minimize human and environmental impacts from the pipeline.

Standard for Pipeline Route Selection [Minnesota Rules, Part 4415.0100]

30. Minn. Rules part 4415.0100, subp. 2 [Standard] provides that the Board shall consider the characteristics, the potential impacts, and mitigation measures associated with the proposed pipeline so that the Board may designate a route that minimizes human and environmental impacts. Regardless of the procedures followed, the Board attempts to minimize the impacts from any new pipeline.
31. In designating a route, subpart 3 requires the Board to take into account the same criteria set forth in part 4415.0040, subp. 3 for determining the appropriateness of a partial exemption from pipeline route selection procedures.
32. "Route" has been defined by the EQB in Minn. Rules part 4415.0010, subp. 32, to include "a variable width from the minimum required for the pipeline right-of-way up to 1.25 miles." In other pipeline routing permits issued by the Board, the Board has more specifically limited the width of the route when an existing right-of-way is being used. In this instance MnSP and the landowners have agreed to a specific location for the proposed right-of-way. Therefore it is reasonable for the EQB to limit the route width to something much less than 1.25 miles in which the right-of-way will be located. A route width of 500 feet or 250 feet on either side of the centerline of the proposed right-of-way is appropriate.
33. Pipeline routing permits are subject to reasonable conditions imposed by the EQB. Conditions are intended to protect the environment and landowners from adverse effects from construction of the pipeline.

Consideration of Pipeline Routing Criteria

34. In determining whether to grant a partial exemption request and designate a route, the EQB considers the criteria set forth in the rules. The following findings discuss the specific impacts on humans and the environment of a pipeline between the Northern Natural Pipeline and the MnSP facilities being built east and north of Brewster.

35. For nearly the entire distance of the pipeline, the major impact of concern is the impact on agricultural land and farming operations. Regardless of right-of-way or centerline location, certain mitigation procedures and construction practices will be followed pursuant to pipeline routing permit conditions.

Criterion A. Impact on human settlement, existence and density of populated areas, existing and planned future land use, and management plans.

36. The pipeline will be installed in rural areas of Jackson and Nobles counties in southwestern Minnesota. The pipeline does not cross any incorporated areas, except for the City of Brewster. The area along the route is sparsely populated and is used almost exclusively for agricultural purposes.
37. The proposed route will cross approximately 14 parcels of property along its entire length.
38. Future development is more likely to occur along or adjacent to TH 264 and Nobles County Highway 1, than 600 feet away from these existing road rights-of-ways. If the pipeline were inside the road right-of-way, the pipeline may need to be relocated if the roadway were widened or otherwise modified in the future. Additionally, the possibility of damage to the line from careless excavations and other activity along the road right-of-way would be greater.
39. Future development along the pipeline right-of-way is regulated by ordinance setbacks established pursuant to the requirements of Minnesota Statutes § 299J.05 [Pipeline Setback Ordinance]. This ordinance requires that no development occur within the permanent right-of-way. The proposed pipeline alignment is not in conflict with any existing or planned residential, commercial or industrial development in the area.
40. The MnSP right-of-way alignment will not significantly affect human settlement areas, planned future land uses, or any local management plans.

Criterion B. Impact on the natural environment, public and designated lands, including but not limited to natural areas, wildlife habitat, water, and recreational lands.

41. Two stream crossings have been identified along the alignment of the proposed pipeline. The pipeline will cross Okabena Creek and Elk Creek. The proposed method of crossing these water bodies will be by directional drilling so as to minimize any impact to these water bodies. Permits to cross these water bodies will be obtained from the MN Department of Natural Resources, and the crossing methods will be dictated by the permit conditions.
42. MnSP proposes to cross Okabena Creek and Elk Creek using the directional drill technique. Any inadvertent releases of drilling fluids would be contained by hay bales or other appropriate materials. Vacuum or sump pumps would then be used to clean up and transfer the drilling fluids back to the entry or exit points of the drilling mud pits for either reprocessing or disposal. If the directional drill cannot be completed, the borehole

would be sealed by mixing a commercially available grout additive into the drilling fluid as the drill pipe is withdrawn.

43. No compression facilities are to be installed on the proposed pipeline so there will not be any exhaust or other noise from these facilities. The pipeline does not generate any noise under normal operations. During construction, the machinery generates noise between 75-90 decibels within 50 feet of the equipment. The noise is typical of the machinery that is used in tilling, harvesting and other agriculture operations. Equipment noise impact would be short-term as the construction process moves continuously along the right-of-way.
44. A hydrostatic test of the pipeline is required prior to its being placed in service. MnSP estimates that it will have to withdraw approximately 24,000 gallons from local water supplies. During the testing, MnSP will screen water intakes to prevent entrapment of fish and debris and will neither withdraw nor discharge water during critical fish spawning periods. No chemicals will be added to the hydrostatic test water. The water will be tested during withdrawal, after the pipeline is filled, and during discharge. The hydrostatic test water will be discharged into a holding tank with a progressive weir arrangement to trap rust, mill scale or other undesirable items. The discharge rate would be regulated and splash plates or other similar devices installed to disperse the discharge in order to prevent erosion, stream scour, suspension of sediments, or excessive stream flow. An appropriation permit for the hydrostatic test water will be obtained from the Minnesota DNR and a discharge permit from the Minnesota Pollution Control Agency is required to return the water to its source. Impacts from this testing should be minimal and short term.

Criterion C. Impact on lands of historical, archaeological and cultural significance.

45. The Minnesota Historical Society/State Historic Preservation Office (SHPO) was contacted to review the route pursuant to the Minnesota Historical Sites Act and the Field Archaeology Act. This part of Minnesota is intensively farmed and tilled. These agricultural practices over many years damaged or destroyed many of the existing archaeological resources. While no impacts on such resources are anticipated, the pipeline routing permit addresses preservation of archeological sites should any be discovered during construction.

Criterion D. Impact on economies within the route, including agricultural, commercial or industrial, forestry, recreational and mining operations.

46. Agricultural cropland accounts for approximately 95 percent of the land that the pipeline will cross. The majority of the cropland is planted in corn or soybeans.
47. Approximately 37 acres of agricultural land will be temporarily disturbed during construction of the pipeline following MnSP route.
48. Construction activities will temporarily utilize active cropland within construction work areas. Construction activities may also interfere with planting or harvesting, depending on the construction season. After construction is completed, agricultural activities will be

allowed to resume in the pipeline right-of-way. Landowners will be compensated for crop losses and other damages caused by construction activities.

49. MnSP will be responsible for the repair of all drain tiles that are damaged as a result of pipeline construction.
50. To minimize soil compaction, chisel plowing, disk harrowing, right-of-way stripping, or other appropriate techniques will be implemented.
51. MnSP will implement double ditching as a means to minimize mixing of topsoil and subsoil during excavation of the trench for the pipe. Double ditching is a technique whereby the topsoil and the sub soils are placed in separate areas. Double ditching is a requirement in the pipeline routing permit. Other techniques can be investigated with the landowner at the time construction is to take place.
52. Under some wet weather conditions, construction will have to be temporarily delayed until weather permits.
53. Pipeline routing permit conditions and construction specifications specifically address soil compaction, erosion control and right-of-way restoration. In addition, the MnSP has been meeting with local landowners to discuss any particular concerns they may have. MnSP will implement an agricultural impact mitigation plan establishing reasonable construction practices and mitigation measures to minimize the impact of the pipeline on agricultural lands and landowners. Condition VII. A., of the pipeline routing permit requires compliance with the "Agricultural Impact Mitigation Plan" developed for this project.
54. Great Plains Natural Gas Company will build and operate the pipeline and will be a co-permittee on the permit. Great Plains will be the primary permittee responsible for compliance with the Agricultural Impact Mitigation Plan.
55. During construction of the pipeline, workers from pipeline contractors, local laborers, equipment contractors, suppliers and regional testing firms will be involved with the project. In addition, construction inspectors as well as county inspectors will be employed during the project. During the period of right-of-way preparation, construction, testing and restoration, these workers will contribute to the local economy.
56. No industrial sites are located along the route.

Criterion E. Impact on pipeline cost and accessibility.

57. MnSP has estimated that the pipeline will cost approximately \$1.1 million to construct on the proposed route.
58. The location of the proposed pipeline will not limit accessibility during the construction phase.

Criterion F. Impact on use of existing rights-of-way and right-of-way sharing or paralleling.

59. Construction of the pipeline will generally require a 50-foot-wide construction right-of-way to allow for temporary storage of topsoil and spoil to accommodate safe operation of construction equipment. During construction, MnSP will acquire nearby temporary storage areas for pipe, materials, construction staging, equipment storage, and parking. At this time those areas have not been identified. Use of temporary storage areas outside the right-of-way is not regulated by this permit.
60. Additional temporary work space adjacent to the construction right-of-way may be necessary during construction in areas such as steep slopes and staging areas for stream, wetland and road crossing, for safety reasons, to provide an area for prefabrication of sections of pipeline or storage of spoil material. In all cases, the size of extra work space will be kept to the minimum required to safely conduct work. Temporary right-of-way will revert to landowners upon completion of construction.
61. Typically, public roads will be used to gain access to the construction right-of-way. In areas where public roads are limited, and to minimize repeated travel on portions of the right-of-way, existing privately owned roads might be used to provide access to the construction right-of-way. Use of private access roads and construction of any new access roads would require obtaining landowner permission prior to use. No private or new access roads have been identified at this time.
62. Traffic flows will temporarily increase during the construction period due to materials, equipment and laborer movements where roadways are crossed. MnSP will implement measures to minimize disruption to traffic and to protect the public. Access to the right-of-way will be properly coordinated with county and city officials and affected property owners.
63. Damage to surfaced roadways resulting from the crossing of construction equipment will be minimized by the use of protective planking or other appropriate material. Any road damages will be repaired to the satisfaction of the landowner or appropriate permitting authority.

Criterion G. Impact on natural resources and features.

64. The impacts of the pipeline on water crossings will be minimized as the water crossings will be either bored or constructed in compliance with MDNR requirements for crossing public lands and waters. The MnSP restoration plan and other permit requirements will minimize impacts.
65. At ditch crossings, grasses and other vegetation will be removed, but reseeded of any disrupted areas along banks is part of the MnSP restoration plan.
66. Wildlife species will be temporarily disrupted and may relocate to adjacent areas and reroute their travel in the area during construction of the pipeline.

67. Immediately following construction, disturbed areas will be restored to original contours and reseeded. Once vegetation is reestablished, there should be no further disturbance.
68. Where clearing is required on the right-of-way, soil from tree or shrub roots will be retained on the right-of-way. Rock, roots and stumps that are uprooted will be properly disposed of.
69. Exposed soils are also subject to wind and water erosion. However, the potential for erosion is not excessive due to the low relief of the area crossed and the fact that the trench will be open only for a relatively short time. MnSP will specify the special placement of berms or other specific erosion control measures and practices in areas where the potential for erosion exists.

Criterion H. The extent to which human or environmental effects are subject to mitigation by regulatory control and by application of the permit conditions contained in part 4415.0185 for pipeline right-of-way preparation, construction, cleanup and restoration practices.

70. Human and environmental impacts will occur as a result of pipeline construction. Many of the impacts associated with pipeline construction will cause only a temporary disturbance or disruption. Many of the impacts will be mitigated through compliance with regulatory control, strict adherence to the construction specifications, compliance with the pipeline routing permit condition, and compliance with the agricultural impact mitigation agreement developed for the MnSP pipeline project. Permits from other federal and state agencies and units of government are also designed to reduce or mitigate the impact of pipeline construction.
71. Following completion of construction operations, the right-of-way and all premises on which construction activities were conducted will be cleaned up. This will include removal of debris, fence repair, removal of temporary road and ditch crossings, additional grading to correct for soil settling and seeding of the right-of-way as required by EQB permit conditions and other federal and state agency permits.

Criterion I. Impact on cumulative potential effects of related or anticipated future pipeline construction.

72. There is no evidence in the record to indicate that cumulative adverse effects will occur that cannot be mitigated by compliance with appropriate permitting requirements and conditions. Compliance with applicable permits, regulations and agreements and strict adherence to the construction specifications will reduce the adverse effects of the project.
73. The capacity of the proposed pipeline is believed to be adequate to serve the foreseeable future needs of the MnSP plant in Brewster, MN. Any future project expansion will require review pursuant to the applicable statutes and rules.

Criterion J. Impact on relevant policies, rules, and regulations of the state and federal agencies and local government land use laws including ordinances adopted under Minnesota Statutes, section 299J.05, relating to the location, design, construction, or operation of the proposed pipeline and associated facilities.

74. There is no evidence in the record indicating that the proposed pipeline would be inconsistent with any relevant policies, rules and regulations of any known state or federal agencies or local land use laws.
75. MnSP provided in the Application a list of the known permits that must be obtained.
76. All appropriate permits will be acquired prior to undertaking the activity for which a permit is required. MnSP must comply with the terms and conditions of all necessary permits.
77. Minnesota Rules part 4415.0200 and the pipeline routing permit provide a procedure to report complaints concerning violation of the pipeline routing rule requirements and pipeline routing permit conditions.
78. Minnesota Rules part 4415.0205 provides procedures for permit modification or suspension for violation of the terms and conditions of a pipeline routing permit or of Minnesota Rules parts 4415.0010 to 4415.0215.

Based on the foregoing Findings of Fact, the Board makes the following:

CONCLUSIONS

1. The Minnesota Environmental Quality Board has fulfilled all relevant procedural requirements of law or rule applicable to the consideration of an application for a partial exemption from pipeline route selection procedures, and has the authority to grant a partial exemption from pipeline route selection procedures and to issue a pipeline routing permit.
2. Minnesota Soybean Processors has complied with the procedural requirements for a partial exemption from pipeline route selection procedures as set forth in Minnesota Rules part 4415.0035, including publication of notice in two local newspapers in the counties where the pipeline will be located.
3. The EQB has established in Minnesota Rules part 4415.0040 a standard and criteria for a partial exemption from pipeline route selection procedures. The Board has considered the potential impacts of the proposed natural gas pipeline in each of the areas specified in the rule, including the natural environment and human settlement. The Board concludes that with implementation of proper construction practices and mitigation measures, and compliance with appropriate permit conditions, and negotiation of specific accommodations with individual landowners, such a pipeline will not have a significant impact on humans or the environment and that a partial exemption from full routing procedures can be granted.

4. The MnSP proposed route crosses agricultural land along nearly its entire length. The primary impact of concern is the impact of the pipeline on farming operations, particularly damage to drain tile and compaction of soil. EQB designation of a route that meets with the satisfaction of landowners whose property will be crossed and construction methods that address landowners' concerns will allow this pipeline to be constructed in the most expeditious and economic manner.
5. Based on its consideration of the criteria for granting a routing permit for a new natural gas pipeline, the Board concludes that a permit for construction of a natural gas pipeline of approximately 6.4 miles along the following route will minimize human and environmental impacts:

The proposed 6.4-mile natural gas pipeline will begin at a tap on the Northern Natural Pipeline in the northwest $\frac{1}{4}$ of Section 30 in Ewington Township in Jackson County approximately 133 feet east of the section line (the centerline of TH-264) and 503 feet south of the north section line (Jackson County Road Number 34). The pipeline then runs north approximately 573 feet to a point approximately 70 feet north of the centerline of Jackson County Road Number 34. Then, it turns west to a point about 600 feet west of Trunk Highway 264 (the road dividing Nobles and Jackson County south of I-90). From this point, the line will continue northward, approximately 600 feet west of TH 264 (south of I 90) and Nobles County Road 1 (north of I 90) to a point where Sections 36 and 25 and Nobles County Road 1 intersect in Hersey Township. At this point the pipeline will shift to the east approximately 100 feet, and then continue north through the east side of Section 25 approximately 500 feet west of the County line. The proposed pipeline will terminate at the Minnesota Soybean Processors plant under construction in the southeast $\frac{1}{4}$ of Section 24 in Hersey Township just north of Brewster.

6. The Board concludes that it makes sense to limit the maximum width of the route to no more than 500 feet, or 250 feet on either side of the proposed centerline. Designating a route with a width of up to 500 feet will still give MnSP the flexibility to adjust the designated route to accommodate requests by individual landowners to avoid certain areas and to minimize the impact of construction on drain tile and other features.
7. A routing permit for the new pipeline should be conditioned in a number of respects, including imposition of those conditions specified in Minn. Rules part 4415.0195, an agricultural impact mitigation plan, and conditions agreed to by the applicant.
8. Any Finding of Fact more properly considered a Conclusion, or any Conclusion more properly considered a Finding of Fact, is hereby expressly adopted as such.

Based on the Findings of Fact and Conclusions contained herein and the entire record of this proceeding, the Environmental Quality Board hereby makes the following

ORDER

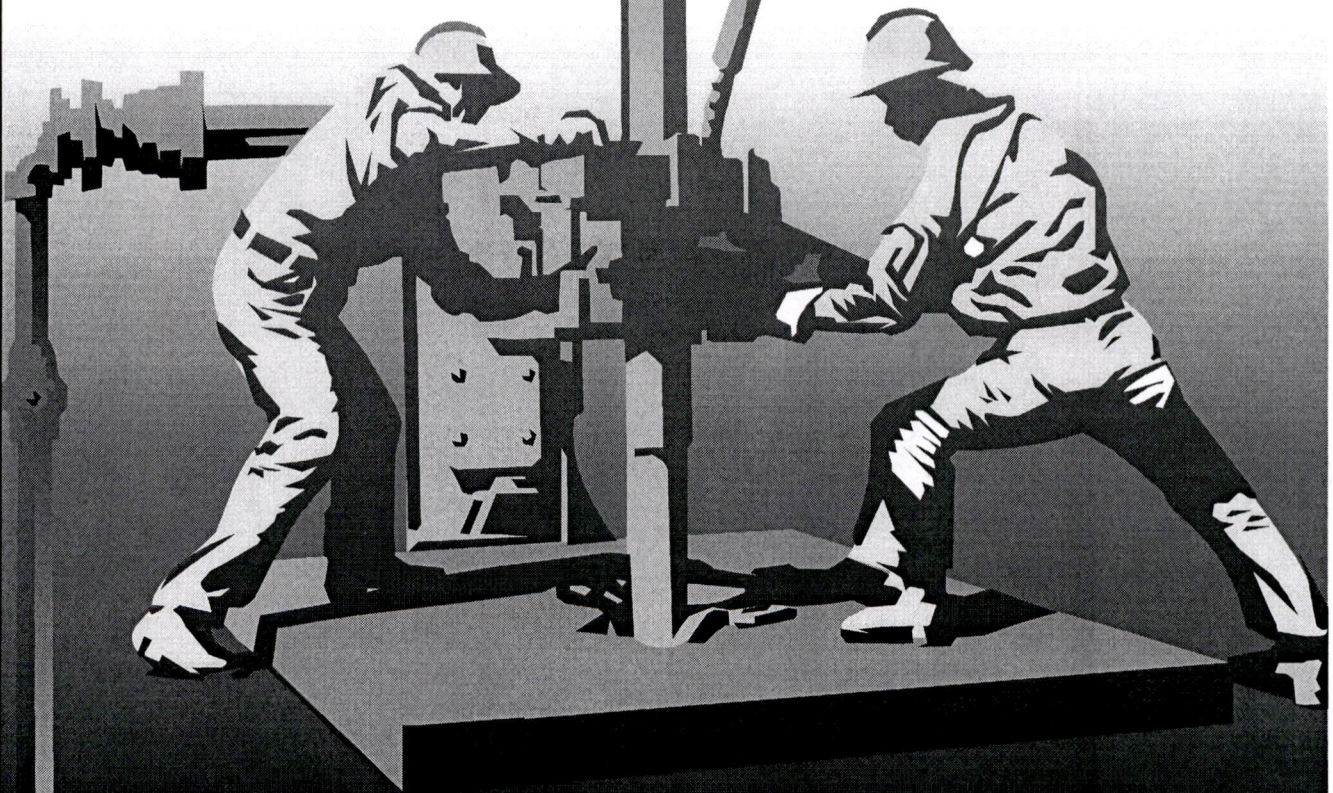
1. The Minnesota Environmental Quality Board hereby grants Minnesota Soybean Processors and Great Plains Natural Gas a partial exemption from the pipeline route selection procedures of Minn. Rules chapter 4415.
2. The Minnesota Environmental Quality Board hereby issues a pipeline routing permit to Minnesota Soybean Processors and Great Plains Natural Gas for construction of approximately 6.4 miles of natural gas pipeline and associated facilities along the route described in Conclusion No. 5 above. The pipeline routing permit shall be issued in the form attached hereto, including the description of the route with a width of up to 500 feet or 250 feet on either side of the designated centerline, and the inclusion of conditions.

Dated this 17th day of July, 2003

STATE OF MINNESOTA
ENVIRONMENTAL QUALITY BOARD

Robert A. Schroeder, Chair

Hints on Negotiating An Oil and Gas Lease



Judon Fambrough
Senior Lecturer and Attorney at Law

Technical Report 229

Real Estate Center

Director

Dr. R. Malcolm Richards

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Solutions Through Research

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Summary

From the mineral owner's perspective, an oil company seeking a lease is generally a welcome sight. The prospect of productive wells on the property could mean substantial income. Before exploration can begin, however, the mineral owner (lessor) and the oil company (lessee) must agree to certain terms regarding the rights, privileges and obligations of the respective parties during the exploration and possible production stages. The negotiation of these terms may be the mineral owner's first exposure to an oil and gas lease. Because of the legal nature of the leasing arrangement, an inexperienced mineral owner may be at a disadvantage when dealing with a more experienced lessee.

The purpose of this report is to acquaint nonexperts with the more common provisions of an oil and gas lease and explain their legal significance. The report details some provisions that the mineral owner may wish to insert for personal benefit and protection. However, the report is not a substitute for legal counsel.

Leasing Provisions

No standard or universal lease form is used by the oil and gas industry. Instead, each company (or independent lessee) has a predrafted agreement, usually some version of a Producers 88 Lease Form that has proven suitable to them in the past. The agreement may not necessarily be in the best interest of the mineral owners.

Mineral owners should remember that all provisions of a lease are negotiable. Even though the oil company representative or landman soliciting the lease may be unauthorized to make changes, certain clauses or even the complete lease may be altered. However, the mineral owner's ability to negotiate more favorable terms varies with each situation.

Three factors influence the negotiating power of the mineral owner. The first is the amount of acreage the lessor controls. The second is the proximity of the acreage to known production. And the third is the number of oil companies vying for the lease. The ideal situation for the mineral owner is to have a larger tract next to a newly discovered field with numerous oil companies seeking a lease.

If favorable terms are negotiated, they should be in writing and incorporated into the lease. There are three acceptable means of accomplishing this.

First, for minor modifications, strike the provision to be altered, insert the change and initial the margin of the page (both parties). Some authorities want the date inserted next to the initials. This process would be followed when changing the lease royalty from $1/8$ to $1/6$.

Second, for more pronounced modifications, attach an addendum to the lease. The preface to the addendum begins, "Notwithstanding anything to the contrary in the foregoing Oil, Gas and Mineral Lease, the following terms and provisions control. . . ." The individual changes are then listed.

If the addendum becomes quite extensive, and if it contains terms the lessee does not want to become public knowledge, a Memorandum Lease may be executed and recorded in its place. The Memorandum Lease contains the minimal information necessary to give constructive notice of the lessee's oil and gas lease. Generally, it will recite the name and address of both the lessor and lessee, the lease date, the length of the primary term and the legal description of the property.

Third, a way to make changes to a lease and, at the same time, to keep the changes from becoming public information is to enter a letter agreement. Letter agreements generally are used to clear up minor problems with the lease just prior to the commencement of drilling operations.

Granting Clause

The opening paragraph of the lease is the granting clause. It outlines the purpose of the lease and describes the substances that can be explored and produced. Typically, the clause will state that the lease is given for the purpose of exploring, drilling, mining and producing oil and gas and all other minerals, whether similar or dissimilar.

If substances other than oil and gas are produced, two problems become apparent in Texas. First, if the substances sought lie near the surface or will substantially damage the surface when produced, the substance may belong to the surface owner. (This creates a problem only when the mineral owner is not the respective surface owner.) Second, if substances other than oil and gas or associated hydrocarbons are discovered, will the lease cover them? (For more information, see *Minerals, Surface Rights and Royalty Payments*, publication 840.)

There are no easy answers, but here are some suggestions to consider:

- To avoid any dispute between the surface and the mineral owners, specify that the extraction method used by the lessee can be through a borehole only. Bar all strip mining and other methods that substantially destroy the surface. Mineral owners must realize that all substances lying beneath the surface do not necessarily belong to the mineral owner.
- Resolve speculation concerning the substances covered by the lease by specifying those included to the exclusion of all others, i.e., all petroleum and natural gas and related hydrocarbons except coal, lignite and uranium.

Granting Clause and Surface Operations

With few exceptions, the grant of an oil and gas lease carries the implied right to use

as much of the surface area as is **reasonably necessary** to explore and produce the oil and gas. Most leases expand these implied rights and explicitly permit a wide range of surface activities.

Even though the lessee may be liable for surface damages (see p. 7), the inconvenience of unwanted and unwarranted structures and entries upon the surface may be avoided to some degree by the following:

- Do not grant an unrestricted right for the underground disposal of salt water in abandoned wells on the property. Instead, state that prior written consent of the lessor is needed.
- Confine the lessee's routes of ingress and egress to existing roadways on the leased premises. If deviations are necessary, require them from the nearest roadway. Determine whether new roadways built by lessee must be removed when the lease terminates. Specify where cattleguards are required and who will maintain locked gates. Discuss erosion prevention techniques along roadways and around drill sites. For convenience sake, leases generally do not permit wells within 200 feet (or some other stipulated distance) of a dwelling. The mineral owner may want more distance. Further, provide that all underground transmission devices such as pipelines and telephone lines must be buried below plow depth (or a specified depth) in agricultural areas.
- Mineral owners wishing to cultivate or graze the area immediately above any pipelines should direct the lessee to use the double ditch method for laying pipe. This method requires the top soil to be placed on one side of the trench and the subsoil on the other. When backfilling, the subsoil is replaced first, followed by the top soil.
- In Texas, the lessee has the implied right to use caliche found on the leased premises free of charge for construction of drill sites and roads. The mineral owner may wish to alter contractually this rule in the lease.
- Specify that the lessee's structures and equipment **must be removed** within a certain time after the lease expires or be

forfeited. Otherwise, problems may arise concerning their ownership.

- Identify the parties liable for the construction and maintenance of fences and gates or similar structures around the premises, pits, drilling sites and above intersecting pipelines. The precise dimensions and characteristics of the fences and gates may need to be included.
- The mineral owner may require prior consent for conducting seismic or other geophysical operations. With the advent of three-dimensional (3-D) seismic, the potential for surface damages is significantly increased, adding to the importance of this clause.
- If the lessee must cut a fence to build a road or install a pipeline, describe the methods for bracing the fence prior to its breach.

Duration of the Lease

Leases are divided into two periods. The first period (primary term) is a set number of years negotiated by the parties during which drilling operations must begin or delay rentals must be paid. The lease generally states that if drilling operations are not being conducted within one year after the lease is entered, the lease terminates **unless** an agreed sum is paid to the lessor. This sum is called a *delay rental*. Delay rentals must be paid on each subsequent anniversary date of the primary term whenever drilling operations or production are inactive.

Failure to receive a required delay rental payment automatically terminates the lease whenever the word *unless* is used to indicate the necessity of the payment. Some leases contain the word *or* rather than *unless*. In the latter case, the lease will not terminate for a delinquent payment. Some leases have all the delay rentals paid in advance at the commencement of the lease. These are known as *paid-up leases*.

If production is not established by the end of the primary term, the lease will end. If production has been established, the lease will continue into its secondary term and last so long as substances covered by the lease continue to be produced. Generally the full clause will read, "This lease shall remain

in force and effect for a term of _____ years and as long thereafter as oil, gas or other mineral is produced from said land." Newer leases substitute the word *operations* for *production*. These leases read, ". . . as long thereafter as operations, as herein defined, are conducted upon the said land."

For protection, the lessor should consider one or more of the following recommendations:

- Strive to keep the primary term as short as possible. This will force earlier exploration.
- If the primary term cannot be shortened, strive to negotiate a higher annual delay rental payment.
- Make sure the word *unless* is used. Avoid using the word *or*. Keep a watchful eye on the date by which the delay rental payments must be received. Acceptance of a late payment may be construed as a ratification, and the lease will not terminate.
- Require the lessee, when tendering delay rentals, to identify the lease necessitating the payment. This is an invaluable aid for mineral owners trying to keep track of several different leases on their land, especially when all or part of a lease has been assigned to another oil company.
- State that the delay rentals must be received, not simply postmarked, on or before the due date. Delete any lease provisions requiring the prior notice to the lessee of nonpayment of delay rentals before the lease will terminate as drafted in a 12/79 Producers 88 Lease Form.

Extension of the Primary and Secondary Terms

The primary and secondary terms of the lease may be extended via the shut-in provisions, dry-hole provisions and cessation-of-production provisions. Most leases contain all three.

The shut-in provisions allow the lease to remain in effect whenever the production from a well is not being sold or used by the lessee. Only a well capable of producing in paying quantities may be shut in. A shut-in well, though, is classified as a producing

well, and the lease will not terminate as long as the shut-in continues. Even so, a shut-in royalty (generally a sum approximating the amount of the delay rental payment) must be paid annually after the expiration of the primary term to continue the lease.

The dry-hole provisions, on the other hand, will extend both the primary and secondary terms of the lease. Basically, the lease provides that if oil or gas **has not** been discovered when a dry hole is drilled, the lessee has several options for continuing the lease. First, in the event the primary term has not expired and more than 15 months still remain, the lessee has **two options**. The lessee either can pay the next delay rental payment that comes due 90 days after the dry hole was drilled or alternatively commence drilling or reworking operations on or before the next anniversary date occurring 90 days after the dry hole.

Second, if less than 15 months remain in the primary term, the lease will continue to the end of the primary term even though the lessee's operations remain idle and no delay rentals are paid. However, drilling or reworking operations must recommence on or before the end of the primary term to continue the lease.

Finally, if the lessee was in the process of drilling a well when the primary term ended, the lease will not terminate when the dry hole is discovered. Instead, the lessee has 90 days to resume drilling or reworking operations to continue the lease. (A 90-day period is the most common time frame. However, the period may vary from 60 to 180 days, depending on the lease.)

The cessation-of-production provisions correspond quite closely to the dry-hole provisions. The main difference is that the cessation-of-production rules apply **only after** oil and gas have been discovered. In this event, the lease provides that if oil and gas production should cease for any reason, the lease will continue if the lessee follows one of the options previously described for the dry-hole provisions.

It is theoretically possible for the lease term to be extended indefinitely via the dry-hole and cessation-of-production provisions. If the lessee has not discovered oil or gas, and if the lessee is in the process of drilling or reworking operations when the primary

term ends, the lease will continue in force for so long as the lessee faithfully renews drilling or reworking operations within 90 days after the termination of each operation. However, if a producing well subsequently should be discovered and its production later ceases, the lessee must again renew drilling or reworking operations within 90 days to hold the lease. Although the indefinite extension is theoretically possible, in reality it does not happen because of the costs involved.

More recent leases combine the dry-hole provisions and the cessation-of-production provisions under one general heading known as *operations*.

Most mineral owners usually do not disagree with the dry-hole and cessation-of-production provisions because, in either case, oil and gas are being sought diligently. However, mineral owners may have difficulty accepting the shut-in provisions, especially when no apparent reason for nonproduction exists.

Because of the high cost of bringing a well on line, shut-in provisions are used rarely except for the lack of a pipeline or buyer. Even so, mineral owners may wish to consider the following alternatives:

- Place a maximum limit on the shut-in, i.e., no more than three years or three years beyond the end of the primary term. Beware of placing a limit on the **consecutive** months for a shut-in without limiting the **cumulative** months.
- Possibly escalate the amount of the shut-in royalty payments for each year the gas or oil is shut in.
- As an alternative, permit the shut-in to continue after a stated period but only for a given number of acres immediately surrounding the well, i.e., 160 acres. The rest of the lease reverts to the lessor. (This provision may be qualified, depending on the reasons for the shut-in.)
- Because shut-in royalties are generally prepaid annually, confusion may arise if the lessee lifts the shut-in and produces during the year. Is the lessee allowed credit for both the money and the months that were prepaid but not used?

One alternative is for the lessee to prepay shut-in royalties monthly, not annually. Another is to require the lessee to account to the lessor for any months that were prepaid but not used at the end of each payment period. The failure to account causes a forfeiture of the unused months.

- Specify the circumstances when the shut-in clause may be invoked, i.e., for lack of market, available pipeline or governmental restrictions. As a possible alternative, permit the shut-in when, in the lessee's good faith judgment and with the lessor's consent, it is economically inadvisable to produce.
- Consider limiting shut-ins to gas wells only. Exclude oil wells from shut-ins.
- Automatically terminate the shut-in whenever a well located on adjacent land, situated within a certain number of feet of the leased premises and completed within the same producing reservoir, begins producing and selling gas in marketable quantities.

Royalty Clause

Each lease contains a paragraph that allocates to the mineral owner a certain portion of the substances produced. The allocation may be stated in terms of market price or value, proceeds or in kind. This is the *royalty clause*. From an economic standpoint, this may be the most important clause to the mineral owner.

The terms of royalty clauses vary from lease to lease. Through the evolution of court cases, the clause has been clarified in Texas. However, the mineral owner still should consider several items.

One consideration is expense that can be deducted from the royalty payments. The costs encountered throughout the exploration, drilling, production and marketing stages are divided into two categories:

- those borne solely by the oil company (producer) and
- those shared by the mineral owner.

All expenses encountered through the production stages are borne solely by the oil company unless the mineral owner has

purchased a working interest in the well. Expenses subsequent to production either can be shared or borne solely by the oil company, again depending on the terms of the lease.

If any costs are shared, the lessor's percentage is dictated by the size of the royalty. If the royalty is 1/6, the royalty owner's share is 1/6. By negotiating a larger royalty, the mineral owners, in effect, are agreeing to shoulder a greater percentage of the costs.

The shared expenses depend partly on where the lease fixes the royalty. Commonly, the royalty for oil is set "at the well" or "wellhead." In such cases, the mineral owner's royalty payment is free of production costs, but **all costs** subsequent to production are shared. (Two 1996 Texas Supreme Court decisions, *Heritage Resources, Inc. v. NationsBank*, 09-0515, and *Judice v. Mewbourne Oil Co.*, 95-0115, so held even though the lease addendum stated the royalty was free of such costs.) If the lease fixes the royalty "in the pipeline," "at the place of sale" or at other delivery points, different costs subsequent to production may be shared. These costs may include items such as compression expenses necessary to make the product deliverable into the purchaser's pipeline, expenses necessary to make the product salable, transportation costs and the expenses used in measuring production.

Another consideration for the mineral owner is determining how the royalty payment is valued or received. The leases generally provide three methods.

First, the mineral owner's royalty may be based on the "market price" of the product produced. *Market price* basically means the highest posted field price existing for the field. If there is no field price, then the value is determined by comparable sales in time, quantity, quality and availability. And if there were no comparable sales, the actual or intrinsic value of the substance is used.

Sometimes the posted prices are discriminatory, set artificially and substantially less than the prices paid for comparable minerals at other fields. In such cases, it may be possible to get a higher valuation for the royalty payments but only after a difficult burden of proof has been met by the mineral owner in a judicial proceeding.

To avoid the problem, a formula may be inserted to determine how the market price or value will be established. For example, some leases read, "at the highest price (or percentage thereof) posted for a field within 100 miles by any of the seven major oil companies for like grade and gravity on the day the oil is removed."

The second means of evaluating royalty is "proceeds." This method bases the royalty upon the actual revenue derived from the sale of the mineral. As such, the resulting sales price may or may not equal the mineral's actual market price as discussed earlier. In the past, royalties based on proceeds have been popular for marketing gas. By committing gas to long-term contracts, the producer could insure the mineral owner of a constant, dependable royalty income over time. The disadvantage was that the resulting proceeds were not immediately sensitive to a rising market.

The third method of receiving royalties is "in kind." This method presents an excellent alternative for dealing with a lease based on proceeds. By inserting an option to take royalties either "in proceeds" or "in kind," the mineral owner can get the best of both worlds. When the market price rises above any long-term commitment price, the mineral owner can take his or her share "in kind" and seek a market outlet. When the market price falls below any long-term commitment, the lessor's share can be taken in proceeds.

The in-kind, in-proceeds alternative is quite attractive to a mineral owner when one or more gas wells or pipelines are dedicated to the highly regulated interstate market. By the mineral owner opting to take royalty "in kind," the gas possibly can be sold on a more lucrative intrastate market. As a general rule, lessees are hesitant about granting this option unless the lease is in a major producing field. Otherwise, the cost of storage, accounting, delivery and other associated expenses will outstrip any gains to the mineral owner.

Briefly, the following factors may be considered when negotiating a royalty clause:

- Detail the time, place and frequency royalty payments are to be tendered. Outline the consequences for missing

royalty payments. Do not limit the penalty for a delinquent payment to interest only. Terminate the lease if the delinquency exceeds a stated period, such as 180 days. Should the lease terminate for nonpayment of royalties, make sure the equipment, tubing, casing and other machinery used in production are forfeited as well so the mineral owner may use them to withdraw any remaining oil or gas.

- Discuss whether or not the lessee has the right to disburse royalty payments. Some purchasers will give 100 percent of the proceeds to the lessee and require the lessee to pay the royalty owners. Operators have been known to keep the funds and disappear.
- Reserve the option to take "in kind" if feasible.
- Consider an extra royalty (or overriding royalty) based upon recovering all or a certain percentage of the production cost from the well. The overriding royalty also may be based on other variables.
- Determine if and when the mineral owner should have access to free gas. Many leases allow the lessor the free use of gas for domestic (and sometimes agricultural) purposes.
- By the same token, decide whether the lessee should have free use of water, oil and gas produced on the leased premises. (See p. 9 under the heading "Lessee's Right to Free Water, Oil and Gas" for further details.)
- Provide that costs subsequent to production may be deducted from the mineral owner's royalty, but that they will be reimbursed on a quarterly basis. This may be one way to avoid the effects of the *Heritage* and *Judice* decisions mentioned earlier.
- State that any division order tendered to the mineral owner after production begins cannot alter the lease. Texas law holds that any executed division order that contradicts the lease overrides the lease unless the division order conforms to the one described in Texas Natural Resources Code Section 91.402(c)(1). (See *Minerals, Surface*

Rights and Royalty Payments, publication 840, for more details.) Consequently, provide that if the division order, not in conformity with the statute, contradicts the lease, the mineral owner has the right to alter the division order to comply with the lease before executing it. If, by making the division order comply with the lease, additional charges are borne by the lessee, ask the lessee to agree to pay the additional charges in advance.

- Place a minimum royalty provision in the lease. A minimum royalty provision provides that unless a certain amount of revenue is received annually from royalties or other sources, such as shut-in royalties, the lease terminates. The minimum royalty provision prevents a small amount of production from perpetuating a lease for a large number of acres. (For more information, see *Termination of an Oil and Gas Lease*, publication 601.)

Surface Damages

Granting an oil and gas lease carries the implied right to use as much of the surface as is reasonably necessary for the development of the minerals. Only when the lessee goes beyond what is reasonably necessary, negligently injures the surface area or fails to accommodate estates will the lessee become liable to the surface owner for damages. Likewise, the lessee is under no legal obligation to restore the surface when production ceases. (For more information, see *Minerals, Surface Rights and Royalty Payments*, publication 840.)

For better protection, the mineral owner may wish to insert some provisions in the lease pertaining to surface damages. For instance, a lease clause requiring **compensation for all surface damages** will render the lessee liable even though the injuries were incurred during the reasonable development of the leased premises.

When compensation is required, it is commonly made at the site when drilling or production operations cease. To avoid any conflicts in this matter, the mineral owner should consider the following items when negotiating the lease:

- Require **compensation for all surface damages** such as injuries to growing crops and pastures; erosion and stagnation of the soil; growing timber; livestock; fences, ditches, canals, buildings and other structures; and the pollution of any surface or subsurface waters.
- Require the lessee to restore the land when operations cease.
- Describe the method or methods to be used for determining the extent of the damages. If the parties cannot agree, provide for some nonjudicial means of resolving dispute. Selecting an appraiser agreeable to both parties to determine the damages is a possibility.
- Determine if the compensation will be paid annually or in a lump sum. In part, this decision will depend on whether the damages are temporary or permanent.
- Resolve beforehand how payments will be distributed among the respective owners of the surface estate. This problem mainly arises when an agricultural lessee is on the premises.
- Designate the time by which all claims or notices must be submitted to the lessee and how soon thereafter the lessee must pay them.
- Possibly require a performance bond or an escrow account as security for payment of surface damages **before** drilling operations begin.
- Another possibility is to require a specific prepayment for each drill site in lieu of subsequent surface damages. Approximate the payment based on the fair market value of the land used for the drill site.
- If the lease is assigned, hold the assignor(s) and assignee(s) jointly and severally liable for surface damages. If this cannot be negotiated, require surface damages to be paid **before** the lease can be assigned. Otherwise, the lease may be assigned to a failing oil company that has no means of paying surface damages.

Pooling

Most leases will contain some provision giving the lessee the right to consolidate the

leased premises with adjoining leased tracts. The area thus formed is called a *pool* or sometimes a *pooled unit*. Pools are established to unite under one operator all the mineral owners having an interest in a common underground reservoir. By doing so, the lessee avoids unnecessary drilling, protects the rights of the mineral owners in the common reservoir and prevents waste. Pooling also permits the lessee to drill the best site otherwise prohibited by the state spacing requirement of 467 feet from a lease line. Sometimes pooling arrangements are necessary to meet the minimum acreage requirement for a drilling permit under Rule 37 of the Texas Railroad Commission.

In Texas, mineral owners may be subjected to two types of pooling. One is voluntary, and the other is compulsory or statutory. The voluntary arrangement requires the consent of the mineral owner and is generally found in the context of most lease forms. The statutory arrangement, on the other hand, is mandatory when the requirements specified in Chapter 10 of the Texas Natural Resource Code have been met. By entering either type of pooling arrangement, the mineral owner's share of the production will be determined by multiplying the lease royalty times the resulting fraction found by dividing the number of acres the mineral owner has in the pool by the total number of acres in the pooled unit.

Obviously, the mineral owner can do little to avoid compulsory or statutory pooling. However, the mineral owner may want to be cautious before consenting to voluntary pooling. The following suggestions may be helpful:

- In Texas, unless the mineral owner consents to voluntary pooling, the lease cannot be pooled. Consequently, the mineral owner may wish to withhold consent until the full impact of the pooling arrangement on the lease terms is understood.
- Alternatively, the mineral owner may consent to voluntary pooling in the lease but state that any pooled unit formed using the leased premises must contain a minimum percentage of the lessor's land.
- To limit a pool, stipulate the maximum acres a pool may contain. As a rule of

thumb, limit the acreage to no more than that specified in the Texas statutory pooling provisions, which is presently 160 acres for an oil well and 640 acres for a gas well plus 10 percent tolerance for each. However, where the field rules differ or where horizontal drilling occurs, allow the size to conform to whatever is needed for maximum allowables based on the rules of the railroad commission.

- If possible, negotiate all pooling prior to drilling operations and not afterwards.
- Consider whether or not the lessee may change the size or shape of the pool after the mineral owner consents.
- In all cases, negotiate the inclusion of a *Pugh clause*. A Pugh clause provides for the severance of the lease between the pooled and unpooled acreage whenever less than all of the lease tract is included in a pooled unit. The severance generally occurs at the end of the primary term or at the end of a continuous drilling program, whichever is longer. By having the severance, operations conducted on the pooled unit will not hold unpooled acreage and vice versa.

Without a Pugh clause, leases generally provide that any operations conducted on the pool shall be construed as operations on the entire lease tract. Therefore, production, drilling or reworking operations conducted on any portion of the pool, whether actually on the lease tract or not, hold the entire lease.

- On larger tracts, modify the Pugh clause for the severance between the acreage in a production or proration unit (whether pooled or unpooled) and the rest of the lease at the end of the primary term. It is possible to create a production unit using only the acreage from one lease. (This is known as a *tract well*.) In such cases, one well holds all the leased premises unless the wording of the Pugh clause is modified.

Assignment Clause

Typically, leases contain a provision permitting both the lessor and the lessee to

assign their rights and interest under the lease. To a large extent, these provisions are for the lessee's benefit to negotiate with other oil companies.

A customary practice is for an individual or independent oil company to lease a large tract and assign (sell) all or a part of it to another oil company. Consequently, the ultimate developer-producer may not necessarily be the original lessee. To retain partial control over assignments, the mineral owner may incorporate some of the following suggestions:

- State that the lessee must notify the mineral owner of any assignment. A 1989 Texas appellate case upheld the validity of a clause providing for \$1,000 liquidated damages if the lessee fails to notify the lessor of an assignment.
- Do not release the original lessee from liability for a default on any assigned portion of the lease or leased area. This is particularly important when surface damages and royalties remain unpaid.
- Nullify any assignment unless the production from a well exceeds a certain limit. Many times a marginal lease changes hands because another operator has discovered the "key" for making the well produce. The lessee will attempt production, fail and leave without paying royalties and surface damages.

Warranty Clause

Leases generally contain provisions requiring mineral owners to defend their interest in, or title to, the leased premises should an ownership dispute arise. This is known as the *warranty clause*. If the mineral owner breaches the warranty, the lessee has two alternatives. The lessee may sue the mineral owner for the return of any consideration paid for the lease such as bonuses, delay rentals or royalties. Alternatively, the lessee can reduce any payments forthcoming to the mineral owner according to undivided interest owned by the mineral owner in the property. For example, if the lessor owns half the minerals and purports to own all the minerals, the oil company may pay the lessor only half the bonus, half the delay rentals and half the royalties. The latter

alternative is described in a lease provision known as the *proportionate reduction clause*.

To avoid litigation, mineral owners should delete any language that infers they will warrant or defend the chain of title to the land. Instead, a limited or special warranty should be used. Because most oil companies or landmen generally conduct title searches prior to leasing, negotiating a special warranty should not be a problem.

Lessee's Right to Free Water, Oil and Gas

Mineral owners should pay close attention to lease provisions allowing free water, oil or gas to the producer for operations. In Texas, the oil company has the right to use fresh water, found either above or below the ground, for exploration and production purposes unless a change is negotiated. Particularly in areas where water is scarce, certain limitations should be placed on these rights.

- Decide whether free water, oil or gas privileges should be granted to the lessee. If so, stipulate whether the substances may be used for operations conducted both **on** and **off** the leased premises. (These provisions may be incorporated into the royalty clause as mentioned earlier.)
- If the land should contain a central supportive device, such as an oil-gas separator, prorate the free use of oil and gas needed to run the separator according to the amount of production from the leased premises if free rights are given.
- Do not allow the lessee to take free water from wells, tanks, ponds or reservoirs.
- Stipulate that any water use by the lessee cannot restrict the lessor's supply of fresh water for domestic, livestock or agricultural purposes.
- If secondary recovery operations are undertaken by the lessee involving waterflood operations, deny the use of potable water. State that such water must come from nonfresh sources.

- If water is to be purchased, state how the price will be determined. Many mineral owners sell the water based on the number of feet drilled for a vertical well, i.e., 10 cents per drilled foot. This method may be infeasible for a horizontal well because water usage is not always a direct function of drilled feet.
- Possibly require the lessee to drill a water well for drilling and production operations. The water well with all pipes, pump, casing and so forth reverts to the mineral owner when the lease terminates.

Force Majeure Clause

Leases generally contain provisions that protect the oil companies from liability and loss of the lease whenever causes reasonably beyond their control suspend operations. This is known as the *force majeure clause*. Mineral owners may consider several factors when this clause is proposed in a lease:

- Require a timely written notice of any sustained work stoppage. Require the notice to specify whether the stoppage was pursuant to the force majeure clause or the shut-in clause. The two generally overlap. However, a stoppage under the force majeure requires no payment while a sustained shut-in does. Consequently, if they overlap, provide that a stoppage must be governed by the shut-in.
- If an unavoidable stoppage should occur during the primary term, require delay rental payments anyway.
- Also, specify how soon operations must resume once the cause is removed. Some leases allow 15 months, but 90 days may be preferable.
- Consider whether financial difficulties, lack of water, lack of materials, lack of transportation facilities and so forth constitute a force majeure.

Horizontal Drilling

Two factors contributed to the Texas oil boom during the late 1970s and early 1980s. Foremost was the skyrocketing oil prices; the other was the intense drilling activity in the Austin Chalk.

Ten years later, a new mini-boom struck the oil fields. This time the price of oil was not a significant factor. Instead, it was the renewed drilling activity in the Austin Chalk spurred by a new technique known as *horizontal drilling*.

The Chalk is a narrow, cretaceous limestone formation running from Mexico through Texas. Its width varies from 20 to 30 miles. The formation is punctuated with numerous vertical cracks or fractures that harbor potential oil-producing veins.

Much attention was focused on the Chalk during the last oil boom because of a renewed emphasis on fracturing techniques. Fracturing (or fracing) is an artificial way to enhance the permeability (or flow) of the formation surrounding the well's perforation point. Fluids such as sand and water, polymers and even crude oil are pumped into the formation under tremendous pressure.

Fracing was important to the Chalk because conventional drilling could miss a vertical fracture by a few feet. An apparently dry hole could be transformed into a producing well if linkage between the borehole and the vertical fracture could be established. Thus, successful Chalk wells depended both on a correct location and the proper fracing techniques.

In 1989, a new drilling technique known as *horizontal drilling* was successfully introduced to the Chalk. The new technique eliminated the need for the drillstring to pierce the fractures vertically. By using redesigned tools, mud motors and flexible drillstrings, drillers could make a vertical hole gradually turn 90 degrees. The horizontal drillstring could be directed to intersect numerous vertical fractures.

Location is still important because costs are significantly increased. Beyond a 1,200-foot horizontal drainhole, the added costs may cause an unsatisfactory return on investment. However, a well was drilled in the Pearsall Austin Chalk Field having a 4,200-foot horizontal drainhole.

Horizontal drilling required the Texas Railroad Commission to develop new field rules to regulate the activity. In June 1990, Statewide Rule 86 became effective. Here is the basic concept.

First, the state-wide rules governing the spacing of vertical wells continues to apply

to horizontal wells. A vertical well must be 467 feet from a lease line and 1,200 feet from another well on the same lease. A horizontal well *and its drainhole* must continue to meet the same offset requirements.

Second, a horizontal drainhole with multiple completions in different fractures is still classified as a single well. Multiple drainholes in different directions from one vertical point are permitted.

Third, the size of proration units—the number of acres assigned to a well for purposes of allowables—remains the same as vertical wells. However, additional acreage may be added based on the length of the horizontal bore.

The amount of additional acreage permitted for a unit depends on the vertical field rules. If field rules for vertical wells permit units of 40 acres or less, an additional 20 acres may be assigned to the proration unit if the horizontal drainhole is between 100 and 585 feet. Thereafter, for each additional 585 feet (or any part thereof) drilled horizontally, another 20 acres may be added.

If field rules for vertical wells permit units of more than 40 acres, an additional 40 acres may be added if the horizontal drainhole is between 150 and 827 feet. Thereafter, another 40 acres may be added for each 827 feet (or any part thereof) the horizontal drainhole is extended.

Fourth, no acreage assigned to a horizontal well may be assigned to another well in the field. All assigned acreage must be considered reasonably productive.

To ensure compliance with the rules, the Texas Railroad Commission requires extensive surveys and plats to be filed with the commission indicating the location of the horizontal drainhole. No allowables may be assigned to any horizontal well until a proration-unit plat has been filed with and accepted by the commission.

Fifth, horizontal drilling increases the size of pooled units. Typically the pooling clause in a Producers 88 Lease Form provides that pooled units of a certain size for oil and another for gas may be formed by the lessee ". . . provided that should governmental authority having jurisdiction prescribe or permit the creation of units larger than those specified . . . [then] units thereafter

created may conform substantially in size with those prescribed or permitted by governmental regulations." Thus, the larger units are presently permitted by the lease terms.

To mineral owners, this means that a strongly worded Pugh clause is necessary. Otherwise, pooling a portion of a lease will hold on the entire lease tract.

Finally, horizontal drilling increases water usage. When the drill bit pierces a horizontal fracture, a tremendous amount of water is released with the drilling mud before the bit enters the other side of the fracture. Thus, as mentioned earlier, selling water to the lessee based on drilled feet may not be an accurate measure of the water used.

A Leasing Perspective

Oil wells are linked to visions of wealth. Consequently, when an oil company seeks an oil and gas lease, the mineral owner's perception may be distorted. The mineral owner may succumb to an oil company's bidding to sign the lease as quickly as possible. A hastily executed lease may turn a dream into a nightmare.

The mineral owner may want to consider at least two items before signing a lease. These include an examination of both the potential lessee and the lease provisions protecting the lessor's potential cash flows. A little investigative work at the start may lessen anxiety later.

First, scrutinize the lessee. Find out if the lease is being taken by an oil company or by an individual. If a company is taking the lease and if the words *corporation*, *incorporated* or an abbreviation thereof are used in the name, call the secretary of state, corporations division, and ask for the name and address of the registered agent. If the corporation has a duly authorized registered agent on file, the corporation is legally authorized to conduct business in Texas. No other questions need be asked of the secretary of state.

If the lease is being taken in an individual's name, inquire whether the individual intends to explore and produce the property or assign it. If an assignment is likely, find out who the assignee is. If the prospective assignee is a corporation, again call the secretary of state, corporations division, concerning its registered agent.

Once the ultimate producer is discovered, find out how many wells the producer has drilled, if any of the wells were drilled in the same formation as may be encountered under the leased premises and what the success rate was in the number of barrels of oil or cubic feet of gas produced. Obtain the names, addresses and phone numbers of the surface and royalty owners of the wells. Check with the individuals to see how they were treated, i.e., were royalties and surface damages paid in a timely fashion and were there any other problems? Finally, ask if any lawsuits are pending against the producer, where they are filed and what are the alleged offenses.

If an individual or newly formed company is taking the lease, prior work experience in the oil fields may be hard to trace. However, find out what oil companies have previously employed the individual and if the previous employers are still in business. Inquire about the names, addresses and telephone numbers of both the mineral and surface owners where the previous employer drilled wells. If the lessor uncovers a chain of dissolved companies and a history of dissatisfied landowners, the lessor may wish to seek another lessee.

Second, the mineral owner needs to examine the lease provisions to see if the potential cash flows are adequately protected. Even though the lessor may have provisions addressing the issue, they may be inadequate. To determine the adequacy, the mineral owner must grasp the difference between a lease covenant and a lease condition.

The difference between the two lies in the consequence for their breach. The breach of a covenant permits a lawsuit for damages, whereas the breach of a condition automatically terminates the lease.

Most of the lease provisions are covenants. There are only two conditions in the context of a Producers 88 Lease Form, i.e., one for failing to pay delay rentals and the other for failing to pay shut-in royalties. Consequently, if the lessee fails to pay production royalties or surface damages, the lease does not terminate. The lessor's only recourse is to sue for damages. If the lessee has insufficient assets to cover the judgment, the

mineral owner may never be compensated. The lessee is said to be "judgment proof."

At least four potential payments may be made to the mineral owner via the oil and gas lease: (1) bonus payments, (2) delay rentals and shut-in royalties, (3) surface damages and (4) production royalties.

The first two payments come directly from the lessee. Bonuses are tendered to the lessor at the beginning of a lease as an incentive to sign. Generally, the tender comes in the form of a sight draft, not a check, even though the draft may resemble a check.

The lessor is required to endorse the back of the draft just like a check. However, the lessor will not be paid once the draft is deposited. The bank receiving the draft will forward it to the lessee's collecting bank. After the specified number of *banking days* (not calendar days) indicated on the draft, the lessee must honor or deny payment. If denied, the lessor has no recourse against the lessee.

Sight drafts serve two functions. They allow the lessee time to check the lessor's title to the property and also to confirm that the lease is the same one negotiated by the parties.

The lessor may ask to be paid by check, but it is unlikely the lessee will consent. Consequently, the only factor left to negotiate is the number of days specified on the sight draft. Typically, the period is 30 banking days, which translates into 45 calendar days. The lessor may ask for a shorter period such as 10 to 15 days.

Recently, a Texas appellate court was asked to decide whether the lessor could execute a valid lease with another oil company after the sight draft was deposited but before it was honored. The court held that the lessor was free to sign with another oil company as long as the lessee was free to dishonor the draft without liability.

The second payments coming directly from the lessee are the delay rentals and shut-in royalties. These are described under the headings "Duration of the Lease" and "Extension of the Primary and Secondary Terms" (p. 3). Generally, there are no problems with either payment with older Producers 88 Lease Forms. Both are conditions. If the lessee fails to timely tender either, the

lease terminates. However, the newer Producers 88 Lease Forms, such as the 12/79, have provisions stating the lease will not terminate until the lessor informs the lessee of the nonpayment. The lessee has 15 days thereafter to cure the default. As previously stated, mineral owners may wish to delete such provisions or ask for an older lease form such as the 7/69.

The final lease payment coming directly from the lessee is surface damages. Generally, these are forthcoming when the well is plugged and abandoned or when a dry hole is drilled. Even though the lease may hold the lessee liable for surface damages, problems may still arise.

The problems are caused by the timing of the payment, the financial condition of the lessee when the payment is due and the fact that the payment is a covenant.

Because the surface damages are tendered toward the end of the lease, there is a likelihood that the lease has been assigned. The assignee (current lessee) will deny liability because the damages were caused by the assignor. Even if there has been no assignment, the current lessee may be judgment proof.

There is no ready solution. Even if the payment is changed from a covenant to a condition, there is little security because the lease is practically over by the time the payment is due. One solution is to make the payment a condition payable **before** drilling operations commence, not after production ceases. The amount of the payment generally parallels the fair market value of the land used for the drill site. Also, the lease may provide that no assignment is valid until surface damages have been paid. Mineral owners may inquire about the amount of surface damages the lessee budgets per well.

A similar problem confronting the lessor is restoration and clean-up costs. Although these are not a payment tendered to the lessor, they are covenants performable toward the end of the lease. If the lessee leaves without restoring the drill site and cleaning up, the only recourse is for the lessor to sue. As before, the lessee may be judgment proof. There is no readily available solution.

Royalty payments are the final payments the lessor may receive. These monthly

payments have the potential of exceeding all the other payments combined. They are payable once production commences. The royalty payment is a covenant, not a condition.

This payment may not come directly from the lessee. As a general rule, the purchaser of oil tenders royalty payments to the lessor, while the gas producer (or operator) tenders gas royalties.

Perhaps the sequence of events between the time production commences and royalty payments are tendered is confusing. However, the sequence must be understood if mineral owners are to protect their royalties.

When either oil or gas production commences in Texas, the producer must file monthly production reports with the railroad commission. Also, the producer must inform the commission of the purchaser's name and address. Both the production reports and the purchaser's identity are public information.

However, when the actual product reaches the purchaser, the similarity between an oil and a gas purchaser ends. A significantly greater burden is placed on the oil producer before the purchaser will relinquish payment.

As a general rule, the oil purchaser requires the oil producer to hire an attorney to render a division order title opinion based on the information currently recorded in the county deed records. The purchaser will then send division orders to the respective persons and entities indicated on the title opinion as owners of production. Ownership is stated in fractions carried to the seventh digit. Upon receipt of the executed division orders, the oil purchaser commences paying monthly royalties to the owners indicated on the title opinion.

On the other hand, gas purchasers disburse 100 percent of the proceeds from gas sales to the producer as the production is received. The gas purchaser requires no title opinion and no division orders. The gas purchaser may require the producer to sign an indemnification agreement if the purchaser is sued for the producer's failure to pay royalties or to pay the royalties in the correct amounts.

In some instances, the oil purchaser will relinquish 100 percent of the proceeds to the oil producer based on an indemnification agreement. This is generally the exception, not the rule.

The mineral owner must be cautious concerning a producer's ability to withdraw 100 percent of the proceeds or the producer's right to withdraw a share of the proceeds without giving the royalty owners the same privilege. The temptation may be too great for an oil company to use the royalty payments to bail itself out of a financial crisis or to abscond with the funds. Likewise, whenever producers can receive their portion of the proceeds without filing a title opinion, there is little incentive to pay the royalty owners.

As mentioned, the lessor may stipulate that the lease terminates if royalties are not paid within six months after production begins (see p. 6). This may provide inadequate protection.

The first six months of a well's production are critical because a well's revenue usually will be greatest during this period. Many wells may never reach pay-out status if they do not pay for themselves during this period or shortly thereafter.

Thus, the termination of the lease after six months of nonpayment of royalties is recommended. However, if the lessee can abscond with the funds in the interim, the lessor is not protected. The lessor must make sure the proceeds, at least the lessor's share, never leave the purchaser.

This is not to say that proceeds are absolutely protected with the purchaser. Charter Oil Company's bankruptcy in the early 1980s serves as a prime example. However, purchasers typically stay in business much longer and move less often than oil companies.

The difficulty lies in binding the purchaser to a lease provision stating that no royalties will be released to the operator. The purchaser is not a party to the lease agreement. Typically, the purchaser is totally unaware of the lease provisions. Consequently, if the purchaser releases all or a part of the proceeds to the lessee, generally the only recourse is to pursue the lessee, not the purchaser, for the royalties. One possible solution is to obtain the name and address of the purchaser from the Texas Railroad Commission and notify the purchaser of the lessor's right to receive direct royalty payments as soon as possible.

Other Terms for the Mineral Owner's Consideration

Without going into detail, the following terms may be considered by mineral owners when negotiating a lease.

- If the land contains several producing formations at varying depths, lease each strata separately. This is accomplished by negotiating a *horizontal severance clause*. If the severance cannot be based on formations, condition it on how deeply the lessee drills during the primary term.
- Insert provisions allowing free access to books, records and drilling data accumulated pursuant to operations conducted on the leased premises. Always try to obtain copies of the logs for the mineral owner's files.
- By the same token, obtain copies of all title opinions and abstracts of title acquired by the lessee. These will bolster the lessor's negotiating position with any subsequent lessee.
- If possible, negotiate some provisions whereby the mineral owner may assume control of the casing when operations are abandoned. The casing could be used to withdraw any remaining gas or extract fresh water for domestic or agricultural purposes. However, the mineral owner may be required to assume the cost and liability for plugging the well.
- Explicitly define when drilling operations commence. The criteria may be the time the well is spudded with appropriate equipment on site to drill to the depth indicated on the drilling permit. Otherwise, Texas case law is quite lenient and vague in defining the term.
- Define when a well is completed. This may be the time the drilling rig is released from the drill site. The definitions are indispensable when calculating the 90-day period between wells for continuous drilling operations described on p. 4.
- Require lessee to indemnify, save and hold lessor harmless from all claims,

demands and causes of actions stemming from activities undertaken by lessee or lessee's assignees, their employees, agents, contractors and subcontractors during operations conducted on the leased premises. Make sure the indemnification covers infractions of environmental laws. If possible, require the lessee to post bond and carry comprehensive liability insurance of a specified amount as added security from such claims.

- If a Pugh clause cannot be negotiated, never place noncontiguous tracts in the same lease. Otherwise, production from one tract or the pooling of one tract will hold all the noncontiguous acreage even though miles apart.

Conclusion

Negotiating an oil and gas lease requires legal knowledge, foresight and common sense.

No mineral owner could possibly hope to include all these suggestions in one lease. The provisions successfully incorporated depend upon negotiating power. Even so, the information contained herein describes some possible alternatives, and, if nothing else, will foster frank discussion between the mineral owner and the lessee prior to signing any agreements.

This report is for information only and is not a substitute for legal counsel.

The publications mentioned in this report are available from the Real Estate Center, Texas A&M University, College Station, Texas 77843-2115. Enclose a check in the appropriate amount.

Minerals, Surface Rights and Royalty Payments (Technical report 840, \$3 in Texas/\$4 outside of Texas)

Rights and Responsibilities of Mineral Cotenants (Technical report 843, \$3 in Texas/\$5 outside of Texas)

Termination of an Oil and Gas Lease (Technical report 601, \$3 in Texas/\$5 outside of Texas)

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Negotiating Oil and Gas Leases on Pennsylvania Farmland



Pennsylvania Department of
AGRICULTURE

Edward G. Rendell, Governor
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Disclaimer: This is intended for educational purposes only. Individuals with legal interests at stake should consult an attorney who is informed on these matters.

Introduction

The discovery of new accumulations, changes in the price of oil and natural gas, and advances in technology are forces that have encouraged widespread oil and natural gas leasing activity recently in Pennsylvania. Landowners in many Pennsylvania counties continue to have an opportunity to lease or convey the rights to oil and natural gas exploration and production. Granting of rights to test-drill and to produce oil and natural gas is an important transfer of property rights. This document is intended to provide some guidance to land owners when considering leasing options, it is not meant to be legal advice in any manner. A land owner is strongly encouraged to meet with an attorney or other oil and natural gas leasing experts prior to signing a lease.

Throughout this document, when the term lessee is used, it is referring to the company that has been given the right to drill. The term lessor refers to the landowner, the person who has been paid for the drilling rights.

One might say that the oil and natural gas producer/lessee becomes a "partner" in business. The main opportunity that landowners have to protect their interests in this partnership is through a lease. Landowners should also become fully informed about the rights and duties of oil and gas exploration and producing companies. All terms and conditions desired by the land owner should be addressed in writing in the lease as that is document that will govern the business relationship. Issues such as drilling restrictions, landowners' payments, drilling delays, property damages, and royalties from the actual oil and gas produced should be clearly stated in the lease. Lawyers experienced in dealing with landowner and lessee relationships as well as the production of oil and gas may offer many lease drafting suggestions that may benefit a landowner.

Signing a lease document may have implications not considered or fully understood by the landowner. A standard form lease offered by a landman may not offer all that can be negotiated by a lawyer experienced in protecting the landowner interests. A few of the issues for consider are such questions as: How will my farming operation be protected? Will this affect my "Clean and Green" status? Will I owe substantial income tax as a result of lease payments? Does the lease allow for the use of water from ponds, streams or wells on the property? What does it provide for in regard to timber removed during the well development? Does it address concerns for hunting and or fishing on my property? These are important considerations that should be addressed. The best way to ensure that your interests are protected is to consult with your attorney, accountant and other appropriate professionals before signing. In summary, **seek legal counsel experienced in these matters before signing an oil and gas lease**

It is also important to talk to other landowners (lessors) and learn more about their experiences with exploration and production and the royalties they received. A lawyer can clarify your rights, responsibilities, and risks under a gas and oil lease. For example, the landowner should be concerned about the potential for his or her liability for oil and other types of pollution under federal and state law. Individual landowners with small

parcels may join together with neighbors in order to pool resources for hiring lawyer with oil and gas lease and production experience.

Some other factors to consider are:

- The property owner must recognize that the lessee and future owners of the leasing rights have a long- term interest in the property similar to a utility with a right-of-way for an electric power line.
- Oil and gas leases are defined for a limited period similar to farmland leases. However, if production is initiated and continues at some acceptable commercial rate, the period of the lease is indefinite. In fact, options in many leases can extend the period of the lease when there is little or no production.
- Leases provisions should outline the timing and location of exploration and production activity, well sites, pipeline placement (including laying technique and depth), and roads (including specifics for damages to farmland, crops, and improvements).

Signing an oil and gas lease with the desired provisions may not be an easy decision. Landowners may be concerned about the possibility that a well may be drilled on a neighbor's property that draws from your property. Although it is true that if land is not under a pooling agreement through an oil and gas lease, the owner of the land will not receive a share of the royalty, it also is the law that a well bore can not extend on to your property with out a lease. The methods necessary for the extraction of gas from the Marcellus Shale only permit for the extraction of gas in close proximity to the well bores.

In an area where oil and gas reserves have not been proven, such as most of the Pennsylvania Marcellus Shale at this time, experts suggest that if production begins near your property, there will be a chance for leasing on the "second wave" of activity. With a second wave of activity, lease terms may improve compared with an initial leasing opportunity. The current amount of signing bonus, delay rental, royalty, other benefits, and damage provisions provided in the lease may be sufficient to convince a landowner to sign a lease now, rather than to wait for a better deal. The landowner should consider current and alternative uses for the land to be leased as well as the other considerations discussed here before signing a lease.

Considerations Before Signing

The following section outlines some factors for land owners to consider when negotiating a lease. This section is not comprehensive and may not address the unique circumstances for your farm.

Chances of Discovering Oil or Gas

When a landowner has a good estimate of commercially available oil or gas underlying his or her land and the cost of its production, a more informed leasing decision can be

made. There are several tools that can be used to make this estimate including reviewing existing maps and understanding leasing activity in your county.

Oil and natural gas companies will consult these maps and drilling records to determine locations that have good potential for profitable wells. Records and maps exist by county of prior drill sites and information on current and historical production. Geological consultants or petroleum engineers may review records and maps to develop an understanding of production possibilities and the potential for profitable production

Often an oil or natural gas company will conduct a seismic test prior to drilling. This testing may include the use of truck mounted equipment and explosive charges placed in strategic lines. The purpose of the seismic test is to use sound waves to get better readings on what materials lie deep beneath the surface.

Oil and natural gas companies may also develop a test drill site to detect the presence or absence of available oil or gas.

Maps and publications may be obtained from:
Pennsylvania Department of Conservation and Natural Resources, Bureau of
Topographic & Geologic Survey
3240 Schoolhouse Road, Middletown, PA 17057-3534.
Telephone: 717-702-2017
<http://www.dcnr.state.pa.us/info/ataglance/fstopogeo.aspx>

Pennsylvania State University Map Library
www.libraries.psu.edu/maps/

Reports on drilling permits and drilling activity are available from:

The Pennsylvania Department of Environmental Protection
<http://www.dep.state.pa.us/dep/deputate/minres/OILGAS/Reports.htm>

Pennsylvania Department of Environmental Protection
Bureau of Oil and Gas Management
Rachel Carson State Office Building
P.O. Box 8765
Harrisburg, PA 17105-8765
Telephone: 717-772-2199

Protection of Farmland and Improvements

When oil or gas is discovered and produced, cropping can continue with minimal damage and disruptions assuming the necessary protections are outlined in the lease. Farmers should learn the physical needs of exploration and production, such as equipment used, nature of well sites, roads, pipelines, and storage tanks. Farmers and landowners may wish to learn about existing Pennsylvania rules and regulations that govern well drilling, production, and restoration activity.

Information on Pennsylvania rules and regulations is available from:

Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management, Rachel Carson State Office Building
P.O. Box 8765, Harrisburg, PA 17105-8765
Telephone: 717-772-2199
<http://www.dep.state.pa.us/dep/deputate/minres/OILGAS/oilgas.htm>

Investigation of the Leasing Company

In Pennsylvania, companies can engage in oil and gas leasing without a license, bond, investigation or approval by any Pennsylvania agency. Landowners should seek information on the leasing company's reputation and performance. The initial lessee may be with a middleman (landman or broker) intending to sell leases to a drilling company. Ask the company agent for information, including people they have already signed leases with for references or how many wells they have already drilled. Farmers can save time and costs by pooling their efforts in conducting such an investigation, with the assistance of an attorney. Farmers' organizations, such as the Pennsylvania Farm Bureau, the Pennsylvania Farmer's Union and the Pennsylvania Grange may be helpful in this regard.

Oil and gas leases offered by companies and landmen are usually pre-printed forms that are likely to include terms favorable to the lessee. The lessee would prefer to use a standard-form contract to avoid drafting costs. Further, if leases are not similar, there may be difficulty in evaluating leases for subsequent sale or assignment to a drilling company. However, the lessor should know that any lease form can be modified or altered with addendums, containing provisions important to the lessor.

Evaluating Your Neighbors' Decisions

It is important that landowners discuss their options for gas drilling with neighbors and family. Doing so will allow you to become a more informed negotiator. Depending upon the nature of the lease and other factors, it may not be wise to sign a gas and oil lease just because your neighbor did. While it is possible that under the "Rule of Capture" a neighbor's well could draw from a reserve that underlies your property, in most instances the likelihood of this occurring is remote. You should investigate what techniques are being used to extract the oil or gas to determine the potential for this to occur. If there is a nearby "strike," the landowners with unleased land will probably obtain a more favorable oil and gas lease than those who sign early or do not bargain for detailed damage clauses or superior bonuses, delay rents, and royalties. The minimum

royalty payment to the landowner under Pennsylvania law, 58 P.S. § 33, guarantees a minimum royalty of one-eighth (1/8) of the “value of the production.” In many cases, leases are signed for much greater than the minimum royalty payment.

Landowners should request an explanation of how the value of production is determined. For example, in the case of natural gas production, what costs may be subtracted before the rate of the royalty is applied. In the case of natural gas, the value of the proceeds may be taken at a point remote from the land to which the lease is applicable. In short, processing and transportation or pipeline costs may be subtracted in arriving at the “value of production.” These are all items that may be negotiated in the lease agreement.

Decisions regarding when to lease and at what rates will be dependent upon individual circumstances. Consider the time value of money when making the decision to lease. Money at an early date may be equivalent to or greater than, a larger sum at a later date. But an outlook of rising oil and gas prices and higher royalties could convince a landowner that a delay could result in a larger sum in the future.

Another consideration is if a single lessee is unable to obtain a large enough area committed to leases, the lessee may not lease any land in a given area. If too few acres are under lease, the lessee may be unwilling to bear the overhead costs of exploration and test drilling. In effect, they may let the leases obtained go into default under the implied covenants of the lessee to explore and produce.

If a company is unable to secure a large enough area for production, the lease agreements may be sold or transferred to another company. Through these arrangements a company can obtain a large enough area to develop a production unit. Landowners should understand that in many cases the company that they negotiate the lease with may not be the same company that develops a well. Unless terms of the lease specifically require the lessor to approve the transfer of a lease, the landowner will have no say in who owns the lease and develops well sites. It is important to understand that no matter who owns the lease they will be bound by the terms originally negotiated when the lease was granted.

Seeking Legal Counsel

In many areas of Pennsylvania, the extraction of oil and gas, along with coal and other underground minerals, has been occurring for more than 150 years. Edwin Drake is credited with drilling the first oil well in the world in 1859 near Titusville in northwestern Pennsylvania. As a result of this previous activity, the mineral rights, including the rights to gas and oil, may have already been sold. If this has occurred, the current landowner may not have the ability to lease them or collect any royalties from gas or oil produced from their property. Additionally, the landowner cannot prevent the owner of these rights from extracting the gas or oil. Therefore, a landowner should verify the status of the gas, oil and mineral rights on their property and whether a lease may already be in place. The leasing company will take steps to check the landowner's title once a lease is signed. There are provisions in Pennsylvania law to help clear a landowner's title of dormant

mineral leases. A lawyer can assist in clearing up any doubt regarding severance of mineral rights or prior oil and gas leases.

In evaluating the legal aspects of oil and gas leases, experienced legal counsel will be helpful in drafting and negotiating specific provisions. Many of the ideas shared in this publication were obtained from the writings of lawyers and other professionals experienced in gas and oil leases and especially with the problems that may arise once the lease is in place and production begins. This publication does not discuss all the concerns that a property owner may have. A lawyer can help alleviate these concerns by drafting provisions into an oil and gas lease for a particular situation. Legal counsel may also be helpful after drilling and production operations begin, to insure that all provisions of the lease agreement are being met. Addressing the major issues in the lease is the best way to handle problems that may arise. Oil, gas and mineral laws are very complex. When choosing an attorney, ask them not only about their experience with oil and gas leases, but also the laws that govern the extraction and other aspects of mineral resources.

Tax and Estate Planning Considerations

Rental (delay or "shut-in") payments, bonuses, and royalties from gas and oil production are included as ordinary income for federal income tax purposes. The landowner may be able to deduct a portion of his real estate taxes against the rental income.

Royalties will be taxed as ordinary income. Net royalty income from oil and gas production may be reduced for federal income tax purposes by the **greater of a cost basis deduction** or a **percentage depletion allowance**. Unless a landowner allots some of the purchase price of his land to oil and gas deposits, there is no cost basis assigned to oil and gas that may be produced. For the lessor, the **percentage depletion allowance** is limited to 65 percent of **taxable income** for the year. The **depletion allowance** for oil and gas is 15 percent. The depletion allowance cannot exceed 100% of the **actual taxable income from the property before the depletion deduction**.

For example, a lessor/landowner has \$10,000 of royalties, taxable income from the oil and gas property of \$9,000 and total taxable income of \$30,000. The **tentative depletion allowance** is \$1,500 (15% of \$10,000). The **taxable income limitation** is \$9,000 (100% x \$9,000) and the **overall taxable income limitation** would be \$19,500 (65% x \$30,000). Neither **limitation** is a factor in this example, so the **depletion deduction** would be \$1,500. In this example, there was no cost basis for newly discovered oil and gas, so the cost basis deduction is zero. Thus the depletion allowance, as calculated, would be the applicable deduction--\$1,500 in this example.

Any depletion deduction taken reduces the taxpayer's basis on the property. The landowner needs to know his original basis (cost, ECT). Even though the depletion deduction can be taken beyond the taxpayer's basis, his basis could be reduced to zero creating a huge capital gain on the sale of the property.

Rental and royalty payments are also subject to Pennsylvania Personal Income Tax. The Pennsylvania Department of Revenue has issued a Statement of Policy regarding allowable depletion costs. The Statement of Policy can be found in *The Pennsylvania Code* (61 Pa. Code §§ 125.51. and 125.52). A link to *The Pennsylvania Code* can be found on the Department's website (www.revenue.state.pa.us).

Documents that convey title to real estate for purposes of the extraction of oil or gas are potentially subject to both State and local Realty Transfer Taxes. Such documents include deeds that convey a fee interest in real estate as well as a right of way or easement. Long-term leases (30 years or more) are also subject to tax, although leases that are solely for the production or extraction of oil, natural gas or other minerals are exempt from tax.

Additionally, if a family farm corporation or partnership permits the extraction of oil or gas on its real estate, the corporation or partnership could lose its tax exempt status as a family farm entity resulting in the assessment of Realty Transfer Tax on the entity's real estate.

Pennsylvania law does not currently provide for a severance tax on the value for all oil and gas produced in the State. It is possible that in the future if Pennsylvania enacts a severance tax, the lessor would be responsible for their prorated share of that tax. Landowners should consider including a provision in an oil and gas lease addressing the future levy of severance taxes due to gas and oil production.

Pennsylvania does not currently provide for the assessment of oil and gas for real property tax purposes. It is possible that in the future if Pennsylvania enacts property taxes resulting from gas and oil production, the lessor would be responsible for their prorated share of that tax. Landowners should consider including a provision in an oil and gas lease addressing the future levy of property taxes due to gas and oil production.

If the property is enrolled in the "Clean and Green" tax deferral program, the signing of an oil or gas lease may affect the status of the property, and could trigger a "roll-back" penalty. Before signing a lease the landowner should consult with the County Tax Assessor to determine what activities associated with oil and gas leasing and development will affect the "Clean and Green" status.

A farmer may consider including a clause in the lease that requires the lessee to be responsible for any repayments due as a result of a "Clean and Green" violation. This provision should also address any future increases in tax assessment resulting from oil and gas development. A landowner must realize that any payments received from the lessee in regards to changes in assessment must be treated as ordinary income for Federal Income Tax purposes.

Both income tax and estate planning may suggest shifting the income rights (if not full ownership rights) of oil and gas deposits to lower income family members. Special valuation of farmland for federal estate tax purposes does not apply to mineral rights.

If the land is being acquired under an installment contract, it is likely that neither buyer nor seller independently has the right to sign a binding lease. Mortgages may include a provision that limits the landowner/mortgagor's leasing rights.

Landowners must be cognizant of the fact that once a gas and oil lease is signed, the lessee's mineral rights take on an independent nature. The lease will be recorded at the courthouse in the county where the land is located, establishing an ownership interest in the landowner's chain of title.

A Farmer should be setting aside 35-40% of any bonus payments or royalty payments in anticipation of income tax that may be owed as a result of these payments. By planning for taxes owed, the farmer will not find himself in a position on April 15 with a large tax bill and no funds to pay it. This will result in payment penalties that could expand what is owned greatly. Seek the counsel of a tax professional before making decisions of how you are going to spend any money received as a result of an oil or gas lease.

Lease Document Considerations

This section outlines some more considerations to discuss when negotiating a lease.

Mineral Rights and Other Rights Granted

It may be in the best interest of the landowner to be sure that the oil and gas lease is limited in its granting clause to oil and gas and associated hydrocarbons. The lessee's standard lease form may include a grant of "other minerals." Royalties and lease provisions for oil and gas exploration and production may be inappropriate for certain other minerals. It is advisable to negotiate each mineral separately. Likewise, underground storage rights for natural gas should be separately negotiated.

Lessees may also attempt to convey the storage of gas in wells or underground formations. Proper compensation should be provided for storage if this is permitted. The landowner should require a separate payment for lessee pipelines not associated with their drilling running across his or her property.

Duration of the Lease

Oil and gas leases are drafted with a stated **primary period** (before production begins). As long as **delay rental payments** are offered or made as promised, drilling or production might not have to begin before the primary period ends for the lease to remain valid.

The lessee may suggest a long primary period, perhaps up to 10 years, which the landowner may feel is excessive for exploration or speculation. Three or 5 years may be a more favorable primary period. Landowners who are offered a nominal delay rental

payment may want to consider waiting for a better offer. It is important to recognize that the requirement to have proceeded with drilling is satisfied by drilling on any land included in a pool arrangement. The lessee need not have drilled or be producing in paying quantities on a specific parcel to keep that parcel owner bound by a lease. **Dry hole provisions** in a lease may require no delay rentals in the primary term once test drilling begins or during specified lapses between dry holes. Landowners can insist upon a clause which stipulates that the test well(s) must be drilled within a short period of time.

The lease may include primary term renewal or extension clauses. These clauses may give the lessee the option to renew the lease for an additional period at a specified rate, usually an amount similar to that which was paid initially. The lessor needs to pay careful attention to these clauses as they may allow the lessee to continue the lease for much less than the current value of leases. A more favorable renewal clause would be one that allows the lessee the option for the right of first refusal to lease the property at the current fair market value of the lease.

Typically, the **secondary term** begins with the drilling of a well and will continue indefinitely while there is production of oil, gas, liquid hydrocarbons, or constituent products in paying quantities. It is important to know what events will trigger the secondary term. A lease may include provisions which could tie up your property well beyond the primary period without receiving any royalty payments. It is important to understand what events will end the lease arrangement. This should be clearly spelled out in the lease

The landowner should understand who is responsible for terminating or ending the lease. The lease is a binding legal document that will be recorded at the courthouse in a similar fashion as a deed. When the lease has ended a similar document must be filed. Another potential problem could occur if after the lease is signed, the landowner does not receive the delayed rental payments. In many cases, it is the landowner's responsibility to notify the lessee of his intention to terminate the lease and to provide the lessee with a period of time, sometimes 30 days to make payment. If the landowner fails to do this, even though he has not been paid, he may not have the legal right to lease the property to another party.

Damage to Crops, Farmland, and Improvements

While oil and gas leases commonly provide payment for damages, it is also true that the lessee has considerable freedom to go on the leased land to explore or drill and produce. Further, Pennsylvania has rules and regulations for well drilling, dry holes, and producing wells. Pennsylvania rules require a \$2,500 bond per test hole or well site. Alternatively, there may be a blanket bond of \$25,000 for all wells drilled by the person for the duration of the bond. Pennsylvania regulations require the drilling company to restore the surface as nearly as practicable to the condition it was prior to the drilling of the well after completion and/or plugging.

The bond is subject to forfeiture should an operator of the well fail in adhering to Pennsylvania oil and gas laws. Funds from forfeited bonds are used to clean up sites on an environmental priority basis. It does not cover damages to fences, tile, crops, roads, soil, and buildings away from the dry hole or well site or to livestock. Additions to the Pennsylvania rules should be in the lease. Following is a list of specific provisions a landowner may want to consider.

a. Reserve the right to approve the location of drill sites, tanks, access roads, and pipelines. You may desire that a drill site to be a minimum distance from buildings and property lines. The reservation of location of a drill site is important to the landowner to maintain the value of his or her property. In fact, the landowner may be wise to limit the lessee to one drill site at a time--with consideration of the operator's performance from a preceding location. Lessee agrees to plan surface operations in a manner that will reduce or minimize the intrusion to crop fields. Although it may affect the value of a lease, a landowner may consider allowing for extraction from under their property while prohibiting the placement of wells on their property

b. Require all pipelines to be installed using the "double ditch method", where the top soil is placed on one side of the ditch and the sub-soil is placed on the other. When the ditch is backfilled, the sub-soil is replaced first, with the top soil placed on top. Also require that the pipe to be placed below tillage depth, or at a specified depth, such as 36 inches--safely below all possible tillage depths.

c. Require the drilling company to be accountable to the landowner for damages "to the surface of such lands or improvements or growing crops located thereon," unless the lease provides otherwise. The lease should be specific in making the company liable for all damages to growing crops, trees, fences, buildings, tile lines, drainage ditches, springs, water wells, any other improvements, livestock, and to the surface of the lessor's property. In the event that damage to crops and/or timber occurs, the farmer should be compensated for the damage or loss of growing crops at a current market value, over all of the affected growing seasons. Remember, the Pennsylvania Oil and Gas Act makes the driller liable to the State for various environmental damages, not to the landowner.

d. Require fences around all drilling equipment to help protect livestock or children and to prevent vandalism. Require that any fences or stone walls removed by during the operations be replaced or repaired and gates on all access roads.

e. Require that the lessee be responsible for any penalty that may be incurred in regard to the violation of the provisions of, including but not limited to Clean & Green, CRP, or CREP.

f. Require that any access road for drilling operations shall not exceed forty (40) feet in width during actual drilling operation and that outside roads from adjacent

properties shall not be constructed on the premises without written consent. The top soil removed for construction of the access roads should be placed beside the access road for restoration work after operations are completed. After well completion, an access road of a maximum width of 16 feet should be maintained for access to well for maintenance. Prior written approval should be required for the use of any existing roads. Repair of any damage to roads, caused by the drilling operations should be required.

g. Require that surface operations are conducted in a manner that will reduce or minimize erosion and sedimentation and that Erosion and Sedimentation Control Plan prepared for the site will implement and maintained

h. Require if appropriate, bio-security measures to protect livestock and poultry.

i. Require that water not be used from any wells, ponds, lakes, or reservoirs located on the premises without written approval.

j. Require that prior to conducting any seismic work a map showing the proposed location of each and every seismic line with consideration given to following existing roads, trails and paths be approved by the farmer. The landowner should receive compensation for any damage that occurs to as a result of this work.

k. Require the company to indemnify and hold the landowner harmless from all claims, demands, and legal problems and law suits, including violations of State and Federal laws and regulations, stemming from activities undertaken by the company or its assignees.

l. Require the lessee or drilling company to carry liability insurance as added security from claims by neighbors, government entities and others. Examples of problems that may arise include environmental law violations and interference with agricultural drainage systems.

m. Require that any water use by the company cannot restrict the supply of water for domestic, livestock, or agricultural purpose, and that the company shall not take water from wells, tanks, ponds, or reservoirs of the landowner without prior written approval. Additionally, the landowner should require that the lessee has obtained all required approvals for the use of water from the property.

Bonuses, Rents, and Royalties

A **bonus** (a one-time payment) is the term for the money provided to the lessor in return for the landowner's signature on the lease. It may be the initial year's rent and comparable to the **delay rental** mentioned above, or it may be some amount in addition to a first year's rent. If the modern practice followed the historical practice of only a few weeks or months delay before drilling, the bonus might be the only payment before royalties begin if there is a "discovery" or before there is abandonment and termination of the lease.

Modern practice and negotiations anticipate a delay of a few years before drilling and production or termination. Thus, the bonus and delay rentals may be more significant than in the past, because the landowner may have to lease for a primary term of 3 to 10 years or not at all.

Most landowners will feel that the nominal offer of \$25 an acre as a bonus or delay rental is not sufficient to commit their potential oil and gas reserves for the minimum one-eighth (1/8) royalty and risk damage to their property. Even if the damage is obvious, the landowner risks not being adequately compensated. Past reports from within Pennsylvania and nearby states are of bonuses ranging from \$25 to over \$3,000 per acre and delay rentals of \$25 to \$1,500 per acre. Logically, the greater the expectation of a discovery, the more likely a landowner may get a large bonus and a commitment for a substantial delay rental as well as other favorable provisions in the lease. Also, the higher the quality of the land for cropping purposes, the higher the bonus and delay rental ought to be.

"Royalty" has its roots in England, where that was the term for the share of production from mines or quarries reserved by the crown. In the 19th century, the amount for the landowner from oil production was set at 1/8th, or 12.5% and that is the minimum allowed under Pennsylvania law 58 P.S. § 33 "Guarantee of Minimum Royalties". Royalties up to 26% have been reported, but again, bargaining power for a higher than standard royalty may depend upon the expectation of a substantial discovery. Lessees who discover a large quantity available for production are in a better position to share a larger than usual percentage.

A landowner should consider the implications of royalty rates and what affect the rates may have on the landowner's long term income from their property. Penn State has a royalty calculator at <http://naturalgaslease.pbwiki.com/Royalty%20Calculator> where you can see how much difference royalty rates mean over the long term of the lease.

The initial lease payment for the primary term may seem generous. But when compared with the long-term implications of the royalty rate, it may be beneficial to accept a lower initial payment for higher royalty rates.

Rather than engage in lengthy haggling, a landowner might agree to a bonus, rental payment, and royalty that appears to be the lessee's limit, but only after obtaining a provision in the lease that requires the lessee to provide the same higher bonus, rent, or royalty that any other landowner might receive in a defined area. Landowners may want to require royalty payments on a monthly basis.

Access to Books and Records of the Drilling Company

The landowner should require a reasonable access mechanism to the books and records of the drilling or producing company so that he or she can evaluate the adequacy of the royalties received and obtain further information. This is another area where landowners might benefit from a cooperative effort to provide for an expert to examine books and

records on their behalf, because many landowners may not feel competent to audit lessee information. However, the landowner may find that "division orders" from buyers and other industry reports may provide satisfactory proof of the volume or quantity of production from his or her land.

Many of the drilling companies operating in Pennsylvania have moved here from areas such as Texas and Louisiana. The landowner should make certain that they do not have to travel to the "home-office" several states away to view these records.

Rights to Free Gas

Leases typically contain provisions for free use by the lessor of gas found on the premises. The free gas is usually only available to the landowner of the property where the well is located and not all the property owners in the drilling unit.

Before accepting a provision that provides for free gas, the landowner should investigate what steps they must take to utilize this gas. Things like expenses for installing and maintaining the equipment necessary to get the gas from the well to the farm and what liabilities the farmer will assume should be considered.

The landowner may want to consider a provision that provides for a payment in lieu of free gas. This payment can be an agreed upon lump sum or based upon a specific amount of gas at the current fair market value.

The farmer may be able to benefit substantially from the use of a supply of gas. Lessees will likely limit the lessor's free amount to that sufficient for a residence and will not pay for the pipeline from the well to the residence. A farmer may want to negotiate for the right to additional gas for livestock facilities and grain dryers at an economically advantageous rate.

Pooling Provisions

Most leases allow the drilling company to pool or form a drilling unit with lessor's land in combination with the property owned by adjoining landowners. Thus, when oil or gas is produced from any part of a drilling unit, all owners share in the proceeds in proportion to the amount of property they own in the unit.

As indicated above, pooling provisions may also limit the need to pay a delay rental to all members of a pool when drilling is underway on one parcel in a pool, yet keep all parcels bound under their respective leases at least throughout a primary period. Pennsylvania regulations do currently provide for minimum drilling units and well spacing for a very limited number of situations. You will need to know to what depth and the specific geological conditions of the drill site to determine if these regulations do apply. Much of the current and proposed drilling activity is not regulated as to drilling unit size and well spacing

Exercise caution in granting a company the unrestricted right to pool the leased premises, and in any event, be sure that you understand completely the effect of a pooling provision. You may limit your additional leasing opportunities as a result of receiving royalty payments on a small portion of your property.

You should consider submitting to pooling in the lease only to the extent necessary to meet the requirements of Pennsylvania law. In all cases, try to negotiate the inclusion of a "Pugh" clause in the lease that provides for the severance of the lease into separate tracts whenever less than the entire premise is included in a single pool or drilling unit.

Consent to Assignment of a Lease

Require that the landowner consent to any assignment of the lease or at least that he or she receive written notification of such assignment. The landowner may also wish to reserve a right to consent to the change of an operator.

Warranty Clause

To avoid possible litigation expenses, landowners should seek to delete reference in the lease that infers they will warrant or defend title to the land. The initial lessee is likely to complete some type of title check and prevent payment of any bonus until he or she is satisfied of a lessor's rights in the mineral interest for a specific parcel. But the lessee may miss or ignore a problem. The lessor under a warranty clause could be forced to defend title at a later date.

Termination of the Lease

If the lessee fails to comply with the stipulations in the lease such as payment of a delay rental, a landowner, with the help of legal counsel and a court proceeding, if necessary, may demand a termination of the lease because of breach. The lessee or his or her assignee may simply "give up" and let the lease "automatically" terminate by the provisions of the lease. It may be useful to have a provision in the lease which requires the lessee to record a release from the lease when it is clear that the landowner is entitled to a termination.

Failure of Implied Covenant to Drill

The Pennsylvania Supreme Court has recognized implied covenants or promises on the part of the lessee. First, there is an implied covenant to drill test wells within a reasonable time so that the purpose of the lease (production of oil and gas) can be fulfilled. If a landowner convinces a court of a lessee's failure under this covenant, there would be grounds for termination of the lease. This covenant may be more important for lease forms used in past years providing for an extended term without payment of a delay rental. However, this covenant may still apply in Pennsylvania even though the lease permits a delay during the primary period.

Failure of Implied Covenant to Develop

Second, there is an implied covenant to develop the leased premises as long as it might be profitable. This covenant suggests that a lessee must limit the delay following a dry hole if there is reason to believe that another test drill could produce a discovery.

Further, even if there is a substantial discovery, the driller may be compelled to drill additional wells unless he can show that more wells could not be profitable. Lease pooling provisions and Pennsylvania regulations may limit the duty of the lessee driller under this covenant.

Seeking Legal Counsel Before Termination

Before attempting to terminate an oil and gas lease, the landowner should consult an attorney as to the proper procedure pursuant to Pennsylvania Law. If the landowner desires to cancel his lease for failure to drill test wells, he or she must not accept delay rental payments or else the lease may remain in force and not be terminated on grounds of failure to develop. Refusing delay rentals may be most effective when the payments are late.

Taking Possession of a Well

After production operations are complete, drilling companies may offer a "non-paying" but producing well for sale or free of charge to the landowner. When the landowner takes possession of the well, the landowner takes responsibility for plugging the well, which may be expensive; and there may be increased exposure to environmental liabilities. Carefully investigate all the costs and benefits before taking possession of the well.

Conclusion

Oil and gas exploration and development has the potential to create many opportunities and challenges for Pennsylvania farmers. Because of the long term implications that these leases may have on current and future landowners, it is important that a potential lessor understand all the terms of a lease before they sign it. Review of the lease by an attorney experienced in oil and gas leases is the single most important step before signing. This review can be likened to an insurance policy. The money spent on a review by an attorney may be insignificant when compared with the potential problems avoided in the future.

A landowner should inform themselves completely on all the issues that are related to the signing of an oil or gas lease. Additionally, information may be obtained from the following sources:

Pennsylvania Department of Agriculture
2301 N. Cameron Street
Harrisburg, PA 17110
717-787-4737
<http://www.agriculture.state.pa.us>

Pennsylvania Department of Environmental Protection
Bureau of Oil and Gas Management
Rachel Carson State Office Building
P.O. Box 8765
Harrisburg, PA 17105-8765
717-772-2199
<http://www.dep.state.pa.us/dep/deputate/minres/OILGAS/oilgas.htm>

Pennsylvania Department of Conservation and Natural Resources
Bureau of Topographic & Geologic Survey
Jay Parrish, Director
3240 Schoolhouse Road
Middletown, PA 17057-3534
717-702-2017
<http://www.dcnr.state.pa.us/topogeo/>

Penn State University
College of Agricultural Sciences
Cooperative Extension and Outreach
Natural Gas Exploration and Leasing
Timothy W. Kelsey, Professor of Agricultural Economics
105-A Armsby
University Park, PA 16802
Phone: 814-865-9542
Email: tkelsey@psu.edu
<http://naturalgaslease.pbwiki.com/>

Penn State Dickinson School of Law
Agricultural Law Resource and Reference Center
228 Beam Building
University Park, PA 16802
814-865-3723
<http://www.dsl.psu.edu/centers/aglaw.cfm>

Disclaimer: This paper is intended for educational purposes only. Individuals with legal interests at stake should consult an attorney who is informed on these matters.

The information contained in this document is based upon multiple sources and to the best of our knowledge should be considered current as of July 2008.

This document was prepared by the Pennsylvania Department of Agriculture, D. Robert Davidson, Esq., Special Assistant to the Secretary, July, 2008.

This document is an adaptation of “*Negotiating Oil and Gas Leases on Indiana Farmland*” 1982, revised 1997 co-authored by Gerald A. Harrison, Extension Economist, Agricultural Economics Department, Purdue University, used here with permission.