Chapter I

Oil and Gas Development and Impacts

Oil and Gas at Your Door?

A Landowner's Guide to Oil and Gas Development

Second Edition

OIL & GAS ACCOUNTABILITY PROJECT

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Chapter I

Oil and Gas Development and Impacts

I

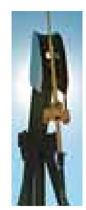
TERMS AND CONCEPTS
This first section is designed to introduce readers to some key terms and concepts related to oil and gas.

STAGES OF DEVELOPMENT
The chapter continues with explanations of the various stages involved in oil and gas development: from mineral leasing to the abandonment of oil and gas wells. Also included are some of the issues and impacts associated with these stages of development that may be of concern to landowners.

DEVELOPMENT OF NONCONVENTIONAL OIL AND GAS
This section introduces readers to the development of various forms of nonconventional oil and gas. These types of oil and gas deposits are likely to become more heavily exploited in the future.

IMPACTS OF OIL AND GAS DEVELOPMENT
This section provides information for landowners on some of the potential effects of oil and gas development on their lands, livelihoods and quality of life.

ALTERNATIVE TECHNOLOGIES—MINIMIZING IMPACTS
The final section provides an overview of some of the “best practices” or alternatives that are available to companies to minimize the impacts that their operations will have on the environment and the lives of landowners and nearby residents.



Terms and Concepts

Crude oil is the term for unprocessed oil, and it is also known as ***petroleum***. It is a mixture of molecules that are composed primarily of hydrogen and carbon atoms (***hydrocarbons***). Petroleum got its name from the fact that hydrocarbons are found in rock. The Latin words for rock and oil are *petra* and *oleum*.

Hydrocarbons are formed from dead plant and animal (i.e., organic) matter. Over time, these materials are covered by layers of sediment. The slow decay of the organic matter, aided by high temperatures and pressures, completes a long and complex process of transforming the organic material into hydrocarbons such as coal, oil and natural gas.

We often envision oil and gas reservoirs as being underground lakes of oil capped by natural gas (which is less dense, and therefore rises above the oil). In reality, oil and gas are most often located in the pores of rock. The beds of sedimentary rock in which the petroleum is formed are called the source rocks, and usually these are dark grey or black shales. Because petroleum is a fluid, it is able to migrate through the earth. Through time, the oil and gas migrate from the source shales, which are not very porous, into more porous or permeable rocks. Petroleum may end up in any porous rock, but it is most common to find large reservoirs of hydrocarbons in highly permeable, sedimentary rocks such as sandstone or limestone.

Most people have heard the saying "oil and water do not mix." When oil and gas encounter waterlogged formations, the oil and gas, because they are less dense than water, rise all the way through the water and settle as a layer on its surface. The hydrocarbons continue to move in an upward direction until they encounter a layer of material that is not porous, i.e., an impermeable layer. When this occurs, the oil or gas is said to be trapped. Occasionally, there may be a pathway (e.g., porous rocks or fractures) that extends all the way to the earth's surface. If this occurs (e.g., at a sedimentary rock "outcrop") hydrocarbons may be found seeping out of the ground.

Characteristics of Oil and Gas

Crude oil is a mixture of many different hydrocarbon compounds and other materials. Typically, crude oils contain: carbon (84%); hydrogen (14%); sulfur (1 to 3%); and nitrogen, oxygen, metals (e.g., nickel, iron, vanadium, copper, arsenic), and salts (less than 1%). Crude oil is processed to remove unwanted materials and produce useable "petroleum products" such as motor gasoline, diesel, jet and home heating fuels, waxes, asphalt, feedstock for petrochemicals, and other components.

The hydrocarbon molecules that make up crude oil can take on many different forms. The smallest hydrocarbon contains one carbon atom and four hydrogen atoms. It is known as ***methane*** (CH_4), and it is lighter than air. Longer chain hydrocarbons, with five or more carbon atoms, (e.g., pentane, CH_5) are liquids. Very long chains are solids like wax or tar.

In general, older and deeper hydrocarbon deposits contain oil that has: 1) low viscosity (which means it is more liquid than solid); 2) low density (which means it light); and 3) low sulfur content. These qualities make these old, deep deposits most desirable because they are easy to extract, they require little refining to remove sulfur, and they can be easily converted into high-quality products such as gasoline.[23]

Natural gas used by consumers is composed almost entirely of methane. When it comes out of the ground, however, raw natural gas is a mixture of gases and other substances. Methane is the predominant component of raw natural gas (70-90%), but the hydrocarbons ethane, propane and butane are also significant components (up to 20%). These hydrocarbons are often separated out at natural gas processing facilities.[24] Other substances may be present in raw natural gas such as water vapor, sand, oxygen, carbon dioxide, nitrogen, hydrogen sulfide, and rare gases (e.g., helium, neon).

Natural gas is considered ***dry*** when it is almost pure methane, having had most of the other commonly associated hydrocarbons and impurities removed. When other hydrocarbons are present, the natural gas is ***wet***.

Raw natural gas is produced from three types of wells: natural gas wells, oil wells and condensate wells. Natural gas wells primarily produce raw natural gas. In the other situations, natural gas is recovered along with either oil or condensate. ***Condensate*** is primarily composed of pentanes and higher hydrocarbons (e.g., hexanes, heptanes and octanes) that are in a liquid form when removed from the well. Condensate may also contain small amounts of the lighter hydrocarbons (e.g., ethane, propane, butane), as well as aromatic hydrocarbons (e.g., benzene, toluene, ethylbenzene and xylene), and hydrogen sulfide.[25]

When natural gas is produced from oil wells it is called ***associated gas***, while natural gas and condensate wells produce ***nonassociated gas***. Approximately 35% of natural gas recovered in the U.S. is associated with oil recovery.[26]

Sour gas is a highly undesirable type of gas to have produced near your property.[27] It contains high concentrations of hydrogen sulfide (H_2S), which is toxic, potentially fatal at certain concentrations, and has a vile odor, much like rotten eggs. If H_2S dissolves in water, it forms a mild acid that can corrode pipes, valves, meters and other gas handling equipment. Sour gas is commonly found in deep, hot, high pressure natural gas deposits such as the foothills of the Rocky Mountains in Alberta and northeastern British Columbia. In the United States, some production of sour gas occurs in Michigan and Texas. H_2S may also be associated with coalbed methane extraction. In Colorado and New Mexico, there have been numerous complaints related to H_2S contamination of water wells and migration into homes following coalbed methane development.[28] (For more information on sour gas, see the section on Impacts Associated with Oil and Gas Operations.)

Not surprisingly, the oil and gas industry has focused most of its attention on the deposits that are the easiest to find and extract, e.g., those in relatively shallow, highly porous rock formations. These are known as ***conventional*** accumulations, and they tend to exist in localized deposits. ***Nonconventional*** (also known as ***unconventional***) oil and gas deposits tend to occur over large geographic areas rather than in localized accumulations.

Historically, it was not possible to develop nonconventional deposits since the technology to do so did not exist, or it was much too expensive to access and process the oil and gas. Over the past two decades, however, improvements in technology have occurred largely as a result of government subsidies. As a result, nonconventional gas deposits have become a noticeable source of total U.S. domestic production.

The U.S. Energy Information Administration (EIA) predicts that natural gas production from nonconventional sources (tight sands, shale, and coalbed methane) is going to increase more rapidly than conventional production in the U.S. The EIA predictions show nonconventional gas production from the lower 48 states growing from 6.6 trillion cubic feet (tcf) in 2003 (35% of natural gas production in lower 48) to 8.6 tcf in 2025 (44% of lower 48 natural gas production). Industry experts expect a much faster growth in nonconventional gas production, predicting that more than 10 tcf will be produced in 2005.[29]

This guide focuses primarily on the development of conventional oil and gas deposits. Recognizing, however, that development of nonconventional resources is on the rise, Chapter 1 includes a section on Development of Nonconventional Oil and Gas.

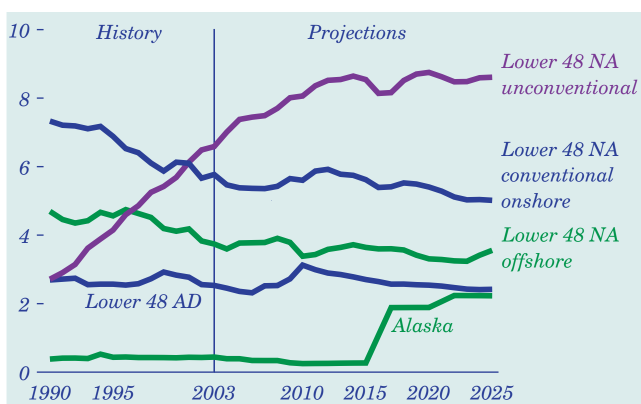


FIGURE I-1. NATURAL GAS PRODUCTION (CONVENTIONAL VS. UNCONVENTIONAL), 1990-2025. Note: AD stands for gas that is associated (dissolved) with crude oil production. Energy Information Administration.[29a]

Stages of Oil and Gas Development, 1.2.3.4.

Prior to the start-up of an oil and gas exploration or development project there are certain legal steps that companies take to prepare themselves. First, they must acquire the mineral rights to the targeted oil or gas deposit. Once the legal work has been taken care of, the technical work can begin.

The stages of oil development are similar to gas development, and include: 1) exploration; 2) field organization; 3) production; and 4) site abandonment. During exploration, a company will search for oil or natural gas deposits. If the company finds an economically viable deposit, production may occur. Prior to production, however, there may be an administrative stage that involves organizing the area where exploration has proved successful. During this period, efforts are made to ensure that as much oil or gas as possible will be extracted from the area. This is often referred to as field organization. When production occurs, the oil or gas is brought to the surface, and processing and refining take place. Finally, site abandonment, which typically involves plugging the well and doing some on-site restoration work, occurs when a well is no longer producing enough oil or gas to be economically profitable.

The oil and gas development process can span several decades, as some property owners have found out (see Terry Fitzgerald's story in Chapter IV). Below you will find detailed explanations of the processes involved in extracting oil and gas, as well as information on what you may experience if a company wants to develop a well on or near your property.

There are many publications and resources that provide greater detail on the oil and gas development process. For a listing of these resources, see Chapter V.

Obtaining Mineral Rights

Before companies may legally enter your property for exploration purposes, they typically must own or have leased the right to explore for minerals that are under your land, or have permission from the mineral owner to conduct exploratory tests.[30]

If you own the minerals

If you own the minerals beneath your land, you have a greater ability to determine if and how oil and gas development on your property will proceed than if you do not own the minerals. In order to explore or drill for oil or gas, the company will have to lease your mineral rights. You may refuse to lease those rights, or you may negotiate lease provisions that will help to protect your interests.

Mineral owners will often receive more than one offer to lease their mineral rights. This often happens well in advance of any actual development. Long before earth is moved or governments are involved, investors usually begin speculating about the next big oil or gas play, and may try to purchase the mineral rights over a large area.[31] The investors can then sell these mineral rights to exploration and development companies should the area prove to be a viable oil or gas field.

If you live in an area of known oil and gas deposits, it is possible that speculators have already leased the rights to minerals from prior owners (or your family members) under or near your property. Depending on when the leasing occurred, it is also possible that the lease terms may expire before development has a chance to occur. If this is the case, interested companies will have to obtain new leases before development may legally occur.

It should be noted that even if you own your land and the minerals beneath it, there are times when you may not be able to prevent exploration and development from occurring on your land.

In most states, something called force (or compulsory) pooling exists. In this chapter, the section on Field Organization provides information on forced pooling. Chapters II and III provide more information on mineral leasing, including Tips on Negotiating Leases.

If you don't own the minerals

If landowners do not own mineral rights to the oil and gas beneath their land, they do not have the legal right to stop a company from coming onto their land to explore for or develop oil or gas. This seems to put the landowner at a great disadvantage when dealing with oil and gas companies.

According to the Real Estate Center of Texas, however, if you don't own the mineral rights you still have options:[32]

1. Attempt to purchase all or part of an interest in the minerals beneath your land. By doing so, companies may have to negotiate with you in order to lease the property. You'll have more power if you own at least some of the mineral rights.
2. If all or part of the minerals cannot be purchased from the mineral owners, you may attempt to purchase the right of ingress and egress from them. Giving up this right does not affect the ability of the mineral owner (i.e., the ***lessor***) to lease the minerals and collect royalty payments from the company. But it would require the company who has leased the minerals (i.e., the ***lessee***) to make arrangements with you before entering to explore or develop a well on your property.
3. Contact the party who does own the minerals, and attempt to work out a land-use agreement. For example, you may ask mineral owner to restrict the company's operations to a certain section of land. Remember, however, that the mineral owner is under no legal obligation to enter into such an agreement.
4. Contact the mineral owner and work out a surface-use and surface-damage clause to be included in future leases between the mineral owner and an oil or gas company.
5. Attempt to negotiate a Surface Use Agreement directly with the oil or gas company. In some states this is required by law. There is more information on Surface Use Agreements in Chapters II and III.

Landowners should be aware, also, that there are laws and regulations that require companies to behave in an environmentally responsible manner; there are agency processes (e.g., permits) that may provide surface owners with the opportunity to comment on proposed oil and gas developments; and there are legal cases that have led to increased surface owner rights and protections. Chapters II and III provide more information on these topics.

1. EXPLORATION

Only after minerals have been leased (or permission obtained from mineral owners) may an individual or company go out onto the land to explore for oil and gas deposits.

Remote sensing techniques, such as photography, radar, infrared images, and microwave frequency receivers, are used to identify potential production areas and predict the likelihood of significant reserves.[33] Geophysical exploration is the attempt to physically locate oil or gas-bearing geological structures. The mostly widely used technique in on-shore geophysical exploration is the seismic test.[34]

Seismic Exploration

Seismic tests are based on the fact that acoustic or seismic waves will travel through, bend, absorb, and reflect differently off of various layers of subsurface rock. Seismic waves can be generated in several ways:

1. by blasting dynamite from a hole drilled several hundred feet in the ground;
2. by dropping a heavy weight, known as a thumper, from a truck (called a thumper truck) onto hard ground surfaces such as paved roads. This technique is known as land vibroseis, and it is typically used near populated areas and in sensitive environmental areas where explosions are not desirable;[35] or
3. by shaking the ground with a device known as a vibrasizer.

Seismic waves travel downward and outward, and are reflected back at different rates and strengths, depending upon the underground structures encountered. The strength and timing of the reflected signals are measured at the surface by geophones, which are connected to a line laid along a predetermined course. The line is connected to a machine that records the signals.

In the 1990s, geologists began using high-powered computers that could analyze much greater numbers of seismic signals and display them on three-dimensional (3-D) maps. To increase the detail and accuracy of these 3-D maps, the seismic lines and geophones are spaced more closely together, which means that land disturbance also increases.[36]

FIGURE I-2. SEISMIC EXPLORATION
30-ton thumper trucks leave lasting impressions on the surface.

Seismic Exploration—Issues and Impacts

- Survey stakes for mapping out the exploration area should be wooden, and not wire pin flags, because farming activities like making silage or hay can shred the wire flags. The resultant metal bits can kill livestock that eat the feed. Also, all stakes and markers should be removed after exploration is completed, because livestock and wildlife can die from eating ribbons or flags.[37]
- Seismic lines will destroy vegetation and may cause erosion, which could lead to sediment entering surface waters.[38]
- 3-D tests tend to cause greater surface disturbance and companies use your land for longer periods of time than with two-dimensional surveys.

- If dynamite is used during exploration, the "shot" holes may intercept the water table, and water may begin to flow or seep to the surface. These flowing holes have caused problems for some landowners, e.g., by making the land so wet that farmers were unable to cut hay.[39] These holes need to be plugged from bottom to top. Ensure that the company properly plugs and abandons these holes.
- Seismic work crews may generate different types of waste (plastic, paper, containers, fuel leaks/spills, food and human wastes).

Seismic Exploration—Tips for Landowners

- Prior to any exploration, it is advisable to ask the company to show you, on a map and on an aerial photograph of your property, where they intend to conduct their seismic operations. To minimize damage, try to ensure that work is conducted as far away from surface waters as possible. Ask companies to avoid steep slopes, as this could lead to erosion. As well, request that the company avoid any areas of ecological sensitivity or importance to your use of your land.
- Landowners may want to negotiate more payment and negotiate stronger surface-damage provisions if they consent to 3-D seismic tests, due to a greater degree of surface disturbance caused by this type of testing.
- It is advisable to get water wells tested before and after seismic testing, because seismic shot holes can provide a path for surface contaminants to come into direct contact with groundwater. The seismic explosions may also create pathways for water to flow to the surface, which could decrease pressure in the reservoir and affect water quantity in water wells. You can request that the company pay for these water quality and quantity tests.
- After the company leaves, do some ground-truthing: ensure that holes have been properly filled; that no flags, pins or trash are left around to endanger livestock or wildlife; and that water is not flowing into or from any holes.
- Review the state regulations governing exploration (contact state agencies to obtain copies of any regulations pertaining to exploration). There will likely be a number of things that the company is required by law to do (e.g., plugging of seismic holes; notification of exploration; posting a bond to cover potential surface damages, etc.). The more you know, the more you can ensure that the company is acting responsibly. For example, if notification is required before a company can enter your property, you may want to use the opportunity to make some requests of the company, e.g., negotiate a surface damage agreement, or right-of-way (access) agreement. Chapter II provides some information on exploration regulations in select states.
- In Wyoming, split estate surface owners have been placed in a lose-lose situation: if they allow exploration companies to place explosives on their property, they risk losing their homeowner's insurance; but if they oppose the testing in order to maintain adequate insurance coverage, they risk condemnation by the seismic testing company (under the eminent domain laws in the State of Wyoming). For more information, see "Wyoming Landowners Face Condemnation or Loss of Homeowners Insurance," in Chapter IV.

You may want to get your own survey done. The company may be more receptive to your wishes if you can demonstrate that your preferred access route or drill pad site is a technically sound alternative to the company's preferred location.

It should be stressed that geophysical techniques and remote sensing cannot identify oil or gas accumulations directly; they can only indicate the potential for reserves. The presence of oil and gas can only be confirmed by actual drilling. So, if the preliminary tests indicate a high likelihood of oil and gas, the company may decide to drill an exploratory well.

If the exploration activities have not provided sufficient indication of oil and gas accumulations, the exploration program will likely come to an end, and the leases held in the area will likely be dropped.[40]

Exploratory Drilling

The purpose of exploratory drilling is to verify: 1) if the geological formations have accumulations of hydrocarbons, and 2) if the site can produce enough oil and gas to make it economically viable to proceed with further development.

There are a number of steps in a drilling program. These include drill site selection; drill site preparation; rigging up; spudding in (i.e., drilling the well); and analysis of drilling data.

Drill Site Selection: Companies will choose a drilling site that allows them to easily (and cheaply) access the target geological formations. Surface conditions may affect where drilling can occur. Wells are usually drilled where there is a fairly level ground surface of sufficient size (several acres, typically) to accommodate the drilling rig, reserve pits, and storage space for the materials and equipment used during the drilling program.

Drill site selection can be an important issue for landowners. Landowners may not want to hear or see the drilling operations, or live with the noise or pollution associated with the heavy equipment. Also, the company's preferred site may cause damage to important areas on a landowner's property, such as crops or ecologically sensitive areas. Some types of formations allow for considerable flexibility in drill site location (e.g. coalbed methane) while others require more precision to hit the resources (e.g. some tight sands).

You may want to get your own survey done. The company may be more receptive to your wishes if you can demonstrate that your preferred access route or drill pad site is a technically sound alternative to the company's preferred location. See Alternative Technologies and Practices later in this chapter for information on directional drilling.

Drill Site Preparation: Drill site or well pad preparation is when the most dramatic changes to the surface are likely to occur. There may be a number of private contractors (or subcontractors) on site during this period, and heavy equipment traffic tends to be intense during this phase of development.

To start off, access roads have to be built. Thus, one is likely to see bulldozers, road graders and gravel trucks in the early stages of drill site preparation. Once access is provided, the drill site will be cleared of vegetation and leveled. A pad for the equipment may be built (often out of gravel) if there is concern about ground instability or if the ground is subject to freeze/thaw cycles.[41]

Pits may be constructed to contain water for drilling operations, to store drilling fluids, and to dispose of drill cuttings and other wastes. If required by government regulations, some or all of these pits will be lined with a clay or a synthetic liner. Alternatively, tanks may be brought on-site to store products used during the drilling stage, as well as any waste created during drilling.

When this work has been completed, the drilling contractor will move in with all the equipment required for the drilling of the well.

Rigging up: Rigging up includes erecting the drilling rig; installing equipment to supply electricity, compressed air, and water; and setting up storage facilities.

Drilling rigs operate the hoist that raises and lowers the drill stem and bit. For shallow wells, the drill rig may be self-contained on a single truck. Deep-well rigs, however, may have to be brought to the site in several pieces and assembled at the site. The rig is located and leveled over the main well hole, and all associated engines, pumps, and rotating and hoisting equipment are connected or positioned close to the rig. Water and fuel tanks are filled, and additives for drilling fluid are stored on location. Then, the drilling contractor is ready to begin drilling operations.[42]

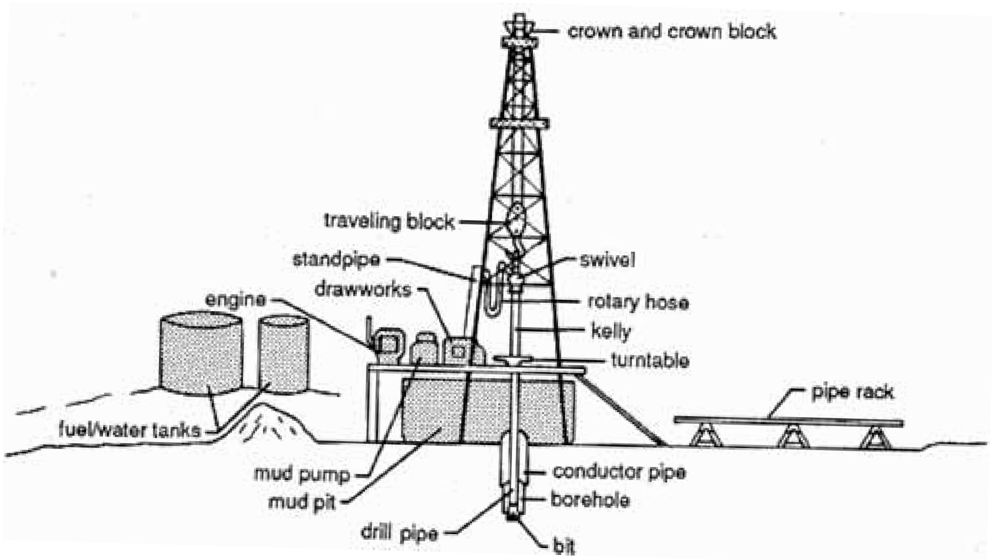


FIGURE I-3. A DRILLING RIG WITH ITS MAJOR COMPONENTS AND RELATED EQUIPMENT. Kansas Geological Survey[43]

Spudding in: Spudding in refers to the first stage of the actual drilling operation. When a well is spudded in, a large-diameter drill bit is used to drill a hole known as a ***well bore*** several hundreds or thousands of feet deep.

A system of pipes, flexible hoses and pumps draw drilling fluid from nearby tanks or a mud reserve pit. ***Drilling fluid***, also known as ***mud***, serves a number of purposes: 1) It is used to lubricate and cool the drilling equipment; 2) it circulates through the drilling system and returns to the surface, carrying ***drill cuttings***, which are fragments of rock generated by the drill bit; 3) it helps to prevent the fluids in the geological formations from entering the well prematurely; and 4) the pressure of the drilling fluid prevents the uncased well bore from caving in.[44]

Drilling fluids may be in the form of gases, foams or liquids. When drilling fluid is returned to the surface, it is piped to a device called a shale shaker, which separates the drill cuttings and solid materials from the drilling fluid. The fluid is usually returned to a mud tank or mud reserve pit to be re-used.[45]

Once the predetermined drilling depth is reached, the drill is removed from the well bore. The well bore is then lined with a steel tube (known as casing), in order to stabilize the hole and prevent caving. Casing should extend below the deepest freshwater zone, because another purpose of the casing is to protect underground fresh water sources from contamination by oil, gas or salty water that may flow through the well. Cement is pumped down into the space between the outside of the casing and the well bore. This is to further ensure the protection of groundwater, and to ensure that the casing is securely positioned.

A pressure test is then conducted on the casing and cement before drilling operations can be resumed. Also, a blowout preventer is attached to the top of the surface casing. This device is installed as safety measure to control the well if an abnormally high-pressure formation is encountered. If a high-pressure zone is hit, the blowout preventer can be closed to prevent gas, fluids and equipment from spewing out of the well bore.[46]

Once the surface casing has been tested and the blowout preventer installed, drilling operations can resume. The range in well depth is anywhere between 1,000 and 30,000 feet, with an average depth of all U.S. wells drilled in 1997 of 5,601 feet.[47]

Drilling Data Analysis: During drilling, there are a number of questions the company attempts to answer, such as: Is there oil and gas present, and if so, how much? How fast will the oil and gas flow? How do the oil- and gas-bearing formations vary from place to place? How much water is being encountered? (This last question is a big issue for coalbed methane development, because the water has to be pumped to get the gas out.) These questions must be answered before substantial investment is made in full-scale production facilities.

To answer these questions, the company's geologists will examine drill cuttings for signs of oil and gas. There are a number of additional tests that may be conducted to determine more detailed characteristics of the geological formations being drilled. These tests include coring, well logging, drill stem testing.[48]

If the company determines that there is not enough oil or gas to warrant production, all drilling equipment and materials should be removed from the drill site, and, depending on the state laws, the company may be required to restore the site as nearly as possible to its original condition.[49] Also, the drill hole should be cemented and plugged to prevent the contamination of groundwater and movement of fluids to the surface. In cultivated areas, the surface casing is often cut off below plow depth.

If the tests indicate that enough hydrocarbons are present to warrant commercial production, well production may begin.

For oil wells, it has been estimated that approximately only one exploratory well per every 10 drilled finds oil in sufficient quantities to justify production; and only one in 50 finds enough to repay the total costs of drilling the well and putting in the necessary infrastructure.[50] In coalbed methane fields the chances of drilling a producing, profitable well are much higher.

EXPLORATION STAGE—ISSUES AND IMPACTS

Surface and Other Disturbance

- There are various estimates of the amount of land disturbance associated with drilling for oil or gas. One oil or gas drill pad and the associated infrastructure may disturb anywhere from one to forty acres of land,[51] depending on the length of access roads, the size and number of storage and waste pits, etc.
- A study of oil and gas impacts on ranchers in New Mexico found that each pad removed between 2-4 acres from grass production.[52]
- Poorly constructed roads are prone to erosion, and heavy equipment causes soil compaction and decreased soil productivity. These impacts may be long term or even permanent.
- Quality of life may decline for landowners during the well drilling period, as 30-40 truckloads of equipment or water may be necessary to drill the well, and drilling operations tend to occur 24-hours a day (requiring lighting equipment at night), seven days a week until drilling is completed.[53] Heavy equipment used to construct the drill pad and access road will produce noise and dust. The noise level from equipment used during construction (if you are 500 feet away from the site) ranges from 60 to 70 decibels. That is somewhere between the noise that you hear if a car is passing you 25 feet away; or the sound you might hear in an urban shopping center.[54] Because construction often occurs through the night, this level of sound may be a nuisance to nearby landowners.
- The movement of equipment and vehicle traffic is a primary method of transporting seeds of noxious weeds and brush into an area. Furthermore, disturbed soils provide fertile ground for the establishment of weeds and brush.[55] Once they become established, non-native plant species can out-compete and eventually replace native species, thereby reducing forage productivity.[56]

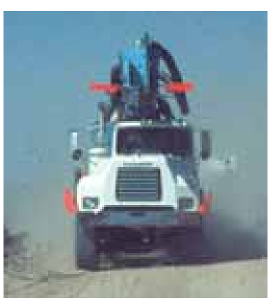


FIGURE I-4. DUST

- Camps for workers may be set up on a surface owner's property.
- If drilling does not produce a viable well, it is important to ensure that wells are properly plugged, and the site satisfactorily reclaimed.

FIGURE I-5. IMPROPERLY FENCED DRILLING MUD RESERVE PIT
Poses threat to wildlife and livestock.

Air Emissions

- Drilling operations produce air emissions from diesel engines and turbines that power the drilling equipment. The air pollutants from these devices may include: nitrogen oxides, particulates, volatile organic compounds, and carbon monoxide. Additionally, hydrogen sulfide may be released during the drilling process.[57]

Wastes

- When improperly drilled or cased, or when the casing has corroded, wells can serve as pathways for contamination of aquifers.
- There are numerous wastes that are commonly associated with drilling. These include: pipe dope, hydraulic fluids, used oils and oil filters, rigwash, spilled fuel, drill cuttings, drums and containers, spent and unused solvents, paint and paint wastes, sandblast media, scrap metal, solid waste, and garbage.
- According to the American Petroleum Institute, approximately 146 million barrels of drilling waste were produced in the U.S. 1995.[58] Drilling fluids and drill cuttings are the largest sources of drilling wastes.[59]

Drilling Fluid/Mud

- Drilling fluids or muds are made up of a base fluid (water, diesel or mineral oil, or a synthetic compound); weighting agents (most frequently barite is used); bentonite clay to help remove cuttings from the well and to form a filter cake on the walls of the hole; chrome lignosulfonates and lignites to keep the mud in a fluid state; and various additives that serve specific functions, such as biocides, diesel lubricants and chromate corrosion inhibitors.
- Whether the drilling muds are water-based, oil-based, or synthetic-based largely depends upon the drilling conditions encountered.
- Water-based muds (WBMs) are used most frequently. They are the least expensive of the major types of drilling fluids. This is mainly because water-based drilling wastes are less toxic than the alternatives, and often can be discharged on site. For difficult drilling situations, such as wells drilled in reactive shales, deep wells, and horizontal and extended-reach wells, WBMs do not offer consistently good drilling performance. For these types of drilling situations at onshore sites, the industry relies primarily on oil-based muds (OBMs).[60]

FIGURE I-6. DEWATERED DRILLING MUD
Is often buried on-site.

- Oil-based muds commonly are used while drilling deep wells, high-pressure shales, or during high-angle directional drilling because oil components (such as diesel or mineral oil) can avoid the pore-clogging that may occur with water-based mud. The downside of OBMs is the high cost, as well as the cost of disposing of the oil-contaminated drill cuttings, which contain hazardous chemicals, e.g., polycyclic aromatic hydrocarbons (PAHs), which may cause cancer, organ damage and reproductive effects.[61]
- Since 1990, the oil and gas industry has been developing a number of synthetic-based muds (SBMs), which are less toxic than oil-based muds. Instead of diesel or mineral oils, SBMs use internal olefins, esters, linear alpha-olefins, poly alpha-olefins, and linear paraffins. SBMs are free of PAHs, which decreases the toxicity of these muds.[62] Under certain circumstances, SBMs are used in place of OBMs or WBMs.
- Muds usually contain bentonite clay and other additives. Bentonite is a very expansive soil

material. This may create a site with the potential for great soil volume change, and possibly damage to surface structures. The common practice for disposing of drilling muds is to either bury the mud reserve pit, or discharge the mud to the surface. For landowners who may want to build on what was previously a drill site, it is worth noting that in order to be eligible for FHA mortgage insurance, all unstable and toxic materials must be removed and the pit must be filled with compacted selected materials.[63]

- Wastes that may be associated with drilling fluid include oil derivatives (e.g., PAHs), spilled chemicals, and empty containers.[64] Drilling muds that circulate through the well and return to the surface may contain dissolved and suspended contaminants including cadmium, arsenic, and metals such as mercury, copper and lead; hydrocarbons; hydrogen sulfide and natural gas,[65] as well as drilling mud additives, many of which contain potentially harmful chemicals (e.g., chromate, barite).

Drill Cuttings

- The main toxic agents in drilling cuttings are oil and oil products. These accumulate in the solid phase of drilling cuttings when crude oil and oil-based drilling fluids contact cuttings during the drilling process.[66] Rock cuttings may also contain arsenic or metals depending upon the geology.[67]
- Cuttings may be spilled around the well pad due to high pressures, dangerous working conditions, and lack of government oversight of drilling operations.[68]
- In West Virginia, the Department of Mines, Minerals and Energy (DMME) received complaints from residents about soap bubbles flowing from residential faucets. The DMME attributed this to the drilling process associated with coalbed methane well installation. Soaps and other substances are used to extract drilling cuttings from the borehole because the foam expands and rises. As it rises, it carries the cuttings to the surface. During drilling of the shallow portion of the well (and before the required groundwater casing is cemented in place) these drilling fluids may migrate from the borehole into the groundwater zone that supplies private wells. In the incidents of soap contamination in West Virginia, water was provided to the affected residents until the soaps were completely purged from the area surrounding their water well.[69]

Waste Disposal

- Onshore oil production operations produce quantities of cuttings and mud ranging from 60,000 to 300,000 gallons per day. Lined pits for disposal and storage are sometimes used, but mud, drill cuttings and other materials are often discharged into unlined pits, allowing potentially toxic substances to seep into the ground.[70] If improperly fenced, these pits can be a hazard for livestock and wildlife.
- While it is common for oil and gas companies to drain off fluids from drilling mud pits, it is very common for companies to simply bury the remaining solids in place or spread them on the lease site.[71]

Blowouts

- Well blowouts are rare, but can be extremely serious. Blowouts have been known to completely destroy rigs and kill nearby workers. They are most likely to occur during drilling, but can occur during any phase of well development including production (especially during well workover operations). If the pressure exerted by the geological formation is much higher than that exerted by the drilling fluid, then the gas, oil or other fluids in the well may rise uncontrollably to the surface. Equipment that is within the well may also be thrust to the surface. If there is a significant quantity of natural gas in the blowout materials, the fluid may ignite from an engine spark or other source of flame. Some blowouts are controlled in a matter of days, but others have taken months to cap and control.[72] The section on Impacts Associated with Oil and Gas Operations has more information on blowouts.

Surface and Other Disturbances—Tips for Landowners

- Revegetation of the pad surface and pipeline rights-of-way with native grasses is one of the best methods for controlling the spread of noxious weeds.[73]
- Lined pits or preferably tanks should be used to store spent mud, drill cuttings and solids, water used to wash any machinery, and surface runoff from the drilling area. These waste materials should be transported to a proper disposal site.
- Pitless or closed-loop drilling, which does not require pits for disposal of drilling wastes, is an option that reduces the potential for soil and water contamination. More details on pitless drilling are included in Alternative Technologies and Practices later in this chapter.
- Some traditional drilling fluid additives are toxic, but substitutes do exist: 1) replacement of chrome lignosulfonate dispersants with chrome-free lignosulfonates and polysaccharide polymers; 2) use of amines instead of pentachlorophenols and paraformaldehyde as biocides; 3) lubrication with mineral oil and lubra-beads instead of diesel oil.[74]
- Instead of disposing of drilling fluids in pits on-site, companies can use filtration processes to recondition the mud, so that it can be used for multiple wells before being discarded. Other possible uses for used drilling fluids include using it to plug unproductive wells or to spud in new wells.[75]

2. FIELD ORGANIZATION

This stage is primarily administrative, and usually involves government regulators. The purpose of field organization is to make the development of the oil or gas field more financially lucrative by creating a system for efficiently extracting the oil and gas from a particular region or field. Well spacing, pooling, and unitization are examples of organizational techniques that are applied during this stage.

It is during this stage of development that many citizens become involved because the impacts are broadly distributed over a geographic area (i.e., the oil or gas field), and governments often provide the public with an opportunity to comment on how the development might occur.

Well Spacing

Through well testing and geologic analyses it is possible to estimate the volume of oil and gas in a particular reservoir that can be drained by a single well, and then estimate how many wells will be needed to drain all of the oil or gas from the reservoir. Using these types of calculations, state governments determine how close together the wells need to be located (i.e., the well density) to most efficiently and economically drain the reservoir. The state agencies then define the number of wells that can be drilled in a specified surface area (usually per acre). The area allocated by the state for the drilling of an oil or gas well is sometimes referred to as the ***drilling unit.***

Typically, states enact spacing laws on a state-wide basis. States may also adopt different rules for particular fields.

- For example, in Colorado an operator can generally drill one well per 40 acres per formation anywhere in the state, unless there is an existing field rule in place, like the Ignacio-Blanco field rule in Southwestern Colorado. As of May, 2005, the Ignacio-Blanco field rule allows only one well to be drilled into the Fruitland Formation per every 160 acres.

Spacing rules apply to geological formations. That means if there are two or more formations that produce gas or oil in an area, then it is possible to end up with many more wells.

- For instance, in Southeast Colorado there are two major producing formations for coalbed methane: the Vermejo and Raton formations. In that region, an operator is allowed to drill two wells per 40 acres – one well to access the methane in the Vermejo formation, and one to access methane in the Raton formation. In that situation, however, the wells must be located on the same pad unless the operator gets a variance or exception to the rule.

Spacing requirements vary drastically from state to state. For example, in California, wells can be spaced as closely as one well per acre; while in Florida, gas wells are spaced at one well per 640 acres.[76] Shallow wells are usually spaced more closely together than deep wells. For more information on spacing requirements, the Interstate Oil and Gas Compact Commission has produced a summary of the various spacing requirements on a state-by-state basis.[77]

Downspacing and Public Health and Safety Concerns

In the 30,000-acre Jonah conventional natural gas field in Wyoming, industry hopes to use 20-acre well spacing (32 well pads per section of land) instead of the current 40-acre spacing. The industry proposal would increase six-fold the number of permitted natural gas wells in the Jonah Field (from about 500 to more than 3,000). If this were to occur, it is likely that air quality for the entire area would fail both national and Wyoming ambient air-quality standards. Consequently, in order to protect public health and safety, federal Bureau of Land Management officials have been discussing closing all public roads into the Jonah Field and forbidding any hunting or discharge of firearms in the 30,000-acre area.

Photo at right shows Jonah Field with 40-acre spacing of gas wells.

Adapted from: Taylor, Meredith. Fall, 2003. "Industry Stakes its Claim to the Upper Green's Public Lands,"[78] Photo credit: Image by SkyTruth for the Upper Green River Valley Coalition.

Well Spacing—Tips for Landowners

- Landowners should be aware that it is not uncommon for well spacing densities to change over time. While the state sets the initial well density requirements for an area, it is common for companies to later request that the wells be more closely spaced together. When states increase the number of wells that can be located in an area, it is referred to as ***infilling*** or ***downspacing***. Landowners who buy land thinking that there will not be oil and gas development on their property (based on current well density regulations) may be shocked to find that a few years after buying property the spacing regulations have changed, and that there are wells proposed on their land. See the story "County officials say residents ignored," in Chapter IV for an example of downspacing.
- Additionally, companies are sometimes exempted from the spacing requirements. A state's spacing regulations usually mention the conditions under which a company may be exempted from the spacing rules.
- Within the drilling unit, some states may designate a ***drilling window***, which is an area within a drilling unit where wells may be drilled. The location of the drilling window is dependent on a number of factors. In many states, wells cannot be drilled within a certain distance of homes. So, if there are a number of homes within a drilling unit, there may be a limited number of areas that can be used for drilling. In many states, however, it is not uncommon for com-

panies to apply for waivers, which allow them to drill outside the drilling window. Sometimes the waiver requires that if drilling occurs at a surface location outside the drilling window, the company must still hit the targeted drilling window at a certain depth (e.g., by using directional or horizontal drilling techniques).

Mineral Pooling

Often, mineral leases cover much smaller areas than the drilling units designated by the state. If this is the case, a company may pool two or more leases to create a tract that is sufficient in size to form a drilling unit for a single well.

- For example, in Colorado, an operator needs 40 acres to drill a well (unless there is a field-wide spacing rule in place). To obtain the 40 acres, the operator may have to lease minerals from 4 contiguous mineral owners that each own 10 acres. In addition to acquiring a minimum of 40 acres, those 40 acres may have to be located in a particular area. Typically, the 40 acres represent a quarter-quarter section of land (to ensure that drilling occurs in a uniform pattern of 4 wells per quarter section or 16 wells per section).

When mineral leases are pooled into a drilling unit, the mineral owners share proportionately in the proceeds from oil and gas production. For instance if you own 10 acres and are in a 40 acre unit, your income will be figured as 1/4 of the unit's production multiplied by your royalty interest.

Before a company can develop on a pooled unit, approval must be obtained from state agencies. It is sometimes the case that not all mineral owners within a drilling unit want to pool their minerals to allow for oil and gas extraction. For example, they may want to wait until gas prices are higher before they develop their minerals, or wait until technologies can be developed that cause less impact on the surface property. Unfortunately, for mineral owners who want to resist development of oil and gas, many states have what are known as ***force pooling*** laws. These laws allow mineral properties to be pooled into a drilling unit and developed without the consent of all of the mineral owners.

Force pooling laws can be of assistance to mineral owners who are concerned that their oil and gas resources are being removed without any compensation. When companies drill for oil or gas on a particular property, they will usually drain the resources that are located adjacent to that property. If mineral owners suspect that a well on a neighboring property is draining the oil or gas on their property, they can go to the state agencies (usually oil and gas boards or commissions) and request that the company be forced to pool their minerals with their neighbor's minerals, thereby allowing them their share of the profits.

Mineral Pooling—Tips for Mineral Owners

Participate in pooling hearings. When a pooling application is filed by a company, a hearing is held by the state to determine whether the pooled unit complies with the pertinent laws. These are the hearings that mineral and surface owners should attend if they want to protest the pooling terms. If mineral owners do nothing, they will be deemed to have accepted the terms approved in the hearing.[79]

In many states, these hearings are not held in the mineral owner's community, but rather, are held in a larger city (often the state capital), which does not make it easy for mineral owners to participate. In Michigan, a bill was passed in 1998 that helped to lessen the burden on mineral owners who were being force pooled by energy companies. This law moved the administrative hearings from the larger city to a community in the mineral owners' region.[80]
If mineral owners have not yet leased their mineral rights, and they are approached by a company about leasing, they are usually presented with three options.

1. Negotiate and sign a lease and take the offered bonus and royalty interest.
2. Decide to not sign and likely be force pooled under terms established by the state.
3. Elect to participate in the well and pay their proportionate share of the drilling and completion costs in order to receive their pro rata payout as a working interest owner.

It is important to look into the pooling laws in the state where your property is located, or talk with a lawyer, in order to evaluate which of these options works best for you.

For more resources on force pooling, see references to East of Huajatolla Citizens Alliance information sheets in Chapter V. And for landowner experiences with force pooling, refer to Chapter IV stories: “Threats and Intimidation—This is Called Negotiation? Force Pooling an Affront”; “State Could Force Property Owners to Allow Drilling”; and Terry Fitzgerald’s story.

Unitization

Unitization is the process of bringing together a group of drilling units (see pooling above) to form a large operating area. Typically, there are several operators in the operating area. Unitization takes place through an order from a state agency, and participation by operators may occur either voluntarily or involuntarily. Unitization orders may specify things such as well spacing or extraction rates in order ensure that all operators are working together to efficiently and effectively remove the oil or gas from the operating area. Unitization often occurs when an older field's production has begun to decline and it is necessary to utilize secondary recovery practices such as water or CO_2 flooding techniques to stimulate more production. As a result of a compulsory unitization statute for oil and gas reservoirs, Louisiana's oil and gas wells are, on average, one-third more productive than those in Texas, which does not require unitization.[81]

For more information on spacing, pooling and unitization (including federal units), visit the OGAP website (www.ogap.org).

3. PRODUCTION

The first step in production is to complete the well and start the well fluids flowing to the surface. Stimulation techniques may be used to enhance the flow of fluids during well completion. Once the fluid begins flowing, it must be separated into its components of oil, gas, and water. Finally, the oil and gas are treated, measured, and tested before being transported to the refinery. In addition to extracting and transporting the oil and gas, other tasks carried out during the production stage include: production enhancement, which uses techniques similar to those used to stimulate wells; well servicing, which includes routine maintenance operations such replacing worn or malfunctioning equipment; and well workover, which is more extensive equipment repair.

Well Completion

To begin completing a well, casing material (usually steel pipe) is inserted into the well bore. As with the casing used during the drilling stage, the casing material is supposed to prevent the oil or gas from contaminating groundwater, and stop the walls of the hole from collapsing. Cement is pumped down the casing to fill the space between the casing and the walls of the drilled hole. This is done to protect the casing and to further decrease movement of oil, gas or other fluids into ground water or rock formations.

When cementing of the casing is completed, the drilling rig and other associated equipment are removed from the site, and a smaller rig (a workover or completion rig) is moved over the well bore to finish the well completion. This rig is used to puncture or perforate the casing at specific locations where the casing comes in contact with the formations that contain oil or gas. The oil and gas can then enter the well through these perforations.

Next, tubing, which will carry the oil or gas to the surface, is threaded into the casing. At the surface, a well head (sometimes referred to as a Christmas tree) is installed, which has valves that control the flow of oil or gas from the well. The valves connect the well to equipment that will separate the oil, gas and water, and remove impurities. Finally, a pipeline connection or storage tank is connected to the well to allow for transport or storage of the product. In the case of natural gas, which cannot be stored easily, a pipeline connection is necessary before the well can be placed into production.

If there is not enough pressure in the reservoir to force the oil, gas or produced water to flow naturally to the surface, pumping is necessary.[82] Pumping equipment is installed at the lower end of the tubing. There are many different types of pumps that can be used: beam pumps; gas lift: piston pumps; submersible pumps; jet pumps and pneumatic pumps. The power to operate these pumps may be supplied by a gas or diesel engine or an electrical motor.

A number of pits may be constructed at this stage. These may include a skimming pit, which reclaims residual oil removed with produced water; a sediment pit, which stores solids that have settled out in storage tanks; or a percolation or evaporation pit, to dispose of produced water.[83]

FIGURE I-7. CHRISTMAS TREE
The wellhead of a gas well. The first step as natural gas leaves the ground. Photo by OGAP.

FIGURE I-8. MUD RESERVE PIT
Torn liners can lead to groundwater contamination.

FIGURE I-9. WASTE PIT
Waste pits for fluids and sediments associated with gas processing. These can contain water, sand, hydrocarbons, glycol and other chemicals.

Stimulation

Often an oil- or gas-bearing formation may contain large quantities of oil or gas, but have a poor flow rate due to low permeability, or from damage or clogging of the formation during drilling.[84] This is particularly true for tight sands, oil shales and coalbed methane, discussed later in this chapter. Stimulation techniques may be used prior to production, or during maintenance operations that take place after the well has been put into production. In later years, when the flow of oil or gas from a well begins to decline, stimulation techniques, as well as other enhancement techniques, may be used to encourage oil or gas to flow to those wells. Some of the more common stimulation techniques include: hydraulic fracturing; acidizing; and cavitation, which will be described in the section on coalbed methane.

Hydraulic fracturing (also known as fracing, which rhymes with cracking) is a technique used to create fractures that extend from the well bore into rock or coal formations. These fractures allow the oil or gas to travel more easily from the rock pores, where the oil or gas is trapped, to the production well.[85] Typically, in order to create fractures a mixture of water, proppants (sand or ceramic beads) and chemicals is pumped into the rock or coal formation. Eventually, the formation will not be able to absorb the fluid as quickly as it is being injected. At this point, the pressure created causes the formation to crack or fracture. The fractures are held open by the proppants, and the oil or gas is then able to flow through the fractures to the well.[86] Some of the fracturing fluids are pumped out of the well during the process of extracting oil, gas and any produced water, but studies have shown that anywhere from 20-40% of fracing fluids may remain underground.[87]

Acidizing involves pumping acid (usually hydrochloric acid), into the formation. The acid dissolves some of the rock material so that the rock pores open and fluid flows more quickly into the well. Fracing and acidizing are sometimes performed simultaneously, in an acid fracture treatment.[88]

Stimulation—Issues and Impacts

Potential Groundwater Contamination—Coalbed fracture treatments use anywhere from 50,000 to 350,000 gallons of various stimulation and fracturing fluids, and from 75,000 to 320,000 pounds of proppant during the hydraulic fracturing of a single well.[89] Many fracturing fluids contain chemicals that can be toxic to humans and wildlife, and chemicals that are known to cause cancer. These include potentially toxic substances such as diesel fuel, which contains benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals; polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide.[90] Very small quantities of chemicals such as benzene, which causes cancer, are capable of contaminating millions of gallons of water.

FIGURE I-10. FRAC PIT
Unlined pits may allow toxic fracing fluids to seep into soil and contaminate groundwater.

As mentioned previously, hydraulic fracturing is used in many coalbed methane (CBM) production areas. Some coal beds contain groundwater of high enough quality to be considered ***underground sources of drinking water*** (USDWs). According to the U.S. Environmental Protection Agency (EPA) ten out of eleven CBM basins in the U.S. are located, at least in part, within USDWs. Furthermore, EPA has determined that in some cases, hydraulic fracturing chemicals are injected directly into USDWs during the course of normal fracturing operations.[91]

Calculations performed by EPA show that at least nine hydraulic fracturing chemicals may be injected into or close to USDWs at concentrations that pose a threat to human health. These chemicals may be injected at concentrations that are anywhere from 4 to almost 13,000 times the acceptable concentration in drinking water.[92] (See Peggy Hocutt's letter and Laura Amos' story in Chapter IV, to read landowner stories about how hydraulic fracturing of coalbeds and other geological formations has affected drinking water.)

Not only does the injection of these chemicals pose a short-term threat to drinking water quality, it is quite possible that there could be long-term negative consequences for USDWs from these fracturing fluids. According to the EPA study, and studies conducted by the oil and gas industry,[93] between 20 and 40% of the fracturing fluids may remain in the formation, which means the fluids could continue to be a source of groundwater contamination for years to come.

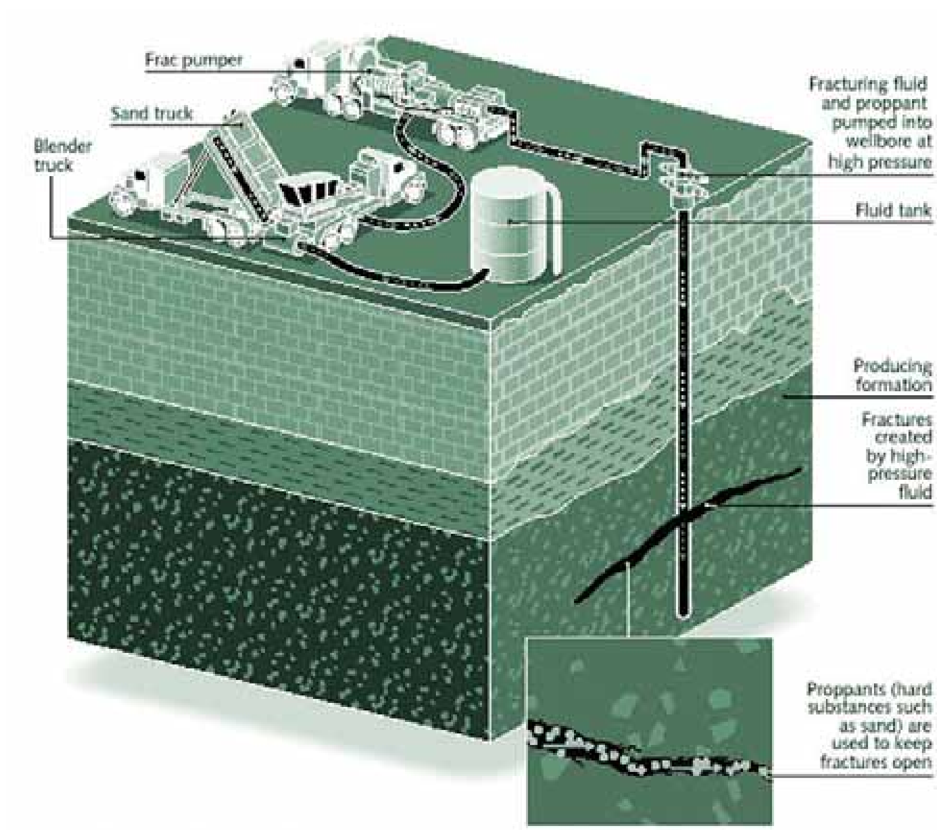
The potential long-term consequences of dewatering and hydraulic fracturing on water resources have been summed up by professional hydrogeologist who spent 32 years with the U.S. Geological Survey:

> *At greatest risk of contamination are the coalbed aquifers currently used as sources of drinking water. For example, in the Powder River Basin (PRB) the coalbeds are the best aquifers. CBM production in the PRB will destroy most of these water wells; BLM predicts drawdowns...that will render the water wells in the coal unusable because the water levels will drop 600 to 800 feet. The CBM production in the PRB is predicted to be largely over by the year 2020. By the year 2060 water levels in the coalbeds are predicted to have recovered to within 95% of their current levels; the coalbeds will again become useful aquifers. However, contamination associated with hydrofracturing in the basin could threaten the usefulness of the aquifers for future use.*[94]

One potentially frustrating issue for surface owners is that it may not be easy to find out what chemicals are being used during the hydraulic fracturing operations in your neighborhood. According to the Natural Resources Defense Council, attempts by various environmental and ranching advocacy organizations to obtain chemical compositions of hydraulic fracturing fluids have not been successful because oil and gas companies refuse to reveal this "proprietary information."[95]

As mentioned above, anywhere from 20-40% of fracing fluids remain in the ground. Some fracturing gels remain stranded in the formation, even when companies have tried to flush out the gels using water and strong acids.[96] Also, studies show that gelling agents in hydraulic fracturing fluids decrease the permeability of coals, which is the opposite of what hydraulic fracturing is supposed to do (i.e., increase the permeability of the coal formations). Other similar, unwanted side effects from water- and chemical-based fracturing include: solids plugging up the cracks; water retention in the formation; and chemical reactions between the formation minerals and stimulation fluids. All of these cause a reduction in the permeability in the geological formations.[97]

From a public health perspective, if hydraulic fracturing stimulation takes place, the best option is to fracture formations using sand and water without any additives, or sand and water with non-toxic additives. Non-toxic additives are being used by the offshore oil and gas industry, which has had to develop fracturing fluids that are non-toxic to marine organisms.[98]



High-pressure fluid creates cracks extending 300 metres (990 feet) or more into the producing formation. Sand props open the cracks, which are typically five to ten metres high but only two to six millimetres wide (0.078 to 0.236 inches).

FIGURE I-11. DIAGRAM OF HYDRAULIC FRACTURING OPERATION.

Source: Petroleum Communication Foundation. (Canadian Centre for Energy Information). 1999.[99]

It is common to use diesel in hydraulic fracturing fluids. This should be avoided, since diesel contains the carcinogen benzene, as well as other harmful chemicals such as naphthalene, toluene, ethylbenzene and xylene. According to the company Halliburton, "Diesel does not enhance the efficiency of the fracturing fluid; it is merely a component of the delivery system."[100] It is technologically feasible to replace diesel with non-toxic "delivery systems," such as plain water. According to the EPA, "Water-based alternatives exist and from an environmental perspective, these water-based products are preferable."[101]

Stimulation—Tip for Landowners

The law requires that all employees have access to a Material Safety Data Sheet (MSDS), which contains information on health hazards, chemical ingredients, physical characteristics, control measures, and special handling procedures for all hazardous substances in the work area. The MSDSs are produced and distributed by the chemical manufacturers and distributors. It should be noted that MSDSs may not list all of the chemicals or chemical constituents being used (if they are trade secrets).[102] Landowners may be able to obtain copies of MSDSs from company employees, the chemical manufacturers, or possibly from state agency representatives.

For more information on impacts associated with hydraulic fracturing, and alternative fracturing techniques, please visit the Oil and Gas Accountability web site: http://www.ogap.org .

Well Testing

After the well has been drilled, and before production begins, the reservoir pressure is tested. Prior to testing, however, large volumes of debris, fluids and gases must be cleaned out of the well bore. For example, any fluid, rock debris and sand remaining in the well bore and surrounding reservoir from stimulation activities (e.g., cavitation or hydraulic fracturing) has to be cleaned out. The conventional method for doing this is to pump air down the well bore to lift the sand and fracturing fluid up and out.[103] These wastes are usually dumped into earthen pits.

Natural gas is mixed in with the air, sand and liquids exiting the well bore. These gases are either "blown off" (i.e., vented to the atmosphere) or "burned off" (i.e., flared).

During the well test, the gas in a newly drilled well is allowed to flow freely for a number of days while the rate-of-flow and pressure of the gas in the reservoir are measured. According to the Pembina Institute for Appropriate Development, "a company can normally get enough data in one to three days, [therefore] well testing should be minimized and not exceed three days, especially when there is flaring or direct venting to the atmosphere."[104]

Well Testing—Tips for Landowners

- To minimize potential environmental impacts from the storage of solid and liquid wastes that flow from the well, "flowback units" rather than earthen pits should be used. Also, "flareless completions" or "green completion" techniques can be used to minimize the air pollution from the venting or flaring of natural gas during the well clean-up and testing phases.
- For more information on both of these technologies, see the section on Alternative Technologies and Practices, later in this chapter.

Oil and Gas Treatment and Conditioning

The fluids that flow or are pumped to the surface from conventional oil or gas wells include a mixture of oil, water, various gases and dissolved and suspended solids.[105] Before oil and natural gas can be marketed, the fluids must go through a ***treatment*** process to separate out water and remove dangerous gases and other impurities. Some of the treatment can occur at the well site (***field processing***). After initial treatment, however, the crude oil or natural gas is sent through a pipeline to a centralized processing facility such as an oil battery or a gas plant.

Gathering is the movement of bulk oil or gas from a production well to the treatment facility.

Below is a general overview of some of the processes involved in preparing the oil and gas for sale.

If crude oil is being recovered: Some separation of associated natural gas from the raw crude oil may occur at the wellhead. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas. The natural gas may be captured and sold, but often it is simply flared or vented to the atmosphere. Flowlines or gathering lines move the raw crude oil to an oil battery, for additional conditioning before sending the oil to a refinery. At the oil battery, the fluids pass through a production separator, which separates gases from the oil and water. The oil and water then go to a heater treater, where the oil is separated from the water and any solids that are present. The crude oil is at least 98% free of solids after it passes through this treatment.[106] The oil is then piped to a storage facility, where it remains until it is transported offsite by either trucks or by pipeline.

If a gas pipeline or gas transportation vehicles are present, the gases may be transported to a gas plant for processing into products such as methane, ethane, propane, and butane. Alternatively, the gases may be treated as a waste product, and be vented or flared.[107] The water and solids removed may be piped to a pit, a tank, or into a flowline leading to an underground disposal well.[108]

FIGURE I-12. NATURAL GAS DEHYDRATOR. Source of benzene.

If natural gas is being recovered: Natural gas conditioning methods will be used to remove impurities from the gas so that it meets the quality required to be accepted by gas transportation systems. This is not always necessary, as some natural gas is pure enough to pass directly into the pipeline. Often, the most significant impurity is hydrogen sulfide (H_2S). Other impurities that may have to be removed include: water vapor, natural gas liquids, sand, nitrogen, and aromatic compounds such as benzene, toluene, ethylbenzene, and xylene.

Sweetening removes H_2S from the gas. The most common method of sweetening involves exposing the gas to an amine solution, which reacts with H_2S and separates it from the natural gas. The H_2S may be disposed of by flaring, incineration, or, if a market exists, by sending it to a sulfur-recovery facility. Another sweetening method uses an iron sponge, which reacts with H_2S to form iron sulfide. The iron sulfide is oxidized, then buried or incinerated.[109]

Dehydration removes water from the gas. The most common dehydration method used at the wellhead is glycol dehydration. In this method, gas is exposed to glycol, which absorbs the water. The water can be evaporated from the glycol so that the glycol can be reused. If the gas is sent to a natural gas plant for processing, solid desiccants are more commonly used to remove the water. Solid desiccants are crystals that have large surface areas that attract water molecules. Like glycol, these desiccants can be reused after water has been removed from them. If gas is extracted from deep, hot wells, simply cooling the gas to a low enough temperature can remove enough water to allow it to be transported.[110]

FIGURE I-13. GAS PROCESSING PLANT. Source of NO_X.

Photo by Dan Randolph

FIGURE I-14. WELLHEAD COMPRESSORS
With and without sound abatement.

FIGURE I-15. COMPRESSOR STATION Source of NO_X.

FIGURE I-16. SEPARATOR AND STORAGE TANK FOR THE SEPARATED LIQUIDS

Natural gas coming directly from a well contains many natural gas liquids (NGLs), e.g., ethane, propane, butane, iso-butane, and natural gasoline. NGLs often have a higher value when sold as separate products, making it economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.[111]

In addition to the processes mentioned above, scrubbers and heaters are installed either at or near the wellhead. The scrubbers remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low and form natural gas ***hydrates***, which are solid or semi-solid compounds that resemble ice crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems. In addition to wellhead heaters, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.[112]

While some of the processing can be accomplished at or near the wellhead, the complete processing of natural gas takes place at a processing plant. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. Some gathering systems are quite complex, consisting of thousands of miles of pipes that connect the processing plant to as many as 100 wells in the area. Should natural gas from a particular well have high sulfur and carbon dioxide contents, a specialized sour gas gathering pipe must be installed.

If the natural gas is being piped into larger pipelines, such as interstate pipelines, it must be compressed. To ensure that the natural gas flowing through any one pipeline remains pressurized, compressor stations are usually placed at 40-100-mile intervals along the pipeline. The natural gas enters the compressor station, where it is compressed by a gas-powered turbine, electric motor, or gas powered engine.

It is not uncommon for a certain amount of water and hydrocarbons to condense out of the gas stream while in transit. Thus, in addition to compressing natural gas, compressor stations often contain a liquid separator that has scrubbers and filters to remove liquids or other undesirable particles from the natural gas in the pipeline.

In some regions, such as the Appalachian states, natural gas might not require sweetening or extensive dehydration. Therefore, the gas may be piped directly from the wellhead to a main transmission line and, in some cases, directly to the customer. Compressor stations are located as needed along the pipelines that run between the wellhead and the main transmission line or the customer to maintain pressure in the lines.[113]

Compressors vary in size. Some compressors serve an individual well (wellhead compressors); others may serve a number of wells.

Production Enhancement

A variety of techniques are used to enhance the flow of oil or gas during operations. Some of these techniques are the same ones used to stimulate flow during well completion, e.g., hydraulic fracturing and acidizing.

For enhancement of oil production, a common technique is known as waterflooding. This technique enhances oil recovery by injecting water to build up the pressure in the reservoir, thus, forcing more oil into the well.

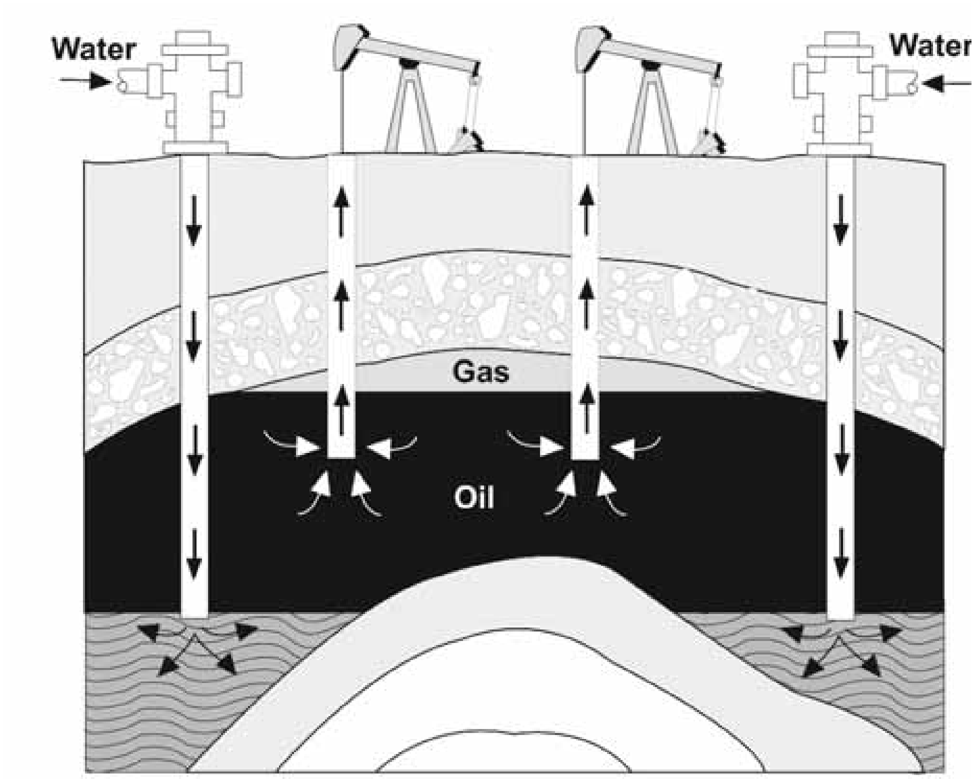


FIGURE I-17. OIL PRODUCTION ENHANCEMENT USING THE WATERFLOODING TECHNIQUE.
Source: Energy Information Administration, Department of Energy, 1991.[114]

Often, produced water is used for the waterflooding operation. Produced water should be thoroughly treated before injection so that it is free of solids, bacteria, and oxygen, all of which could contaminate the oil reservoir and, in the case of sulfur-reducing bacteria, could lead to increased hydrogen sulfide concentrations in the extracted oil.[115]

Other methods of enhancement may be used, but are often more expensive and energy intensive than waterflooding. Examples include:[116]

- Thermal recovery, where the reservoir fluid is heated through the injection of steam or by controlled burning within the reservoir. Heating makes the fluid less viscous and more conducive to flow. This technique is used to stimulate the flow of heavy oils from oil shales and tar sands.
- The injection of carbon dioxide or alcohol, which reduce oil density, allowing the oil to rise to the surface more easily.
- The injection of surfactants, which are substances that essentially wash the oil from the reservoir.
- Microbial enhanced recovery, where oxygen and microbes capable of digesting heavy oil and asphalt are injected into the formation, freeing up the lighter oil to flow to the surface.

Maintenance Procedures

Production wells require ongoing maintenance, such as replacing worn or malfunctioning equipment and painting and cleaning the equipment. Periodically,oil and gas operations require significant maintenance, called workovers. During a workover several tasks may be undertaken such as: repairing leaks in the casing or tubing; stimulating the well; perforating a different section of casing to produce from a different formation in the well; applying corrosion-prevention compounds; and removing accumulated salts (scale) and paraffin from production tubing, gathering lines, and valves.

Oil and Gas Processing, Refining and Transportation

There are a host of issues related to large oil and natural gas processing facilities, refineries and pipelines. It is beyond the scope of this guide to go into detail on all of the issues related to oil or gas once it leaves a surface owner's property. For more information, refer to the resources in Chapter V.

FIGURE I-18. SURFACE DISTURBANCE CREATED BY PIPELINE CORRIDORS

PRODUCTION STAGE—ISSUES AND IMPACTS

Surface Disturbance

- Additional land disturbance may occur as a result of the construction of production facilities and infrastructure such as compressors, pipelines, etc.
- Reclamation of areas disturbed during the drilling process should be conducted during the production stage. This is known as ***interim reclamation***.

Air Pollution

There are a number of pollutants that are associated with the production stage. These include volatile organic compounds (VOCs), nitrogen oxides, sulfur dioxide, carbon monoxide, benzene, toluene, ethylbenzene, xylene, polycyclic aromatic hydrocarbons, hydrogen sulfide, particulate matter, ozone and methane. For more information on these air emissions, read about Impacts Associated with Oil and Gas Operations.

FIGURE I-19. VENTING OF GAS WELL
Source of methane, a greenhouse gas.

In 2001, the oil and gas industry in the U.S. vented and flared about 86 billion cubic feet of gas.[117] Not only do venting and flaring waste natural gas (which should be a concern for mineral owner who would have received royalties on the gas), these emissions also contribute to air pollution and greenhouse gases in the atmosphere.

Venting of natural gas may occur during:

- Well testing.
- Oil and gas processing. Solution gases from oil wells, batteries or tanks, and natural gas from compressor vents, instrument gas stations, pneumatic devices, dehydrators and storage tanks may be intentionally or unintentionally released.
- Pipeline maintenance operations. Prior to any work on a pipeline, gases in the line are purged and may be vented directly to the atmosphere.

FIGURE I-20. FLARING DURING COMPLETION OF A COALBED METHANE WELL.
Photo by OGAP.

Flaring of natural gas may occur during:

- Well testing.
- Cavitation and hydraulic fracturing (see flareless completions in the section on Alternative Technologies and Practices later in this chapter)
- Oil processing. It occurs at batteries where oil is processed and stored. These flares burn constantly, because gas is a by-product of oil production. Known as solution gas, this gas is the largest source of flaring in Alberta, Canada.[118]
- Gas processing. At processing plants, gas by-products that have no market are burned off. Gas may also be flared during emergency situations.
- Pipeline maintenance operations. Prior to work on a pipeline, gases in the line are purged and may be flared.

It has been argued that flaring is better than allowing the gases to be vented directly into the atmosphere because of the health threats posed by some of these substances (e.g., H_2S). While it is true that flaring can greatly reduce the concentrations of H_2S that would otherwise be vented to the atmosphere, it must be noted that flaring still allows low levels of that compound to be emitted. Moreover, it has been demonstrated that only 66-84% of flared gases are fully combusted.[119] Research has shown that incomplete combustion from flaring releases as many as 250 hazardous air pollutants that include: nitrogen oxides, sulfur dioxide, benzene, toluene, ethylbenzene and xylene, polycyclic aromatic hydrocarbons (PAHs) and, in the case of sour gas, hydrogen sulfide and carbon disulfide. Some of these, such as benzene and some PAHs are cancer-causing, while others (e.g., toluene, ethyl benzene, xylenes) are also known to affect human health (e.g., reproduction, respiratory systems).[120]

Emissions from flaring, especially during well testing, can result in high ground-level concentrations of pollutants. Depending on the levels, these substances may affect the health of humans and other animals and vegetation. For more information on air pollution from flaring, read about Impacts Associated with Oil and Gas Operations, in this chapter, and landowner stories in Chapter IV.

The following alternative practices may be used to reduce venting and flaring:[121]

- Well testing: In some cases, the need for well test flaring may be eliminated by conducting in-line testing through a pipeline to a processing facility. If, however, test flaring cannot be avoided, the use of improved well-logging instrumentation, and the use of existing reservoir data from previous well tests should be able to significantly shorten the duration of the test.
- Gas Processing: Gases that would be flared can be piped to microturbines, to generate electricity for local use. Or, the gas can be injected deep into the ground, where it will not come in contact with fresh water aquifers.
- Pipeline maintenance: If more valves are installed on the pipeline, a smaller section will have to be purged to perform the maintenance activities, which reduce the releases to the atmosphere.
- Decreasing emissions of hazardous compounds: If more efficient burners or incinerators on flare stacks are installed, there will be more complete combustion, and fewer pollutants emitted to the atmosphere.

If the regulations regarding flaring and venting are not very stringent in your state, you may want to negotiate with the companies to establish large setbacks from the well to your home. If your home is in a low-lying area, setbacks may not fully protect you from the harmful emissions, since airborne substances like hydrogen sulfide can settle in depressions in the landscape. Furthermore, setbacks may not protect livestock or wildlife in the area. Consequently, you should push hard to get companies to adopt alternative practices and minimize flaring and venting from their operations.

Noise

Landowners often complain about noise levels associated with natural gas compressors. The noise level varies with the size of the compressor and distance from the compressor; and it changes with shifts in wind direction and intensity. According to the Powder River Basin Resource Council, "Depending on the wind direction, the roar of a field compressor can be heard three to four miles from the site. Near the compressor stations, people need to shout to make themselves heard over the sound of the engines."[122]

For more information on the impact of noise on landowners, read about Impacts Associated with Oil and Gas Operations, and landowner stories in Chapter IV.

Water Use

- Typically, hundreds of thousands of gallons of water are required to drill and complete a conventional well.[123]
- Large quantities of water may (50,000 to millions of gallons) be used to stimulate or enhance

production from oil and gas wells. This water may be fresh, or companies may re-use produced water from their operations.

Wastes

Associated wastes are wastes other than drilling wastes and produced water. Examples are:

- Wastes associated with flowing wells, which include paraffin, slop oil, scale, treating chemicals, sand and paint.[124]
- Wastes associated with pumped wells, which include used lubrication oil and filters, gas lift engine fuel, released crude oil, paraffin, slop oil, scale, treating chemicals, sand, and paint.[125]
- Wastes associated with maintenance operations, which include chemicals used to remove scale (highly concentrated hydrochloric and hydrofluoric acids, organic acids, and phosphates); corrosion inhibitors (ammonium bisulfite, zinc); paint solvents; cleaning solvents; and workover fluid, which is similar to drilling fluid.[126] These compounds usually end up in produced water, after production resumes. Any acids should be neutralized before produced water is discharged to watercourses.
- Other associated wastes include trace contaminants such as barium, strontium, and radium associated with scale that is removed during maintenance; volatile organic compounds (VOCs), which are air pollutants; and high concentrations of salts and metals.[127]
- The American Petroleum Institute estimated that in 1995, the annual volume of associated wastes was 22 millions barrels.[128] The majority of associated wastes produced at conventional oil and gas sites are disposed of through injection wells.[129]

Produced water may accompany the oil and gas when pumping is necessary to bring oil and natural gas to the surface. It is also produced during coalbed methane extraction.

- Produced water is the largest volume waste generated in oil and gas extraction operations.[130] Typically, about 3 barrels of produced water are pumped for each barrel of oil.[131] Natural gas wells produce much less water than do oil wells, with the exception of certain types of gas resources such as coalbed methane or Devonian/Antrim shales.[132] It is estimated that the United States oil and gas industry generates 20 to 30 billion barrels of produced water every year.[133]
- The water produced with conventional oil or gas operations is generally unsuitable for most domestic or agricultural purposes, either because it is extremely salty or due to the presence of toxic or radioactive compounds.
- It is important that produced water be disposed of properly, since it may contain a variety of contaminants such as benzene, phenols, toluene and xylene, salts, metals and naturally occurring radioactive materials (NORM).[134]
- For more information about produced water, see Impacts Associated with Oil and Gas Operations, below.

Produced sand consists of sands and other particles generated during production, including those used in hydraulic fracturing. Other solid wastes include sludge remaining after various chemicals are removed during produced water treatment. Produced sand typically contains crude oil, which can comprise as much as 19 % by volume. Depending upon the location, produced sand may also contain naturally occurring radioactive material (NORM),[135] which is discussed in more detail below.

Spills of oil may come from leaking tanks, leaking flowlines, valves, joints, or gauges.[136] Other chemicals used during the production stage (e.g., solvents, workover fluids) may be spilled due to human error. Spilled oil and chemicals may contaminate soils, groundwater and surface watercourses.

Waste Management

- Open pits used to store wastes pose a health threat to livestock and wildlife. The wastes often contain hydrocarbons, and seepages from waste pits may contaminate soils, groundwater and surface watercourses. If open pits are used, they should be lined, with a leak detection system, to prevent seepages. And the pits should be fenced-in, and nets or other devices installed to prevent birds and wildlife from coming in contact with the wastes.
- In Wyoming, citizen complaints forced the U.S. Environmental Protection Agency to conduct studies into potential contamination of their drinking water wells. Studies revealed that wastes from an oil field service area and an unlined waste pond at a natural gas processing facility had seeped into the ground and contaminated the drinking water wells with volatile halogenated hydrocarbons. The site was declared a Superfund site in 1990. Residents were provided with alternative sources of drinking water (they were hooked up to the nearest municipal drinking water system), and the companies involved were required to remove and treat the soil, and pump and treat the contaminated groundwater.[137]

FIGURE I-21. TORN LINER ON AN OPEN PIT.

- Many materials used during maintenance procedures, such as solvents used for cleaning, are classified as hazardous wastes after they are used. Non-hazardous alternatives, which are safer for the environment and present fewer regulatory concerns for the company, are available. Substitutes include: citrus-based cleaning compounds or steam instead of hazardous solvents; a high flash point Varsol to replace the solvent Varsol (also called petroleum spirits or Stoddard solvent) to reduce this solvent's ignitability hazardous waste characteristic; and water-based paints instead of solvent-based paints, which reduces or eliminates the need for solvents and thinners.[138]

4. SITE ABANDONMENT

When a well is no longer economic to operate, it is abandoned. When an oil or gas well is abandoned it should be plugged or converted into an injection well, and the site should be reclaimed.

Sometimes a well will appear to be abandoned when in reality it is simply experiencing a temporary halt in production. For temporary work stoppages, the well will be shut in, which is accomplished by closing the valves at the wellhead. During this period, the well is considered to be idle. Wells may be idle for a few days, for example, to conduct well workovers or install new pipeline connections; or wells may be idle for a much longer duration, for example, if there is a downturn in the global market for oil or gas. If production is still technically viable, it is much more desirable to shut in a well rather than plug it because once the well is permanently plugged and abandoned it is highly impractical to re-access any remaining oil or gas in the reservoir.[139]

Plugging Wells

Before a company permanently leaves a well site, the well should be plugged or capped. The purpose of plugging is to prevent formation water from migrating into and contaminating aquifers or surface water.

All oil and gas producing states have specific regulations governing the plugging and abandonment of wells.[140] Generally, however, when a well is plugged there are a number of steps that are taken. First, the downhole equipment is removed and the perforated sections of the well bore are cleaned of scale and other wastes. Then, a minimum of three cement plugs, each between 100-200 feet in length, are placed into the well. Plugs should be placed: 1) into the perforated zones of the well, in order to prevent the inflow of fluid; 2) in the middle of the wellbore; and 3) within a couple hundred feet of the surface. Also, fluid with an appropriate density is placed between the cement plugs in order to maintain adequate pressure in the voids. Finally, the casing is cut off below the surface and capped with a steel plate welded to the casing. Surface reclamation should then be undertaken to restore natural soil consistency and plant cover.

FIGURE I-22. LEFT-RIGHT: PLUGGED WELL, NOT RECLAIMED. PLUGGED WELL, RECLAIMED. Photo at right used with permission of Vermejo Park Ranches.

Conversion to an Injection Well

If the well is located in an area where a company has many nearby wells still in production, the company may decide to convert the well to an injection well. If this occurs, the well will be regulated by the federal government as an *Underground Injection Control (UIC) Class II Injection well*, and will be subject to the federal *Safe Drinking Water Act and Underground Injection Control Regulations*.[141] Such a well can be used either for disposal of the produced water from other wells, or as part of oil enhancement operations in the production field.

Reclamation

Federal, state, and sometimes local rules and regulations describe how reclamation is supposed to occur when a site is abandoned. In some states, companies are required to provide financial assurance (e.g., bonds) to ensure that some funds are available to plug the wells and carry out the reclamation activities. Reclamation clauses in surface use agreements negotiated during the early stages also come into play at this stage.

Full reclamation should leave the land, air and water in the same condition as before oil and gas development was carried out. This is rarely the case. In many states, the unwillingness of companies to completely restore the original environment is accepted by state governments. Consequently, operators are required only to reclaim the land "as nearly as is possible" to it pre-development condition.

Reclamation activities typically include: removal of all well-related equipment; re-grading of roads and other surfaces; removal of trash and debris; road closures; closure and remediation of pits and contaminated soils; and site revegetation. While this stage appears at the end of the development process, there are interim reclamation activities that can and often must be performed by operators at other stages of development. An example of interim or "annual" reclamation requirements can be found in the Vermejo Park Ranch Mineral Extraction Agreement in Chapter III.

SITE ABANDONMENT—ISSUES AND IMPACTS

Orphaned and Idle Wells

Surface owners should be aware that as a well becomes less and less profitable, some larger companies will sell these wells to smaller companies. Eventually, these wells may become the responsibility of the state, for example, if the smaller company does not have the funding to properly plug the wells and reclaim the site. If a company goes bankrupt and has no assets available to be used for proper well abandonment the well is considered to be an ***orphan well***.[142] The term orphan well also applies to the situation where the operator is unknown (e.g., in the case of wells drilled in the early part of the century).

Idle wells are wells that have ceased production but have not been plugged. In most states, wells require regulatory approval to be idle.[143] Most states allow some period of time of inactivity (usually six months to one year) without approval. When this initial time has elapsed, states may require a statement of the operator's intentions, which may include extensive geological and engineering information and a schedule for returning the well to production.[144] Also, a state may require periodical mechanical integrity tests to ensure that the well does not pose a threat to the environment.[145]

- In 1995, there were 134,000 wells in the U.S. that had stopped production yet had neither been plugged nor received government approval to be idle.[146]
- Orphan wells and idle wells that do not have government approval may present a groundwater contamination hazard. With many of these wells, the integrity of the casing is not known, and so there is a possibility that reservoir fluids or gases are contaminating or will contaminate nearby fresh water aquifers. Not all wells will cause contamination, but until the wells are evaluated, the risk that they pose is unknown.
- Most oil- and gas-producing states have a program for addressing orphan wells, which includes: prioritizing wells (because states do not have the funding to assess and properly plug all orphan wells); programs to plug dangerous orphan wells; and clean up of any contamination that may have already occurred.
- There is no guarantee that a state will have adequate funding to properly plug and reclaim orphan sites; leaving the surface owner with concerns about long-term risk of contamination. See "Bankrupt companies walk away from oil wells in Texas," Chapter II.
- One source of information that can help inform state regulators of the risks posed by orphan or idle wells comes from area of review (AOR) studies that are required for the approval of new underground injection wells. Under this requirement, the operator of the new well must study all active, idle and abandoned wells within an area (often a ¼ mile radius) to determine whether they pose a risk of contamination.[147]

Improperly Plugged and Abandoned Wells

- Improperly completed and abandoned wells may allow contaminants such as pesticides to be transferred from the surface to groundwater.

- Oil, gas, and salt water can leak from abandoned, unplugged, or improperly plugged oil and gas wells, especially older wells, and pollute groundwater resources,[148] or migrate to the surface. In Colorado, Oil and Gas Conservation Commission (COGCC) staff believe that increased methane concentrations found in water wells and buildings in some areas are partially due to old, improperly abandoned gas wells and older, deeper conventional gas wells that were not completely isolated. According to COGCC officials, a mitigation program focused on sealing old, improperly abandoned gas wells appears to have reduced methane concentrations in approximately 27 percent of the water wells sampled.[149]
- Additionally, improperly closed sites can be a safety hazard to humans and livestock.

Tips for Landowners

- Surface owners should work with state agencies to ensure that abandonment is satisfactorily completed.
- Owners may want to consider pressuring companies to use native species in their re-seeding projects, as these may be better able to combat noxious weed species.
- The company should have saved topsoil during the drilling and production stages for use in their reclamation efforts.
- Almost all states require companies to set aside funds to properly plug and abandon their wells. There is more information on financial assurance (or bonding) in Chapter II.

Ideally, full reclamation should leave vegetation, soil, air and water in the same condition that existed prior to oil and gas development. This rarely occurs.

Development of Nonconventional Gas and Oil

Forward-thinking landowners may want to investigate the possibility of unconventional reservoirs beneath their land, since it is likely that more non-conventional oil and gas deposits will be developed in the near future. This is certainly happening with the nonconventional coalbed methane gas deposits.

Nonconventional gas includes gas trapped in coal formations (***coalbed methane***); and low-permeability sandstone (***tight sands***) and shale formations (***gas shales***). These three types of natural gas are currently being exploited in some areas of the U.S., and will be discussed in this section. Other nonconventional natural gas resources, such as gas hydrates, are not likely to become commercially viable for decades to come.[150] Consequently, they will not be discussed in this guide.

Nonconventional oil deposits include ***heavy oils***, ***tar sands*** and ***oil shales***. As mentioned previously, petroleum is a broad term for hydrocarbons that includes gases, highly fluid "light" oils, viscous "heavy" oils, tars and bitumens. Today, light oils comprise approximately 95 % of petroleum production.[151] As will be discussed later in this section, when compared to conventional deposits and methods, the amount of work required to produce an equivalent amount of crude oil from tar sands or oil shales makes it cost prohibitive under most circumstances.[152]

COALBED METHANE (CBM)

As many landowners in Wyoming, Montana, Colorado, New Mexico and Alabama can attest, an increasingly significant source of natural gas is coalbed methane (see the Introduction chapter for a map of CBM producing areas). Two decades ago, coalbed methane was not a highly profitable source of natural gas. By the year 2004, however, CBM accounted for more than 8% of natural gas production in the U.S.[153]

According to the CBM Association of Alabama, 13% of the land in the lower 48 United States has some coal under it, and in all coal deposits methane is found as a byproduct of the coal formation process. Historically, this methane was considered a safety hazard in the coal mining process and was purposely vented to the atmosphere. Recently, however, companies have begun to capture the methane found in coal mines, as well as recover methane from coalbed deposits that are too deep to mine.[154]

Coal beds are an attractive prospect for development because of their ability to retain large amounts of gas—coal is able to store six to seven times more gas than an equivalent volume of rock common to conventional gas reservoirs.[155] On a daily basis, however, CBM wells typically do not produce as much gas as conventional wells.[156] In most regions of the U.S., coalbed methane wells produce between 100 and 500 thousand cubic feet (Mcf) per day, while the average conventional well in the lower 48 states produces approximately 1.7 million cubic feet (MMcf) per day.[157] There are, however, some extremely productive coalbed methane areas, such as the San Juan basin in Colorado and New Mexico, where some wells produce up to 3 MMcf of methane per day.[158]

The amount of methane in a coal deposit depends on the quality and depth of the deposit. In general, the higher the energy value of the coal[159] and the deeper the coal bed, the more methane in the deposit.[160]

Methane is loosely bound to coal—held in place by the water in the coal deposits. The water contributes pressure that keeps methane gas attached to the coal. In CBM development, water is removed from the coal bed (by pumping), which decreases the pressure on the gas and allows it to detach from the coal and flow up the well.

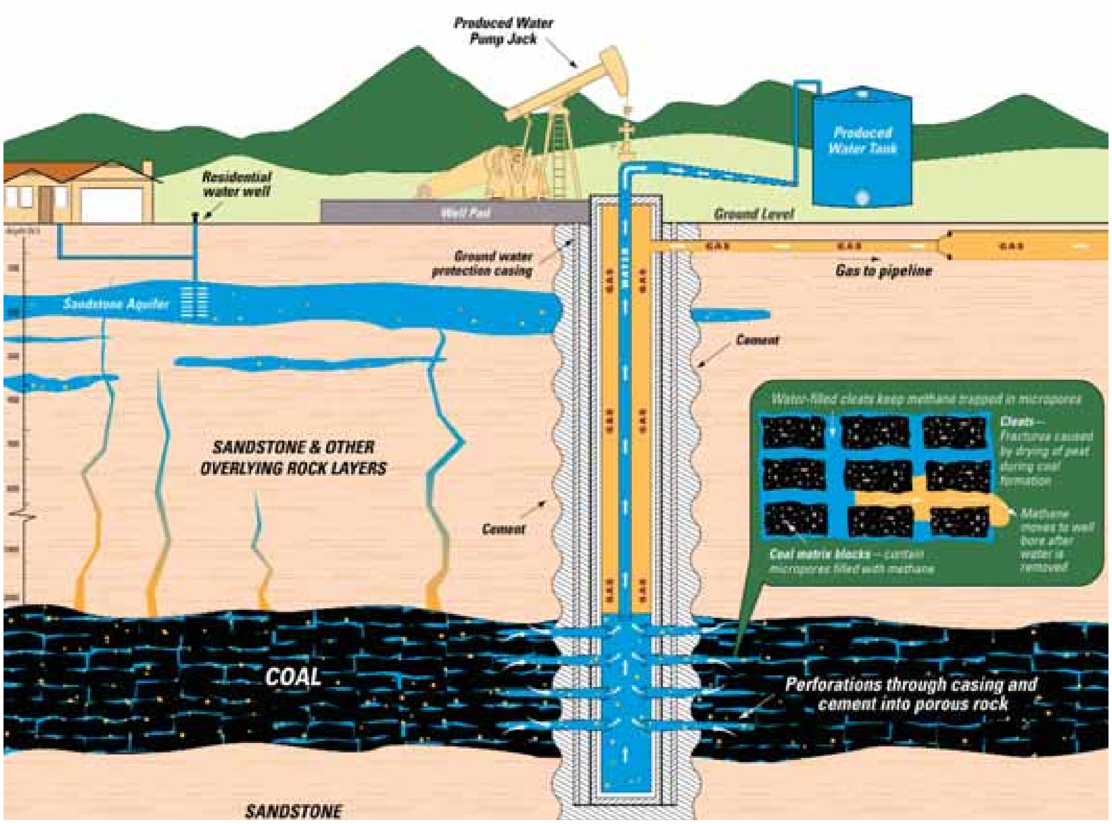


FIGURE I-24. TYPICAL COALBED METHANE WELL. Source: Ecos Consulting.

In the initial production stage of coalbed methane, the wells produce mostly water. Eventually, as the coal beds near the pumping well are dewatered, the volume of pumped water decreases and the production of gas increases.[161] Depending on the geological conditions, it may take several years to achieve full-scale gas production. Generally, the deeper the coal bed the less water present, and the sooner the well will begin to produce gas.

Water removed from coal beds is known as produced water. The amount of water produced from most CBM wells is relatively high compared to conventional gas wells because coal beds contain many fractures and pores that can contain and move large volumes of water.[162]

CBM wells are drilled with techniques similar to those used for conventional wells. In some regions where the coal beds are shallow, smaller, less expensive rigs, such as modified water-well drilling rigs, can be used to drill CBM wells, rather than the more expensive, specialized oil and gas drilling rigs.[163]

As with conventional gas wells, hydraulic fracturing is used as a primary means of stimulating gas flow in CBM wells.[164] Another gas stimulation technique, unique to CBM wells, is known as ***cavitation*** (also known as open-hole cavity completion).

Cavitation is a similar phenomenon to opening a shaken pop bottle, only on a much larger scale.[165] Water, and air or foam are pumped into the well to increase the pressure in the reservoir. Shortly thereafter, the pressure is suddenly released, and the well violently blows out, spewing gas, water, coal and rock fragments out of the well. This action is sometimes referred to as "surging," and it is accompanied by a jet engine-like noise, which can last up to 15 minutes.[166]

The coal fragments and gas that escape from the well are directed at an earthen berm, which is supposed to prevent the materials from entering the greater environment. The gas is burned or flared, and the coal fines and fluids initially collect in a pit at the base of the berm. Some loose rock and coal materials remain in the well. They are cleaned out by circulating water (and often a soap solution or surfactant) within the well and pumping the material into a pit. The coal refuse is then typically burned on-site in a pit, which is either referred to as a "burn pit" or "blooie pit." (See Figure I-25.)

The cavitation process is repeated several dozen times over a 2-week period.[167] This results in an enlargement of the initially drilled hole (well bore) by as much as 16 feet in diameter in the coal zone, as well as fractures that extend from the well bore.[168] If the cavitation fractures connect to natural fractures in the coal, they provide channels for gas to more easily flow to the well.

At the present time, cavitation is not widely practiced. The U.S. Department of Energy reported that in 2000, the only "cavity fairway" in the United States was located in the central San Juan Basin, in Colorado and New Mexico.[169]

FIGURE I-25. CAVITATION BURN PIT.

COALBED METHANE—ISSUES AND IMPACTS

Produced Water

Produced water quality varies depending primarily upon the geology of the coal formation. Typically, saltier water is produced from deeper coal formations. Produced water may contain nitrate, nitrite, chlorides, other salts, benzene, toluene, ethylbenzene, other minerals, metals and high levels of total dissolved solids.[170]

Depending on which state you live in, produced water may be: discharged onto land, spread onto roads, discharged into evaporation/percolation pits, reinjected into aquifers, discharged into existing water courses (with the proper permit), or disposed of in commercial facilities. In some states, standards for produced water disposal are becoming more rigorous, and certain disposal practices are losing favor. Surface discharge, for example, is a controversial method of disposal, as it can lead to a build-up of salts and other substances in the soil, and affect the productivity of the land. In some states, re-injection is the only option for disposal.[171] See section on Impacts Associated with Oil and Gas Operations for more information on produced water disposal options.

In some areas, coal beds may be important local or regional aquifers (natural underground water storage zones), and important sources for drinking water.[172] It is important, therefore, that landowners find out how companies are planning on disposing of produced water, and what impact its removal and disposal might have on water supplies.

Water Quality and Methane/Hydrogen Sulfide Migration

A study conducted by the US Environmental Protection Agency (EPA) documents a number of examples of water quality impacts and other issues encountered after CBM extraction occurred.[173] These include reported incidents of:

- Explosive levels of hydrogen sulfide and methane under buildings and inside homes
- Death of vegetation (possibly due to seepage of methane and decreased air in root zones)
- Increased concentrations of methane and hydrogen sulfide in domestic water wells
- Cloudy well water with increased sediment concentrations following hydraulic fracturing
- Strong odors and black coal fines in water wells
- Brown, slimy well water that smelled like petroleum
- Decrease in well water levels and surface water flows following hydraulic fracturing
- The discharge of produced water creating new ponds and swamps that were not naturally occurring in particular regions

A decline in water quality may be created by hydraulic fracturing fluids. The EPA has stated that

> *"if coalbeds are located within underground sources of drinking water (USDW), then any fracturing fluids injected into coalbeds have the potential to contaminate the USDW… Stimulation fluids in coal penetrate from 50 to 100 feet away from the fracture and into the surrounding formation. In these and other cases, when stimulation ceases and production resumes, these chemicals may not be completely recovered and pumped back to the coalbed methane well, and, if mobile, may be available to migrate through an aquifer."*[174]

Water Quantity

Rural residents across the country have experienced decreases in the levels of their drinking water wells, as well as the drying up of springs.[175] Monitoring wells maintained by the federal Bureau of Land Management in the Powder River Basin of Wyoming/Montana have indicated a drop in the aquifer of more than 200 feet.[176] Estimates are that the water levels could drop to a total of 600-800 feet over the course of CBM development in that basin.[177]

Spontaneous Combustion of Dewatered Coalbeds

The EPA has reported the spontaneous combustion and continued burning of completely dewatered coalbeds as a concern related to CBM development.[178] When water is pumped out of coal seams, coal becomes exposed to oxygen, and coal fires are possible. This can occur spontaneously, or from lightning strikes or ignition by grass fires or wildfires. The areas most likely to be the site of a coal fire are along the edges of basins where coal is close to the surface and oxygen can most easily enter the coal when water is removed. At least one coal fire is burning north of Sheridan, Wyoming. This old fire could expand as dewatering lowers the groundwater level (thus exposing more coal to oxygen).[179] If coal fires occur, by-products, such as polycyclic aromatic hydrocarbons (PAHs), from the underground fires could potentially lead to contamination of underground sources of drinking water.[180]

Compaction/Subsidence

Water is part of the fabric of a geologic formation—it holds the rock open. When water is removed from the rock, the pore spaces are left open, and the rock can collapse. In parts of the world, there have been incidents where enormous quantities of water have been removed from shallow aquifers, followed by as much as a 40-foot drop (or subsidence) in the surface of the land. The consequences of the subsidence have included the rupturing of utility lines (gas, sewage, water, electric), collapse of buildings, and damage to roads.[181]

Noise

From exploration through site abandonment, noise is generated by truck traffic, heavy equipment, seismic explosions, drilling rigs, motors that power pumps, and gas compressors. The noise from all of the equipment may be a frustration for landowners. The constant noise from pumps and compressors, however, can greatly affect a landowner's quality of life, and have negative impacts on livestock and wildlife. (Read Impacts Associated with Oil and Gas Operations, later in this chapter and landowner stories in Chapters IV for more information on noise.)

FIGURE I-26.
IMPROPERLY CONTAINED CAVITATION PRODUCTS.
A worker attempts to remove coal dust from trees.

Cavitation

The coal brought to the surface (100 tons on average) during cavitation is burned on site, which can last anywhere from 7 to 10 days. The pollution from burning this waste coal can be a concern for nearby residents, especially because oil and gas well "completion techniques" like cavitation are largely unregulated (e.g., they are exempt from certain environmental laws like the *Clean Air Act)*.

Cavitation Fire

In 2001, a fire outside of Durango, Colorado, was ignited during the cavitation of a coalbed methane well. When the well was surged the escaping gas ignited a grass fire, which quickly spread to surrounding trees. Fortunately, the fire did not reach any of the nearby residences. The total cost of the fire suppression was estimated by the Bureau of Land Management to be $500,000.

— Pearson, Mark. October, 2003. "Coalbed Methane Well Ignites Forest Fire."[182]

- Pollution normally associated with coal burning includes: nitrogen oxides, carbon dioxide greenhouse gases, sulfur dioxide, lead and mercury.
- The noise associated with cavitation is a major concern for landowners, livestock and wildlife. As mentioned above, jet-like noises can last for up to 15 minutes. If no notice is provided to landowners, the abrupt and shocking sound can startle livestock and residents.
- According to one landowner, cavitation is one of the most "intimidating, dramatic and disruptive gas well processes that impacts the living conditions" of residents in the Ignacio-Blanco gas field in Colorado and New Mexico.[183] He describes: huge plumes of coal dust and methane, which is then flared, producing an enormous fireball blast, often larger than the height of the drilling rig; the blast also creates shock waves; the material removed from the cavity is almost entirely coal, which is burned in a "blooie pit," creating fire balls of the size mentioned above.

It is possible that coal debris could find its way into local drinking water wells. The underground explosions are not contained, and consequently, could come in contact with groundwater flows.

Decline in property values of 22%
La Plata Country, CO

Decline in Property Values

A study in La Plata County, Colorado, found that the location of a coalbed methane well on a property at the time of sale led to a net reduction in selling price of approximately 22%.[184]

TIGHT SANDS AND GAS SHALES

The methods used to extract the gas from sands and shales are similar to those used for coalbed methane, i.e., drilling of a well, followed by a period of dewatering, and then gas production. As with coalbed methane, developers of tight sands and gas shales are fairly certain that they will encounter gas when drilling.

The main issue for companies seeking to extract gas from tight sands and gas shales is that more than 90 % of wells require some form of stimulation to achieve commercial production rates. This tends to make most operations uneconomic. Should highly efficient technologies for extracting gas from tight sands ever be developed, the potential for tight sands development is enormous, as most geologic basins contain some tight-sands gas.[185]

Many drilling, completion and stimulation technologies for tight sands and gas shales were developed during the 1980s and 1990s, when industry received a tax credit on nonconventional natural gas production.[186] Numerous stimulation experiments were conducted in an attempt to increase the flow of gas by creating fractures in the tight-sand formations. Massive hydraulic fracturing projects and stimulation using nuclear explosions were undertaken, with some success. The tax incentives were critical in the development of both gas shales and tight sands. When the tax credit expired, there was a decline in the drilling of tight sands and gas shale wells.

Five basins currently dominate tight sands activity in the US: South Texas, East Texas, San Juan (Colorado/New Mexico), Permian (Texas and New Mexico) and the Green River basin of Wyoming. In 1999, annual tight sands gas production was 2,900 billion cubic feet (Bcf), up from 1,500 Bcf in the mid 1970's.[187]

Today more than 28,000 gas shale wells produce nearly 380 Bcf of gas yearly from five U.S. basins: Appalachian (New York, Kentucky, West Virginia, Ohio), Michigan, Illinois, Fort Worth (Texas) and San Juan (Colorado and New Mexico)[188] More than 17,000 productive gas shales wells were drilled between 1978 and 1999, with a peak of 1,799 gas shale wells in 1992, the last year wells could quality for tax credits.[189]

The major issues related to tight sands and gas shales are similar to CBM: impacts associated with drilling; produced water; and methods used to stimulate gas flow (e.g., hydraulic fracing). These issues are discussed elsewhere in this document.

TAR SANDS AND OIL SHALES

Nonconventional oil deposits include heavy oils, tar sands and oil shales. As mentioned previously, petroleum is a broad term for hydrocarbons that includes gases, highly fluid "light" oils, viscous "heavy" oils, tars and bitumens. Today, light oils comprise approximately 95 % of petroleum production.[190] As will be discussed below, when compared to conventional deposits and methods, the amount of work required to produce an equivalent amount of crude oil from tar sands or oil shales makes it cost prohibitive under most circumstances.[191]

Tar sands (also known as oil sands) are grains of sand that are intermixed with bitumen (heavy, black, viscous, asphalt-like oil). Often, the bitumen is much too viscous to be recovered by conventional methods.

There are two primary methods of extracting heavy oils and bitumen from tar sands:

1. The deposits are mined, the oil removed, and the sands returned to the pit or disposed of in another manner. Approximately two tons of tar sands must be dug up, moved and processed

to produce one barrel of oil,[192] and about 75 % of the bitumen can be recovered from the sand.

2. In situ (i.e., in place) recovery is used for bitumen deposits buried too deeply for mining to be practical (usually more than 250 feet, and frequently more 1000 feet below the surface). Recovery involves injecting substances such as steam or hot solvents, which heat up the sands and cause the bitumen to become viscous enough to be pumped.

After the heavy oils and bitumen are extracted, they are thinned using another petroleum product. This enables the product to flow through a pipeline. Some upgrading (removal of some substances and addition of others) also occurs to produce a higher quality crude oil. Upgrading is responsible for 60 % of the costs, emissions and energy-use involved in the production of synthetic crude oil from bitumen.[193]

At the present time, tar sands are being mined extensively in the Athabasca oil sands in northeastern Alberta, Canada. Mining operations there produce the equivalent of 350,000 barrels of crude per day, while in situ methods produce 150,000 barrels per day. In the U.S., small deposits of tar sands are located in Utah, Kentucky, Kansas, Missouri, California, and New Mexico, but these are not presently being exploited.[194]

In the 1970s, the availability of $88 billion in federal subsidies for synthetic fuel production created a rush on tar sand development in the Book Cliffs of northern Utah. But when the subsidies ran out in the early 1980s, the tar sands development ended.

Oil shale, essentially a hybrid of oil and coal,[195] is a fine-grained rock that contains a hydrocarbon material called kerogen. Similar to tar or oil sands, the recovery of oil from oil shale uses two primary methods:

1. Mining techniques bring the oil shale to the surface. Oil is then recovered from the oil shale using retort methods (i.e., heating shale in the absence of air) at temperatures approaching 950° F. This converts kerogen into oil and gas, and yields between six and 50 gallons of oil per ton of shale.
2. An in situ retorting technique is used where hot gases and air are injected into holes that have been bored into the underground shale deposit. The kerogen is converted to oil underground, and is extracted using conventional oil extraction techniques.[196]

The largest and some of the richest deposits of oil shales are located in western Colorado, eastern Utah, and southern Wyoming. If an economic recovery method could be developed, it is estimated that these deposits alone could yield between 500 billion[197] and 1.5 trillion barrels of oil.[198] This is a phenomenally large resource, considering that there is general consensus that current global conventional reserves of oil are approximately 1,000 billion barrels.[199]

At today's petroleum prices, however, oil shale exploitation is not economically competitive with extraction from conventional reservoirs.[200] During the so-called "energy crisis" of the 1970s, when the cost of conventional oil soared, interest in mining oil shales also increased. As mentioned previously, billions of dollars in federal subsidies were offered to encourage nonconventional fuel production. Several oil shale leases on federal lands in Colorado and Utah were issued to private companies, large-scale mining facilities were developed on the properties, and experimental in situ retorting was carried out on one of the lease tracts. The Exxon Corporation went so far as to begin constructing entire new towns to support their developments, but when petroleum prices began to fall in the 1980s, their projects were abandoned. Unocal operated the last large-scale experimental mining and retorting facility in western United States, which closed in 1991.[201]

The Future of Oil Shale Development in the U.S.

The U.S. Department of Energy recommends that the U.S. establish a 2-million-barrel-per-day oil shale industry by 2020.

— U.S. DOE March 2004.
www.fc.doe.gov/programs/reserves/npr/[202]

TAR SANDS AND OIL SHALES—ISSUES AND IMPACTS

Should the development of tar sands and oil shales become economically feasible (either due to global oil economics or governmental subsidies), the developments would create a number of environmental concerns.

- When tar sands or oil shales are mined, the operations create issues similar to those created by hardrock mining operations.[203] For example, the mining operations require the stripping thousands of acres of fertile ground to get at the bitumen 40 feet under the surface, often requiring the clearing of forests and destruction of wildlife habitat.
- Unless properly removed, the nitrogen and sulfur in oil shale oil can form nitrogen and sulfur compounds that contribute to air and water pollution.[204]
- Tar sands extraction and processing requires massive amounts of water (either from surface or groundwater sources) for steam-stripping and sand washing.[205]
- Direct discharges and fugitive emissions from the processing and refinery facilities generate major amounts of toxic and carcinogenic (cancer-causing) contaminants, which may spread for miles over human and animal habitats.[206]
- The sands and shales must be disposed of after the petroleum has been extracted. If improper disposal methods are used, oil and phenol contamination may occur.
- Other by-products and potential contaminants related to oil shale extraction include uranium, vanadium, zinc, alumina, phosphate, sodium carbonate minerals, ammonium sulfate, and sulfur.[207]
- Each stage of tar sand and oil shale processing and upgrading requires the use of significant quantities of energy, which mainly comes from burning fossil fuels (usually natural gas). "It takes so much energy to extract the sticky low-grade oil off of a grain of sand that it almost isn't worth it. If one were to do a net energy analysis, they would find that would it almost takes as much energy to mine, process, refine, and upgrade the bitumen oil out of tar sands as the oil-energy that would be produced from the tar sands. Thus, in the process you generate much more carbon dioxide emissions getting the tar sands oil out than you would from extracting and processing conventional oil."[208]
- It has been estimated that tar sands mining and processing generates between 5 to 10 times more carbon dioxide (CO_2) emissions than the extraction and processing of conventional oil.[209] The National Energy Board of Canada estimates that approximately 275 lbs of greenhouse gas emissions[210] are released per barrel of synthetic crude oil from tar sands;[211] approximately 200 lbs of which occur at the tar plant. The CO_2 emissions from a tar sands plant having a capacity of 150,000 barrels per day would equal putting another 1.35 million automobiles on the road.[212]

Impacts Associated with Oil and Gas Operations

Some impacts from oil and gas development may be positive for surface owners. The enjoyment of benefits depends upon a couple of factors:

1. Do you own the mineral rights?
2. Is some of the infrastructure associated with oil or gas development useful to you?

The primary benefit of oil and gas development to mineral owners is financial. If you own the mineral rights you will receive royalties on any oil or gas that are removed from your property. The extent of your financial gain, however, depends upon the productivity of the well, and what sort of royalty provisions you are able to negotiate in your leasing agreement. Secondary benefits may be derived from any compensation received for surface damages, as well as perceived benefits from improvements such as roads and fences.

In the 1980s, a study on the benefits and costs of oil and gas development to ranchers in New Mexico was conducted.[213] Below is a summary of the benefits and costs mentioned by the ranchers.

The authors of the study discussed the fact that almost all of the cash benefits (an average of $28,000 over the life of the well) occurred early in the exploration and development process, and that most were one-time payments. Meanwhile, the costs to ranchers averaged $5,750, per year, for the life of the oil or gas operation. The report concluded that for ranchers not receiving annual royalty payments: it is evident ***the rancher is a net income loser if the life of the oil field exceeds six years.***

Examples of benefits received by ranchers	Examples of costs to ranchers
• Lease payments (this only applied to those who owned their mineral rights) • Direct compensation payments for the disturbance of the land surface (e.g., loss of grazing land; roads; right-of-way easements; pipelines) • Payments for seismic tests • Purchase of fresh and brine water used for drilling • Purchase of gravel for road building • Subcontracting ranch labor, e.g., to reseed, build fence • Year-round road network (conversion of existing roads to all-weather status) • Cattle guard and gate installation • Conversion of dry oil and gas holes into productive wells for watering livestock.	• Long-term loss of land carrying capacity • Inadequate compensation for land disturbance • Additional labor hours • Increased cattle deaths • Reduced calving percentage • Reduced average market weight of cattle

If landowners do not own the minerals beneath their land, there is often no guarantee that they will be fairly compensated for property damage from oil and gas development. (See sections II and III for more information on compensation.) Many surface owners who have experienced oil and gas development wonder why their quality of life and livelihoods suffer, while the oil and gas industry reaps huge financial profits at their expense. This question was also addressed by Randy Udall, Director of Community Office for Resource Efficiency, when delivering the keynote address at a 2002 Coalbed Methane Conference in Montana:

> *A typical coalbed well will yield $1 million in gross revenues, so there's enough money to protect the environment, farmers, ranchers, and water quality. . . Why should their stockholders be the only ones that benefit from gas development on private property? With $1 million in revenue per well, gas producers could/should share some of it with the landowner.*[214]

Industry is not solely responsible for ensuring that surface owners are treated fairly. Federal and state governments share in the responsibility to ensure that property owners do not absorb a disproportionate amount of impacts and costs related to oil and gas development. Unfortunately, in many regions, governments do not live up to this responsibility.

> *The [Department of Environmental Quality] continues to exonerate itself with a laissez-faire attitude toward releases that cause evacuation and injury claiming it is "impossible to legislate or prevent accidental releases." The state's rationalization becomes that those who are gas victims simply live, through luck of the draw, in the wrong place, and will inevitably be subject to this additional "normal" hazard of life. "We do not live in a risk free society" as Fitch [Supervisor of Wells] reiterates. "The gas must be extracted from where it lies." In other words, gassed and displaced families are simply the sacrificial lambs whenever small independent, limited liability corporations choose to move in.*
>
> —Excerpt from *Survey of Accidental and Intentional Hydrogen Sulfide Releases Causing Evacuations and/or Injuries in Manistee and Mason Counties from 1980 to 2001.*[215]

The potential costs or impacts to surface owners from development of oil or gas on or near their property can be summarized in three categories: health, safety, and welfare (or quality of life).

FIGURE I-27.
IMPROPER NETTING AND FENCING
Can result in death of wildlife and livestock.

HEALTH, SAFETY AND QUALITY OF LIFE

The potential costs or impacts to surface owners (and communities as a whole) from the nearby development of oil or gas can be summarized in three categories: health, safety, and welfare (or quality of life).

Health impacts may result from: surface and groundwater contamination; dust and air pollution; soil contamination; noise pollution; light pollution (e.g., if drill rigs operate 24-hours-a-day); and stress related to living in an industrial zone.

Safety may be endangered due to: potential home fires and explosions (e.g., due to methane or hydrogen sulfide seepage); potential of fires or pollution from accidents or improper worker conduct in the field (e.g., blowouts; valves left open); flooding related to poor water and waste management practices; increased community crime resulting from an influx of new workers; and reckless driving by oil or gas workers.

A decline in quality of life may result from: economic issues that arise from energy development (e.g., decline in property values; attorney fees related to negotiations with companies); noise; water well depletion or loss; degradation of water quality; land disturbance and soil erosion; vegetation die-off; the presence of industrial facilities (unsightly buildings and odors); damage to roads; and traffic congestion.

Several of these issues are addressed in more detail below.

The following information on housing, crime, roads, and dust emissions related to coalbed methane (CBM) development comes from a study conducted in Wyoming. As part of the Wyoming Energy Commission Community Outreach Program, the Commission contracted with a consultant, Pedersen Planning Consultants, to perform community assessments related to CBM development in six counties – Campbell, Sheridan, Johnson, Sweetwater, Converse and Carbon.[216] The information below reflects insights and recommendations from various community leaders.

Soil erosion can be unsightly; it can lead to excessive turbidity in streams; and the loose soils can create problems with dust and decrease visibility.

Housing

Since 1998, the coalbed methane boom in Campbell, Sheridan and Johnson counties has increased housing costs and decreased availability of rental apartments and homes to purchase. The lack of housing frustrates workers who are working 12-hour shifts, as they have little time to make an extensive search for housing. Increased housing costs have increased the overall cost of living for most households in Campbell County. Law enforcement representatives point out that these stresses have contributed to more petty theft, domestic violence, and other criminal behavior.

Crime

Campbell County has experienced an increase in larceny, destruction of private property, family violence, and child abuse since CBM development came to the county. The heavy amount of shift work has resulted in children being left at home unsupervised. Other crimes are attributed to alcohol and drug problems, which are linked, in part, to the increase in CBM development – as more people in the community earn more income, greater drug usage occurs. Ninety-nine percent of all crimes in Johnson County tie back to drug or alcohol abuse. Police from the City of Gillette report that methamphetamines are a growing community concern because of the addictiveness of these drugs. As more money is needed to sustain the drug habit, both sellers and users often commit crimes to obtain money. Drug users are also more likely to be involved in marital and child abuse.

In Sheridan County, there has been an increase in population of at least 300 people since 1998. Many of the new residents are CBM workers and their dependents. The county has experienced an increase in aggravated assaults from 40 in 1998 to 90 assaults in 2000. Burglary and larceny crimes also increased considerably during that period.

In both Sheridan and Campbell counties, the CBM development has affected the ability of the sheriff's department to hold on to their employees. The higher wages offered by CBM companies have enticed many experienced crime prevention workers to leave their jobs and join the CBM industry. It is also more difficult to attract new police recruits, as the higher wages again draw more young men and women to the industry jobs.

Safety

There are no local or state-wide safety standards being applied in the coal bed methane exploration and production areas of Wyoming. Most of the larger CBM companies, however, have adopted their own operational and safety standards, but subcontractors do not necessarily follow them (and companies do no monitor their subcontractors to ensure that they are following the company's safety standards). In the aftermath of some industrial accidents, the Campbell County Fire Chief has witnessed CBM contractor crews that were somewhat drunk and/or unprepared to carry out work safely.

Roads

In Sheridan County, 50% of county roads have been impacted by CBM development, while in Campbell county more than 25% have been affected. Increased road usage by the CBM industry and new residents has reduced the facility life of the roads, and has increased the cost of road operations and maintenance. In Sheridan County, some impacts on county roads are being mitigated by CBM companies that sign road "user agreements" with the county (in which the companies agree to: repair road damages beyond normal wear and tear; restore roads to existing condition; and provide labor and materials for road repairs). Even with these agreements, however, Sheridan County estimates that $8.7 million will have to be spent on road improvements in the county and City of Gillette.

Dust

Another consequence of CBM development is significant dust emissions along county roads. Horses in some areas of Sheridan County have experienced chronic coughing from increased dust emissions. Some ranchers in Campbell County have found that cattle do not eat grass that is within 0.25 miles of both sides of some county roads. Some counties are applying magnesium chloride to suppress dust; others are using gravel, which is thought to be a more effective dust suppressant. Campbell County, which does not have its own gravel source, imports gravel for dust suppression at a cost of $6/ton.

Property Values

In some Wyoming counties, housing values, in general, have increased due to the recent boom in CBM development combined with an overall housing shortage in those counties.

A study conducted in La Plata County in Colorado, found that despite an overall increase in housing values between 1990 and 2000, the selling price for properties that had an oil or gas well on them was <u>22% less</u> than a similar property without a well on site.[217]

Interestingly, the study found that if a property did not have a well, but was located within 550 feet of a property with an oil or gas well, that the non-well-bearing property <u>increased</u> in value. The authors suggested that this occurred because buyers assumed that there was a low likelihood of two wells being drilled right next to each other. This assumption may have disappointing results for those buyers, however, because state agencies can and do change well spacing requirements – especially as the oil or gas field ages – and wells may eventually have to be drilled in between existing wells in order to get more oil or gas out of the formation. (Read about well spacing in the section on Field Organization earlier in this chapter)

Noise

Many landowners choose to live in rural areas because they want to live a peaceful life. Oil and gas development, however, can greatly affect the peace and tranquility of rural areas, and can become a major annoyance to those living close to oil and gas facilities. This, in turn, may affect a person's health and quality of life. The following section provides an overview of noise issues for landowners dealing with oil and gas development. See Chapter V for additional resources related to noise.

Noise from oil and gas development comes from a number of sources: truck traffic, drilling and completion activities, well pumps and compressors.

In general, the volume of a sound is measured in decibels (dB). According to the World Health

Organization, outdoor sound that exceeds 55 dB begins to be a nuisance to people.[218] During the nighttime hours (10 p.m. to 7 a.m.), sound levels in rural or quiet suburban areas are often as low as 25 to 35 dBA,[219] while urban areas may be 80 dB or more.[220]

Oil and Gas Development Noise

In a La Plata County, Colorado study[221] noise levels were reported for a number of oil and gas activities and equipment:

- A typical compressor station: 50 dBA* at 375 feet from the property boundary (noise emitted 24-hours-a-day)
- Pumping units: 50 dBA at 325 feet from the well pad (noise emitted 24-hours-a-day)
- Fuel and water trucks: 88 dBA at 50 feet; 68 dBA at 500 feet
- Crane (used to hoist rigging equipment): 88 dBA at 50 feet; 68 dBA at 500 feet
- Concrete pump (used during drilling): 82 dBA at 50 feet; 62 dBA at 500 feet
- Average well construction site: 85 dBA at 50 feet; 65 dBA at 500 feet

*Often, equipment used to measure sound is designed to account for sensitivity of human hearing to various frequencies. This is known as A-weighted correction, and the measurement is an A-weighted decibel (dBA).[222]

How Sound Travels—Sound is caused by changes in air pressure. For example, when a mallet strikes a drum the drumhead begins to move back and forth (vibrate). As the drumhead moves down, air is pulled toward it, and as the head bounces back up it pushes air away. This creates changes in air pressure that move (or propagate) away from the drum, eventually striking our eardrum. These changes in pressure are known as sound waves.

There are a number of factors that affect the propagation of sound. The most important include: distance from source; obstacles such as barriers and buildings; atmospheric absorption; wind direction and speed; temperature and temperature gradient; humidity; precipitation; reflections; and ground absorption.[223]

Prolonged periods of noise exposure to 65 dBA can cause mental and bodily fatigue.

It is important to understand that noise does not always decrease as one moves away from a noise source. The above factors can work to increase or decrease noise levels. For example, at short distances (up to 160 feet) the wind has a minor influence on the measured sound level. At distances greater than 1,000 feet from a noise source, noise can become louder on the downwind side by as much as 20 dB, while on the upwind side levels can drop by 20 dB (depending on wind speed and distance).[224]

Other things to consider include the fact that while barriers may act to reduce high frequency sounds, low frequency sounds are difficult to reduce using obstacles or barriers. Additionally, while soft ground surfaces and the atmosphere are effective at absorbing mid-frequency and high frequency noise, these factors do not tend to reduce low frequency noise to the same degree. This means that as one moves away from the source, low frequencies often become much more prominent.[225]

What Makes Certain Sounds Annoying?—Whether a noise is objectionable will vary depending on its type (tonal, impulsive, etc.), the circumstances (e.g., does the noise occur in an area where there are already loud noises versus a quiet rural setting), and the sensitivity of the individual who hears it. Certain noise characteristics can greatly increase the annoyance and the health impacts associated with a noise. These factors include: 1) tonality; 2) impulsiveness 3) fluctuation or intermittence and 4) presence of low frequencies.

When a noise contains sound that has distinct frequency components (tones), e.g., noise from fans, compressors, or saws, the noise is generally far more annoying than other types of noise. *Most energy industry facilities typically exhibit either a tonal or impulse/impact component.*[226] Impulsive noise comes from impacts or explosions, e.g., from a pile driver, or pieces of pipe hitting one another. The noise is brief and abrupt, and its startling effect causes greater annoyance than would be expected from a simple measurement of the sound decibel level. Fluctuating noises, as well, may be far more annoying than predicted by average sound levels.[227] Oil and gas pump jacks can create fluctuating and intermittent noises. Pump jacks may operate and automatically shut off for specific periods of time. When improperly maintained, pump jacks can develop intermittent rubbing noises or squeaking noises that occur at regular intervals. Regular variations in noise have been found to increase the annoying aspects of the noise.[228]



FIGURE I-28. NOISE EXAMPLES
Left to right: Pump jack noise is intermittent; compressor noise is constant and long-term; noise from drill rigs is short-term but very loud.

Some jurisdictions have developed noise regulations that penalize individuals or industries that generate tonal, impulsive or fluctuating noises. For example, if a noise has an obvious tonal content, a "penalty" or correction may be added to account for the additional annoyance.[229] Currently, the penalty for tones varies between 0 dB (no penalty) and 6 dB.[230] The penalty is added to the measured decibel level, and this combined decibel level is compared to the acceptable decibel standard.

- For example, if the noise from a compressor is measured as 49 dBA, but it is determined that the noise has tonal components, a penalty of 6 dBA would result in a noise level of 55 dBA. If the acceptable noise standard is 50 dBA, the noise from the compressor would be out of compliance.

Low Frequency Noise—Low frequency noise is experienced by some landowners who live near oil and gas facilities. Low frequency noise does not have a consistent definition, but it is commonly defined as noise that has a frequency between 20 and 100 - 150 Hz (in other words, sound waves are vibrating between 20 and 150 times per second).

Low frequency noise can be generated by numerous sources during oil and gas production.[231]

- Low frequency noise is produced by machinery, both rotational and reciprocating, and all forms of transport and turbulence. Typical sources include pumps, compressors, and fans.
- The firing rate of many diesel engines is usually below 100 Hz, so road traffic noise can be regarded as low frequency.

- Combustion turbines are capable of producing high levels of low frequency noise. This noise is generated by the exhaust gas.[232]
- Burners (and flares) can emit broadband low frequency flame roar.

Low frequency noise creates a potential for
. It is well established, however, that the annoyance due to a given noise source is perceived very differently from person to person. For many humans, their ears are not very sensitive to low levels of low frequency sound. At low frequencies, however, noise may not be perceived as sound but rather may be "felt" as a vibration or pressure sensation.[233]

For those who are sensitive to low frequency sound the effects can be dramatic.[234] Complainants often describe the noise as:

- Humming or rumbling
- Constant and unpleasant
- Pressure in ears
- Affects whole body
- Sounds like large, idling engine
- Coming from far away

Researchers have conducted field measurements and laboratory studies of people who have complained of low frequency noise in their homes. Studies have found that:[235]

- Problems tend to arise in quiet rural or suburban environments
- The noise is often close to inaudibility, and is heard by a minority of people
- The noise is typically audible indoors and not outdoors
- The noise is more audible at night than day
- The noise has a throbbing and rumbly characteristic
- The complainants have normal hearing

FIGURE I-29. VENTING OF GAS WELL CAN BE PIERCINGLY LOUD.

Despite the fact that the World Health Organization has stated that, "The evidence on low frequency noise is sufficiently strong to warrant immediate concern," few noise regulations in the United States address low frequency noise. Some counties in northern Michigan have developed ordinances that reference low frequency noise as a separate than other noise issues.[236] Most of the research and regulation related to low frequency noise has taken place in European countries and Japan. See Chapter V for resources related to Low Frequency Noise.

Health Effects of Noise

There are adverse physical and mental effects from noise. For example, prolonged periods of exposure to 65 dBA can cause mental and bodily fatigue. Furthermore, noise can affect the quantity and quality of sleep; cause permanent hearing damage; contribute to the development or aggravation of heart and circulatory diseases; and transform a person's initial annoyance into more extreme emotional responses and behavior.[237]

According to the World Health Organization:[238]

> Noise annoyance is a *global phenomenon. A definition of annoyance is "a feeling of displeasure associated with any agent or condition, known or believed by an individual or group to adversely affect them."*

. . .apart from "annoyance", people may feel a variety of negative emotions when exposed to community noise, and may report anger, disappointment, dissatisfaction, withdrawal, helplessness, depression, anxiety, distraction, agitation, or exhaustion.

. . . Social and behavioural effects include changes in overt everyday behaviour patterns (e.g. closing windows, not using balconies, turning TV and radio to louder levels, writing petitions, complaining to authorities); adverse changes in social behaviour (e.g. aggression, unfriendliness, disengagement, non-participation); adverse changes in social indicators (e.g. residential mobility, hospital admissions, drug consumption, accident rates); and changes in mood (e.g. less happy, more depressed).

The World Health Organization also reports that "a large proportion of low-frequency components in noise may increase considerably the adverse effects on health." In an epidemiological survey of sufferers from low frequency noise, the following health effects were documented:[239]

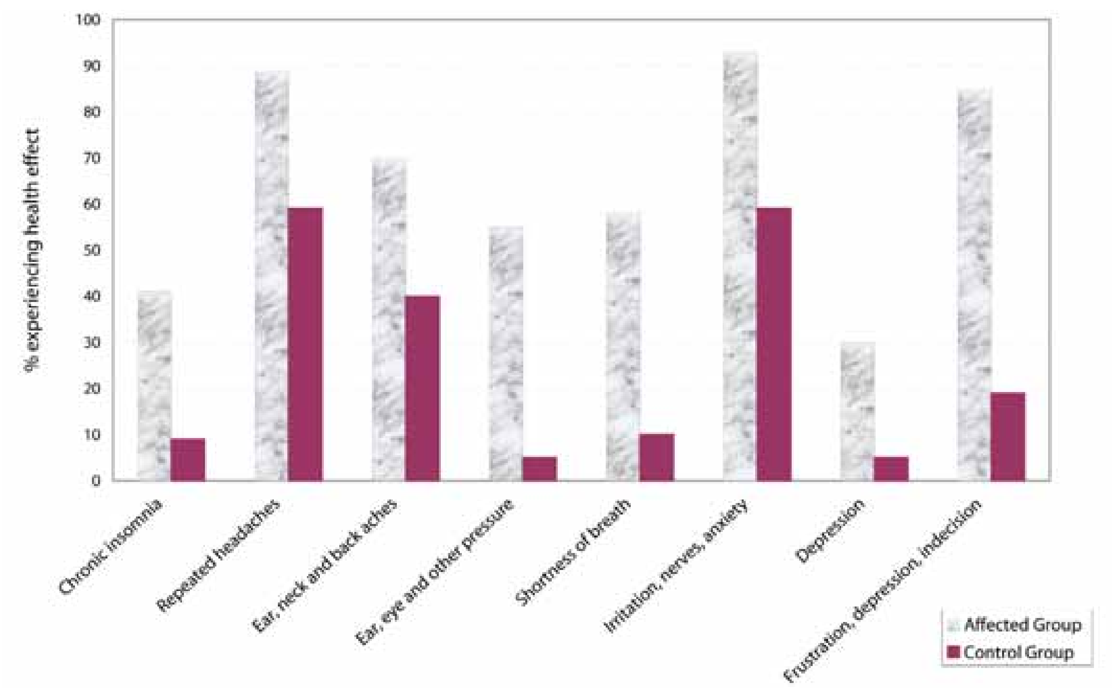


FIGURE I-30. HEALTH EFFECTS OF LOW FREQUENCY NOISE
Source: Mirowska, M. and Mroz, E. 2000.[240]

The above health effects were felt by people experiencing low frequency noise in their homes. The New Mexico Game and Fish states that even for human beings in a recreational setting, low frequency noise has been shown to cause stress reactions including raised blood pressure and increased muscle tension.[241]

Unfortunately, many of the health effects of noise due to oil and gas operations have not been scientifically documented. The lack of scientific study does not mean, however, that noise issues related to oil and gas are insignificant. The loud, continuous noise during the drilling phase; the loud short-term noises from flaring or hydraulic fracturing; the intermittent whine of poorly maintained pump jacks and other equipment; and the loud or low frequency noise from compressors are common complaints related to oil and gas development. Numerous citizens have reported disruption of sleep and increased anxiety caused by noise from oil and gas developments.[242]

To illustrate the frustration with noise generated by compressors, here is one landowner's experience:

> *Now comes the second phase. The dreadful noise generated by a nearby large compressor station. Noise that was so loud that our dog was too frightened to go outside to do his business without a lot of coaxing. Noise that sounds like a jet plane circling over your house for 24 hours a day. Noise that is constant. Noise that drives people to the breaking point. My neighbor called the sheriff, state officials and even the governor and was told nothing could be done about the noise. Like I said, the noise drives people to the breaking point, and my neighbor fired 17 rifle shots toward the station.*
>
> —Excerpted from CBM Destroys Retirement Dream.
> The full story from this landowner can be found in Chapter IV.[243]

For more landowner stories related to noise, see Chapter IV. See the section on Alternative Technologies and Practices later in the chapter for information on how to decrease noise levels.

CONTAMINANTS ASSOCIATED WITH THE OIL AND GAS INDUSTRY

The following table summarizes the types of wastes that are generated during the various stages of oil and gas development.

Of these wastes, there are some that pose more serious concerns for landowners than others. These include specific air emissions; hydrocarbon wastes; produced water; and naturally occurring radioactive materials (NORM). These are discussed in more detail on the following pages.

	Air Emissions	Waste Water	Residual Wastes	Oil and Gas Industry Contaminants That Are Hazardous to Human Health
Well Drilling and Completion	• fugitive natural gas • other volatile organic compounds (VOCs) • polyaromatic hydrocarbons (PAHs) • carbon dioxide • carbon monoxide • hydrogen sulfide • methane	• drilling muds • organic acids • alkalis • diesel oil • crankcase oils • acidic stimulation fluids (hydrochloric and hydrofluoric acids)	• drill cuttings (some oil-coated) • drilling mud solids • weighting agents • dispersants • corrosion inhibitors • surfactants • flocculating agents • paraffins	• arsenic • benzene • cadmium • chlorinated paraffin waxes • chromium • carbon monoxide • 1,2-dichloroethane • dichloromethane • ethylbenzene • hexachlorobenzene • hydrogen sulfide • lead • nickel • polycyclic aromatic hydrocarbons (PAHs) • polychlorinated dibenzodioxins • polychlorinated dibenzofurans • radon and radium • toluene • trichloroethylene • uranium • volatile organic compounds • xylene
Production	• fugitive natural gas • other VOCs • PAHs • carbon dioxide • carbon monoxide • hydrogen sulfide • methane migration • fugitive BTEX (benzene, toluene, ethylbenzene, and xylene) from natural gas conditioning	• produced water possibly containing: arsenic, sulfur, metals (e.g., lead, nickel, zinc, antimony, barium), radionuclides (uranium, radon, radium), dissolved solids, and high levels of salts (e.g., sodium, chloride, potassium, magnesium) • produced water also may contain additives such as biocides, lubricants and corrosion inhibitors • wastewater containing glycol, amines, salts, untreatable emulsions, and hydrocarbons (e.g., benzene, toluene and naphthalene)	• produced sand • elemental sulfur • spent catalysts • separator sludge • tank bottoms • used filters • sanitary wastes	
Maintenance	• volatile cleaning agents • paints • other VOCs • hydrochloric acid gas	• completion fluid • wastewater containing well-cleaning solvents (detergents and degreasers), paint and stimulation agents	• pipe scale • waste paints • paraffins • cement • sand	
Abandoned Wells, Spills and Blowouts	• fugitive natural gas • other VOCs • PAHs • particulate matter • sulfur compounds • carbon dioxide • carbon monoxide	• escaping oil produced water brine	• contaminated soils • sorbents	

Adapted from: Sittig, 1978; EPA Office of Solid Waste, 1987. [244]

AIR EMISSIONS

As seen in the table below, there are several types of air emissions in the drilling and production process. The following table provides information on air quality concerns related to oil and gas in different parts of the country.

Some of the key sources of air emissions include the following:

Regional Air Quality Concerns from Oil and Gas Development

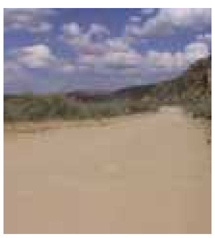
Pollutant or Impairment	Gulf Coast	North Slope	San Joaquin Valley	Rocky Mountain Region	California Coast
Visibility	A concern	An issue	Serious impairment in summer & winter	Degradation a serious concern	A possible concern
Sulfur dioxide, sulfate				A concern	
Ozone	A serious concern		A serious concern	An serious issue in some areas; a potential in others	A concern
Acid Deposition				A new issue and serious concern	
PM-2.5; PM-10 (particulate matter 2.5 or 10 microns in diameter)	A concern		A serious concern	Potentially an issue	A potential concern
Carbon Monoxide		A concern			

Adapted from: the U.S. Department of Energy [245]

1. Fugitive emissions from leaking tubing, valves, tanks, and open pits, or intentional venting of natural gas may release volatile organic compounds (VOCs)[246] and hydrogen sulfide.
   - VOCs are carbon-containing substances that readily evaporate into the air. They can combine with nitrogen oxides to form ground-level ozone, which can cause respiratory ailments such as asthma, and decreased lung function (see following page for more information). Examples are benzene and toluene.
2. Particulate Matter is essentially small particles that are suspended in the air and settle to the ground slowly. These particles may be re-suspended if disturbed. The most common sources of particulate matter from oil and gas operations are dust or soil entering the air during pad construction or from traffic on access roads; and diesel exhaust from vehicles or engines used at oil and gas facilities.
   - PM_{10} particles (with diameters less than 10 micrometers or µm) are small enough to be inhaled and can cause adverse health effects.
   - $PM_{2.5}$ particles (with diameters less than 2.5 µm) can lodge deep within the lungs and cause serious health problems. $PM_{2.5}$ particles are the main cause of visibility impairment (haze). Secondary particles are formed through chemical reactions involving gases and other particles in the atmosphere. Particles formed in this manner are fine particles (< 2.5 µm). The most common precursor gases involved in these reactions are nitrogen oxides (NOx), sulphur dioxide (SO_2), volatile organic compounds (VOCs) and ammonia (NH_3).[247] SO_2, NO_x and VOCs are all emitted during oil and gas operations.
   - For residents living along unpaved roads or near well pads, dust can penetrate their homes causing a nuisance and health problems such as hay fever and allergies. Crops

Studies over the last 15 years show that low levels of ozone, most certainly at 50 to 60 parts per billion (34-24 ppb below the federal limit) are detrimental to health.

American Journal of Respiratory and Critical Care Medicine and vegetation near unpaved roads can be covered with the airborne dust stunting their growth due to the shading effect and clogging of the plant's pores. As a result, cattle and wildlife may avoid this vegetation. For motorists using the unpaved roads the traffic-generated dust can reduce visibility and cause driving hazards.



Dust can affect human health, and the health of crops, livestock and wildlife.

Dust Suppression

WATER is probably the oldest of all dust suppressants. Typically, it is applied by spraying it over the road surface.
Drawbacks: Water's dust suppressing capacity is very temporary because of evaporation. Heavy applications of water can create soft mud or penetrate the road to the sub-base and causing major road failure. Consequently, several light applications are preferable to one heavy application.

CHLORIDE COMPOUNDS such as calcium chloride ($CaCl_2$), magnesium chloride ($MgCl_2$) and the less popular sodium chloride ($NaCl_2$) are used because they attract and absorb moisture from the atmosphere and retain it for extended length of time, which significantly reduce the evaporation of moisture from the road surface. Thus, they are more effective dust suppressants than plain water.
Drawbacks: Chloride compounds have the disadvantage of dissolving in water, and therefore can be washed out during wet weather conditions. They are also corrosive.

LIGNIN DERIVATIVES include a variety of industrial waste products, animal fats, and vegetable oils; the most popular is ligninsulfonate, which is a waste product from the paper-making industry. When used as dust suppressant, the lignin polymers act as glue binding the soil particles together. According to the New Mexico State University Molecular Biologic Program, a by-product of the soybean crushing process, called soapstock, is now being used as dust suppressant on dirt and gravel roads throughout the Midwest. This alternative is said to be more environmentally safe in places where runoff is a concern, and supposedly lasts longer than most other alternatives.[248]
Drawbacks: Ligninsulfonate dissolves in water, and so it is easily washed away during wet weather conditions.

RESINOUS ADHESIVES include waste oils, tars, bitumen, and by-products from the plastic industry. Of all these products, cutback asphalt and asphalt emulsions are most widely used as dust suppressants.
Drawbacks: According to the Minnesota Pollution Control Agency, "When applied to roads, waste oil can seep into groundwater, runoff into surface waters or spread into the air with dust particles. Once in ground or surface waters even small amounts of used oil can contaminate large quantities of drinking water. . . Used oil reduces the amount of oxygen in water, damaging fish and other aquatic life."[249] Consequently, waste oils are prohibited from use as a dust suppressant in Minnesota.Very little quantitative information currently exists on the environmental impacts from the use of dust suppressants (other than water). Landowners should be aware that the application of dust suppressants has been noted to cause slipperiness on unpaved roads in wet weather conditions. The water quality effects of the use of dust suppressants are still not entirely known, however the chloride compounds and the lignin additives commonly used contain contaminants such as chlorides, heavy metals and organic compounds that are regulated by the U.S. Environmental Protection Agency.[250]

ALTERNATIVES TO WATER AND CHEMICAL DUST SUPPRESSANTS[251]

LOWERING SPEED LIMITS will decrease the amount of dust stirred up from unpaved roads and pads. Lowering the speed of a vehicle from 45 miles per hour to 35 miles per hour can reduce emissions by up to 22 %. Installation of speed bumps can reduce vehicle speeds.

UPGRADING UNPAVED ROADS (e.g., by improving particle size, shape, and mineral types that make up the surface and base materials) will increase a road's surface strength, and reduce dust emissions. Adding surface gravel can reduce the source of dust emission, but if gravel is added the amount of fine particles (i.e., those smaller than 0.075 mm) should be limited to 10 to 20 %. Also, improving drainage and crown can reduce dust emissions. Paving is the most expensive, but most effective road upgrade option.

3. The flaring of natural gas produced from the oil or gas wells may release carbon monoxide, nitrogen oxides, sulfur dioxide, benzene, toluene, ethylbenzene and xylene, polycyclic aromatic hydrocarbons (PAHs) and, in the case of sour gas, hydrogen sulfide and carbon disulfide.
    - Benzene and PAHs are carcinogenic (cancer-causing). Also, benzene has been shown to cause various adverse health effects other than cancer, such as blood disorders,

impacts on the central nervous system, and reproductive effects.[252] Toluene, ethyl benzene, xylenes can affect human reproduction and respiratory systems.[253]

- Nitrogen oxides combine with VOCs to form ground-level ozone.
- Hydrogen sulfide is a neurotoxin (poisonous to the brain—see below).

4. Fuel combustion associated with the use of machinery including pumps, heater-treaters, and diesel engines, turbines and motors may release nitrogen oxides, sulfur oxides, ozone, carbon monoxide, and particulates.
   - Nitrogen oxides combine with VOCs to form ground-level ozone.
   - High concentrations of ozone near ground level can be harmful to people, animals and crops. ozone can irritate the respiratory system and inflame and damage cells that line the lung. Also, ozone may aggravate asthma and chronic lung diseases such as emphysema and bronchitis, and reduce the immune system's ability to fight off bacterial infections in the respiratory system. And ozone may cause permanent lung damage, with the worst effects being felt in children and exercising adults.[254]

Ozone (O_3) is formed when volatile organic compounds (VOCs) and nitrogen oxides (NO_x) react in the presence of sunlight and heat.

$$\text{VOCs} + NO_x + (\text{sunlight/heat}) = O_3$$

San Juan County Ozone Alert—In San Juan County, New Mexico, there are approximately 18,000 oil and gas wells currently in production. Per year, these wells emit an estimated:

- 6,900 tons of VOCs (57% of all VOCs emitted in the county)
- 29,000 tons of NO_x (25% of all NO_x emitted in the county)

At these levels of emission, the area is very close to the EPA's maximum allowable ozone concentration of 84 parts per billion (ppb). But with the Bureau of Land Management predicting an additional 12,500 new wells, 12,000 new compressors and 319 large compressors stations for the region, San Juan county may exceed ozone levels of 84 ppb in the future. This would endanger the health of county residents, especially children, the elderly, and residents who do a lot of outdoor exercise.[255]

In San Juan County, New Mexico, a typical summer day has ozone levels higher than 50 ppb and frequently exceeds 70 ppb.

Data from NM Environment Dept., Air Quality Bureau, www.nmenv.state.nm.us/aqb/

5. Wastes generated during natural gas dehydration and sweetening may release glycols and benzene.
   - Glycols are volatile and can be hazardous if inhaled as a vapor.[256]

6. The extraction of produced water during coalbed methane development may lead to migration of methane gas to the atmosphere. (See produced water below.)
   - Methane can form an explosive mixture in air at levels as low as 5 percent. Symptoms of methane exposure include burning eyes, dizziness and headaches.[257]

7. Accidental and intentional releases of hydrogen sulfide may occur at sour gas well operations. When H_2S burns it forms sulfur dioxide and trioxide (SO_2 and SO_3, respectively), which contribute to air pollution and health problems. Furthermore, because H_2S is heavier than air, it often settles in low-lying areas, where it can accumulate in concentrations

that can injure or kill livestock, wildlife and human beings. As well, hydrogen sulfide gas has been found to migrate into surface soils, groundwater and into the atmosphere from coalbed methane production (in association with methane gas).[258]

- Common symptoms affecting those exposed to chronic, periodic or puff releases of low levels of H_2S include: headache, skin complications, respiratory and mucus membrane irritation, respiratory soft tissue damage and degeneration, confusion, impairment of verbal recall, memory loss and prolonged reaction time.[259] Brief exposures to H_2S are neurotoxic, effects are persistent, and exposures to low doses appear cumulative. . . downwind environmental exposure to H_2S can cause permanent impairment; "neighborhoods near refineries and other industrial sites where H_2S is released deliberately or inadvertently are unsafe."[260]
- Hydrogen sulfide has an effect on cattle at concentrations of 50 ppm, and can cause death to cattle at higher concentrations.[261]

Carol Browner, former Administrator of the U.S. Environmental Protection Agency (EPA) made no secret of the fact that hydrogen sulfide was eliminated from the Clean Air Act list of extremely hazardous substances by powerful last minute oil and gas lobbying.[262] This elimination occurred in spite of the fact that the EPA study, Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas. . . documented a large number of oil and gas related accidents occurring in North America and concluded that accidental releases of H_2S pose the greatest risk to public health.
—Excerpt from page 3, *Survey of Accidental and Intentional Hydrogen Sulfide Releases Causing Evacuations and/or Injuries in Manistee and Mason Counties from 1980 to 2001.*

For more resources on air emissions, see Chapter V.

HYDROCARBON WASTES

Hydrocarbons are compounds that are made primarily of carbon and hydrogen molecules. Examples of hydrocarbons associated with oil and gas operations include: crude oil, waste oils, natural gas, methane, BTEX, phenols, PAHs, and some solvents.

FIGURE I-31. BENZENE WARNING SIGN
A conventional gas operation in Wyoming. Photo by Wyoming Outdoor Council.

Health effects associated with hydrocarbons include: respiratory ailments, effects on neurologic, cardiac and gastrointestinal systems, and skin disorders. Some hydrocarbons are known to cause cancer (e.g., PAHs and benzene). The amount of exposure and how the exposure occurs (e.g., skin contact, ingestion, inhalation) influence which bodily systems are affected and the extent of damage to the systems.

Hydrocarbon spills and waste pits pose a health threat to wildlife and livestock. Waterfowl, wildlife and livestock may be attracted to pits and open tanks used to store oil, separate oil from produced water, or store produced water. The risks posed to wildlife by oil waste pits have been documented by numerous studies.[263]

- In Wyoming, the U.S. Fish and Wildlife Service have found deer, pronghorn, waterfowl, songbirds and rabbits in oil pits and tanks. Even if animals are not killed in the pits, the oil and chemicals in the pits may affect their health. For example, if animals absorb or ingest oil, they may become more susceptible to disease and predation.[264]
- Landowners should suggest that companies use closed containment systems (e.g., tanks). These require little or no maintenance and may be reused at other well operations. The

benefits for the companies are that these systems greatly reduce or eliminate soil contamination, thereby reducing remediation costs.

- Other measures to protect wildlife and livestock include systems to prevent oil from entering waste pits; immediately cleaning up any oil spills into open pits; adequate fencing around waste pits and tanks; and netting to keep birds from entering waste pits. If netting is not installed properly or maintained well enough (e.g., if there are tears in the netting or if it sags into the waste pit, which is common after it snows), the oil will be exposed. Nets should be installed four or five feet above the pits to allow for sagging.[265]

For example, a study conducted in 1994 documented the effects of a pipeline spill on livestock.[266] Cattle on two ranches were exposed to a mixture of gases including hydrocarbon vapors, sour gas, and sulfur dioxide. The study concluded that:

- there was an increase in illness and death in both herds
- calves suffered a “failure-to-thrive syndrome” (i.e., calves failed to nurse, had slow weight gain, and were prone to infection)
- open sores and other evidence of exposure to irritating substances were observed in the upper respiratory tracts of calves
- changes in maternal behavior were observed in both herds
- some cattle had difficulty in placement of their limbs

Releases of Hydrocarbons—Land and Water

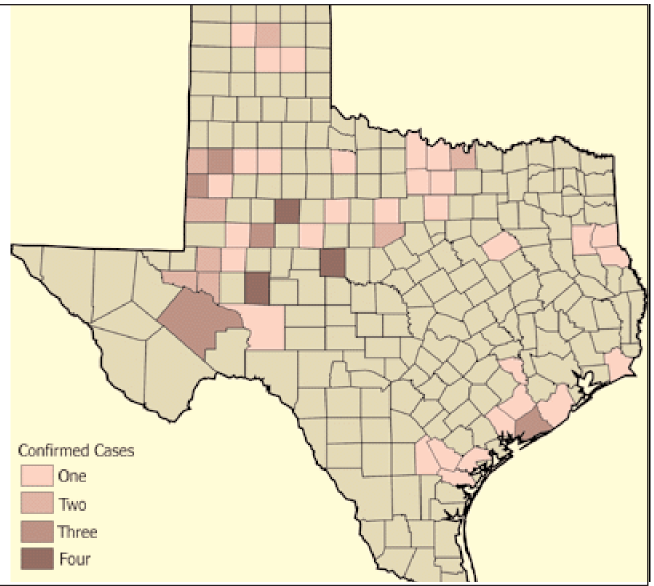
In addition to hydrocarbons being emitted into the air, releases of hydrocarbons can flow across the land surface, seep into the soils and groundwater or flow into surface waters. Releases of hydrocarbons may occur in a single event, e.g., a spill, or over longer periods of time, e.g., seepage from pits, or slow leaks from pipes and storage tanks. Spills are the most common type of release and are often small in quantity.[267] Spills and seepage may result from human error, equipment failure, improperly designed containment facilities, past oilfield practices, vandalism, or natural phenomena (e.g., lightning strikes, flood damage).

- Spills of hydrocarbons may come from several sources or operations at production and drilling sites: leaking tanks, pipes, flowlines, valves, joints, or gauges; blowouts (see box on next page); oil transfers; diesel from drilling operations; offloading of oily drilling muds and production chemicals.
- High concentrations of hydrocarbons are found in the bottoms of oil storage tanks (i.e., tank bottoms), which contain a mixture of crude oil, salt water, sand, and scale from the tank itself.

FIGURE I-32. SOUTHEAST NEW MEXICO: Left: produced water pit with layer of oil on top. Right: Leaking waste-oil tank. No netting and inadequate fencing allows access to these toxic hydrocarbon wastes. Photo by C. Johnson.

Groundwater Contamination

In Texas, groundwater has been affected by the thousands of Texas drilled for oil and gas exploration. When improperly drilled or cased, or when the casing has corroded, old oil, gas, and water wells serve as conduits for contamination of the aquifers below. Improperly completed and abandoned water wells may allow direct access from the surface to groundwater for contaminants such as pesticides, or they may facilitate the comingling of groundwater from one aquifer to another.[268]



Oil and gas exploration and production wastes are exempt from federal hazardous waste regulations.

Signs of hydrocarbon contamination include: dead vegetation, stained soil, oil in depressions or in pits, or an oil sheen on the surface of nearby ponds and streams. It is less easy to detect hydrocarbons that have soaked into the soil, and whether or not those hydrocarbons are interacting with groundwater.

Hydrocarbon Disposal

At the present time, oil and gas exploration and production wastes are exempt from federal hazardous waste regulations.[269] This leaves the decision of how to dispose of potentially hazardous hydrocarbon wastes in the hands of the oil and gas operator. Should contamination occur due to the mismanagement of hydrocarbon or other wastes, the company could be held liable for the clean-up costs.[270] This assumes, however, that either the federal government or landowner has the desire or economics means to take the company to court.

The federal ruling does not exempt oil and gas operators from waste regulations imposed at the state level. Unfortunately, some state waste regulations do not appear to be a great enough incentive to properly dispose of oil and gas wastes. For example, in New Mexico, the state Oil

Weld County Waste Disposal

The Weld County Waste Disposal, Inc. site was a 40-acre commercial waste disposal facility originally permitted to receive oil field brines and other petroleum related liquid waste generated from oil and gas exploration and production activities. Liquids received were transported in an aboveground pipe to a clay-lined impoundment where liquid hydrocarbons were separated from the produced water (brine) and recycled. The water was transferred to a second clay-lined impoundment where enhanced evaporation occurred as the primary water disposal method.[271]

Weld County Waste Disposal Inc., is currently undergoing site investigation and remediation under the federal government's Environmental Protection Agency (EPA) supervision. The site was found to represent an "imminent and substantial endangerment" to the environment under the Resource Conservation & Recovery Act (RCRA). Initially, it was targeted because the operator failed to keep the pond surface clear of oily residue, which led to the death of several great blue herons. Once the facility was brought under RCRA, however, EPA required a full site investigation. This investigation and the related remediation are expected to cost oil and gas operators that "contributed" waste to the facility some $3 million (the site operator declared insolvency).[272]

Conservation Division has been investigating contamination in two regions where there is oil and gas development. Out of 734 cases of soil or groundwater contamination statewide, 444 were at oil or gas field production locations.[273]

In New Mexico, about half of all exploration and production wastes (other than produced water and drilling muds and cuttings) are disposed in pits, about 45% are diverted to oil "reclaimers," and the remainder of the wastes are buried on-site.[274]

These disposal methods are typical for the industry. In addition to pit disposal and burial, landfarming (the process of spreading waste oil on soil) is a standard industry practice for disposing of hydrocarbon wastes. In many jurisdictions, oil companies may use a designated area for spreading oil or hydrocarbon-contaminated soils, as long as the land is not going to be used for agriculture.[275] Landfarming may involve the bioremediation of the soil, to decrease the levels of hydrocarbons. To achieve bioremediation, hydrocarbon-digesting microbes found naturally in soil are enhanced with fertilizers and moisture to degrade the material. The site is tilled periodically and watered to maintain proper amounts of air and moisture.[276]

Many oil and gas operators choose to send hydrocarbon wastes such as tank bottoms to commercial oil field waste disposal facilities, or reclaimers. The crude oil reclamation industry recovers marketable crude oil and other hydrocarbons from produced water, tank bottoms and other oily wastes that are generated by the production of oil and natural gas. Marketable crude oil is recovered from the waste materials by simple thermal and/or physical processes (e.g., heat and gravity separation). As with on-site waste pits, these off-site facilities pose a significant risk to migratory birds and other wildlife because they use large evaporation ponds to dispose of and treat oil and gas wastes. Commercial facilities that dispose of wastewater through deep well injection generally do not pose a risk to wildlife, but may pose a threat to groundwater resources.[277]

FIGURE I-33. LEAKING TANKS CAN THREATEN GROUNDWATER. Note the hydrocarbon stains on the soil.

Well Blowouts

A well blowout is defined as the uncontrolled flow of fluids from a well bore. These fluids, which include hydrocarbons, produced water, drilling fluids and others, can contaminate soils surrounding the well bore, seep into groundwater, and flow into nearby water courses.

Most commonly, a blowout occurs when there is insufficient pressure in a well bore to control subsurface pressures. During drilling, completion, or plugging and abandonment operations, proper well-bore pressure control is the key to preventing blowouts; the primary method is through hydrostatic pressure, which is created when a well is filled with fluid (e.g., drilling mud).[278]

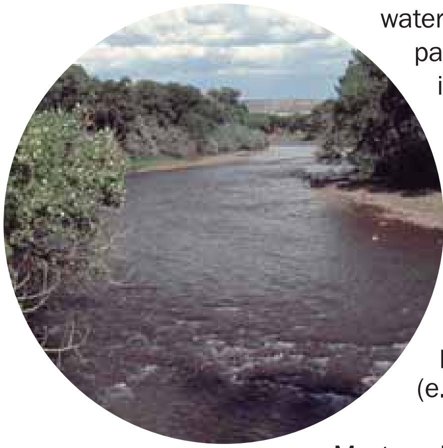
According to the California Department of Conservation, there are three main causes of blowouts during drilling operations, all stemming from human error: 1) failure to maintain adequate drilling fluid weight; 2) failure to keep the hole full of drilling fluid; and 3) failure to prevent swabbing. These categories accounted for about 55 percent of the blowouts that occurred in California from 1950 to 1990.[279]

Between the years 1950 and 1990 there were 101,578 oil and gas wells drilled in California. During this period there were 135 blowouts from onshore operations (52 during drilling; 17 during completion; 10 during plugging and abandonment; 61 during other well operations).

- Blowouts lasted anywhere from a few minutes to 13 days
- Materials that were spewed from the wells during the blowouts included: oil, gas, mud, rocks, sand, gravel, water, saltwater, steam, and casing and tubing parts.
- There were injuries or deaths associated with 28 of the blowout incidents. In total, there were seven deaths and 52 injuries reported.[280]

PRODUCED WATER

There are a host of health and safety concerns associated with produced water. The quality and quantity of water removed present threats to human and ecological health; and the removal of water creates other issues such as potential for underground coal fires, and creation of pathways for methane to migrate to the surface. All of these issues are discussed later in this section.



Water Quality

Pumping oil and gas out of the ground produces large volumes of water, which often contains large amounts of dissolved salts (e.g., chloride, nitrate, nitrite, sodium, calcium, magnesium and potassium), inorganic substances (e.g., antimony, arsenic, barium, boron, cadmium, chromium, copper, lead, lithium, mercury, nickel, silver and zinc);[281] hydrocarbons (benzene, ethylbenzene, naphthalene, toluene, phenanthrene, bromodichloromethane, and pentachlorophenol) and radionuclides (e.g., uranium, radon, and radium).

Most produced water has attributes that make it undesirable or unfit for human or agricultural use.

- Oil, sulfur and phenol can be smelled and tasted.
- Studies on produced water from California oilfields have revealed incidents where concentrations of phenols and arsenic posed a threat to human health.[282]
- As mentioned above, benzene is a known human carcinogen and can cause blood disorders, impacts on the central nervous system, and reproductive effects; and ethyl benzene and toluene are known to human reproduction and respiratory systems.
- In high enough concentrations, sodium, carbonates, phosphates, borates, sulfates, magnesium, potassium, iron, fluorine and organic chemicals found in produced water may all contribute to the deterioration of the water supply. For example, if chloride is present in high concentrations it can cause water to taste salty, and soap suds will not form as well. And boron, which is non-toxic to humans in low concentrations, can produce a laxative effect in animals (concentrations of 40 ppm).[283]
- Produced water often has high salinity (dissolved salt content). Total salinities of oil- and gas-field produced water range from about 1,000 milligrams per liter to more than 400,000 mg/L. The U.S. EPA's recommended safe drinking-water limit is 500 mg/L.[284] Waters with salinities between 0 and 400 mg/L are acceptable for all crops; and salinities above 5,000 mg/L are considered too saline for almost all crops.[285] Also, if produced waters are discharged onto land surfaces, the salts can build up in the soil and affect plant growth.

The concentration of contaminants in produced water varies from region to region and depends on factors such as the geology, depth of the production zone, age of the well, and well stimulation techniques.[286]

- Radionuclides in produced water are found only in some areas of the country (see discussion on NORM below).
- In most oil and gas producing areas, produced water from deeper wells has a higher salt content than water from shallow wells. In basins where the rocks consist mainly of shales or siltstones, however, fresher water may be found at greater depths.[287]
- If wells undergo acidization or hydraulic fracturing, residual chemicals will be removed along with produced water. The chemicals used vary be operator and geological formation.

Water Quantity

Every minute, a CBM well may pump as much as 15 gallons of produced water.[288] This may lead to significant drawdown of local and regional aquifers and reduction of ground and surface water supplies. As mentioned in the chapter on Coalbed Methane, some aquifers in coalbed methane producing areas have fallen by 200 feet or more.[289] The BLM estimates that groundwater levels in the Powder River Basin will drop by 600 to 800 feet, if that region develops their CBM resources at the BLM's intended rate.[290]

If regional groundwater levels become too depleted, local springs, streams, domestic and stock water wells, and subirrigated acreages will be affected.[291] Significant reduction in these waters would be harmful or fatal to aquatic life and wildlife; crop production could decrease; and carrying capacities and distribution patterns for livestock and wildlife could be significantly and adversely affected.[292] This could have a devastating impact on local/regional ecosystems and economies dependent on them.

Dewatering of Coal Beds

Coal will not burn as long as it is saturated with water. But when coal beds are dewatered, and especially if they are close to the surface, the coal may catch on fire from lightning strikes, wildfires and spontaneous combustion. This is a potential concern to landowners because once underground coal fires begin to burn, they are almost impossible to put out; the burning coal releases carbon monoxide; and the layers of rock and soil above the coal can collapse as the coal continues to burn.[293] Carbon monoxide can lead to fatigue in healthy people, chest pain in people with heart disease, and at higher concentrations, it can cause impaired vision and coordination; headaches; dizziness; confusion; or nausea.

Methane and Hydrogen Sulfide Migration

Massive dewatering of aquifers may also lead to increased methane or hydrogen sulfide (H_2S) migration to the surface. In some areas, dewatering (which releases methane from the coal), and the structure and layering of the geology create pathways that allow these gases to flow to the surface.[294] The escape of methane or H_2S can also result from inadequate well control procedures and faulty casing or plugging.[295] The gas can then collect in explosive levels in homes. Methane and H_2S seepage/venting may be one of the most disastrous problems facing landowners living in close proximity to CBM operations.[296]

> *EPA spoke with a former county employee, who worked for Exxon performing hydraulic fracturing jobs in an earlier career. As a county employee, he took measurements for methane and hydrogen sulfide inside homes in response to citizen complaints. According to his information, there were not significant problems until the shallowest formation, the Fruitland coal, began being developed. He believes that the main route of contamination is from older, poorly cemented wells. The county official estimated that hundreds of wells have been impacted. He said the biggest problem associated with the apparent effects of CBM development is explosive levels of methane and toxic levels of hydrogen sulfide in homes. In his opinion, this is due to removal of water rather than hydraulic fracturing.* — Excerpt from EPA's *DRAFT Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs.*[297]

Disposal of Produced Water

The United States produces 20 to 30 billion barrels of produced water every year.[298] Prior to the enactment of environmental regulations in the 1970s, produced water was disposed of using the most economical method. This often resulted in the intentional discharge of the water on the ground surface.[299] Today, the most common methods of disposal are injecting it into the

FIGURE I-34. HYDROGEN SULFIDE WARNING
Hydrogen sulfide may be associated with produced water.

subsurface, evaporating it in disposal ponds, and releasing it to watercourses such as rivers or ephemeral streams.

Injection/Reinjection: Approximately 90% of onshore produced water from conventional oil and gas sites is reinjected into a well for production enhancement, or disposed of by injection into a disposal well.[300]

Reinjection of produced water to enhance the recovery of oil or gas typically involves a closed system from the producing well bore to the injection well bore, so the potential for spills and soil contamination is minimized.[301] Production enhancement is discussed in the section on Stages of Oil and Gas Development.

When using disposal wells, produced water is usually required to be injected into known formations, such as a former producing formation, or aquifers known to have water quality that is worse than the quality of produced water.[302] If water is being injected into a formation, the formation must be capable of receiving the huge volumes of injected water. But subsurface geology is not always known or predictable, and there may be unintended consequences from injection of produced water. (See the box on BP-Amoco's reinjection problems.)

At a BP-Amoco well southeast of Durango, Colorado, CBM produced water was reinjected into an aquifer that, unbeknownst to the company, connected to a natural fracture system. The produced water traveled underground and forced hot water that had been in deep aquifers up toward the surface. This caused a nearly 50 degree Fahrenheit temperature increase in a hot spring 1½ miles north of Durango. Water output at the hot spring also increased. The temperature at the hot springs decreased after BP-Amoco agreed to inject water into a different aquifer. Nancy Van Dover, a local resident, told the Colorado Oil and Gas Conservation Commission how disposal wells had caused her well-water temperature to rise to 100 degrees. The water also became highly mineralized and destroyed her sink, toilets and shower. [305]

Produced water from CBM operations is not used to enhance methane recovery. Underground injection is, however, used as a method of disposal of CBM produced water.[303] Also, if the water is of good enough quality, produced water may be injected into a formation that will store the water, which will enable it to be retrieved at a later date.

Storage or Disposal in Evaporation Ponds or Percolation pits: Produced water may be placed in pits and allowed to either evaporate or percolate into the surrounding soil. According to the U.S. EPA, this approach is declining because of potential contamination of groundwater and the potential hazard posed to birds and waterfowl by residual oil in these open pits.[304]

Often, impoundments do not contain water effectively, and leaks are common. Water may end up in rivers and streams, increasing the salts in these watercourses. The water also evaporates from the pits, which wastes water that could otherwise be used to recharge aquifers.[306]

Swamping may also be an issue if produced water is held in ponds. Near Gillette, Wyoming, produced CBM water is often stored in ponds before it is discharged in drainage systems. In some cases, produced water has seeped from the ponds into near-surface sediments. Sediments can only absorb so much water, and if additional water cannot be transmitted fast enough to deeper soils surface swamping will occur.[307]

The oil and gas industry often talks about creating a beneficial use for produced water. One of these supposed beneficial uses is the creation of artificial ponds or reservoirs using produced water that is non-toxic to wildlife. This may seem like an environmentally sound option for the water, since the reservoirs can provide wildlife habitat, fish ponds and recreation areas. The problem is that over time, CBM water production will decline. When this happens, ponds and reservoirs will dry up, green areas will turn brown, and wildlife and fish that have come to rely on this source of water will lose their habitat. As one critic puts it: “Creating and then destroying environs in this callous fashion is an unacceptable impact to the land.”[308]

Discharge to Streams: For this disposal method the water is supposed to be treated to meet standards for oil and grease content, and pass a toxicity test prior to discharge. There are some negative effects associated with this practice:

- Often, enormous quantities of CBM produced water are discharged all year long, which alters the seasonal nature and timing of natural flows. If such practices are allowed to continue, the water volume of some rivers may be doubled, and streamside trees and plants that have adapted to the previous water conditions may not be able to survive.[309]
- Dumping large volumes of produced water into streams can wash away stored nutrients, and without these food sources, aquatic organisms may not be able to survive.
- In Wyoming and Montana, it is common practice to dump produced water from CBM operations into streams. Often, however, discharges are permitted into streams and rivers without proper testing.[310] This poses a danger to aquatic life and landowners living downstream who use the water for irrigation, since the produced water may contain high concentrations of salts and dissolved solids.

Surface Discharge: Discharges of produced water on land may flood the property of landowners, which can lead to erosion and damage to soils and plants.[311] The effects of the surface disposal of produced waters can also include swamping; siltation of streams, lakes, and reservoirs; and contamination of soil, ground water and surface water by salts, hydrocarbons, metals, and radioactive materials.[312]

The discharge of produced water inappropriately onto soil can result in salinity levels too high to sustain plant growth. In some areas, however, produced water may contain low enough levels of salt that it may be used for beneficial use for irrigation or livestock watering.

Occasionally, produced water is spread on roads as a dust suppressant. Roadspreading is declining as a disposal option, however, and in 1995 it accounted for less than 1 % of produced water disposal.[313]

The U.S. EPA estimates that 30 % of producing oilfields in the United States have enough NORM to warrant health and environmental concerns.[316] One industry estimate suggests that if strict regulatory requirements for assessment and cleanup of NORM were put in place in the United States, 20 % of oil production and 8 % of gas production would become uneconomic.[317]

NATURALLY OCCURRING RADIOACTIVE MATERIALS (NORM)

Naturally occurring radioactive materials may be present in oilfield solid or liquid wastes. As well, radioactivity may be found on oil or gas industry equipment.[314]

Depending on the geology, subsurface formations may contain radioactive materials such as uranium and thorium and their daughter products, radium 226 and radium 228. Radionuclides are leached into groundwater or surface water when the water comes in contact with uranium- and thorium-bearing geologic layers. NORM can be brought to the surface in produced water from these formations. In addition, radon gas, a radium daughter, may be found in produced natural gas.[315]

The primary carrier of the NORM is the produced water from the reservoir. When the produced water is brought to the surface, the changes in temperature, pressure and salinity cause a scale to form.[318] For example, radium 226 and 228 found in produced waters may become concentrated by attaching to barium sulfate scale in well tubulars and surface equipment. Elevated concentrations of radium 226 and 228 may also occur in sludge that accumulates in oilfield pits and tanks.[319] Often, high concentrations of oil-and-gas-related NORM are associated with separator tanks, water storage tanks, and water lines where brine scale and tank sludge accumulate.[320] Consequently, workers employed in the area of cutting and reaming oilfield pipe, removing solids from tanks and pits, and refurbishing gas processing equipment may be exposed to radioactive materials that could pose health risks.[321] The main health risks for humans are direct gamma radiation from NORM-bearing soils and equipment, breathing of NORM-bearing dust, or breathing indoor radon in structures built on NORM-affected soils.[322]

Some study results:

- High concentrations of radioactivity associated with oil fields have been found in the Gulf Coast region, northeast Texas, southeast Illinois, Oklahoma, and south-central Kansas. Also, state agencies have identified radioactive oil-field equipment in northern Michigan and eastern Kentucky.[323]
- Among 14 sites studied in the Wildhorse field of Oklahoma, oilfield equipment radioactivity or radioactivity in soils or on road surfaces exceeded regulatory limits at 10 of them. Material interpreted to be tank bottom sludges discarded on soils at production sites consistently contained the highest radium. The authors of the study warned that as the contaminated soil material ages and weathers it may be transported downslope by slope wash processes, thus contaminating a greater area. Equipment radioactivity was highest on old pipe with thick scale.[324]

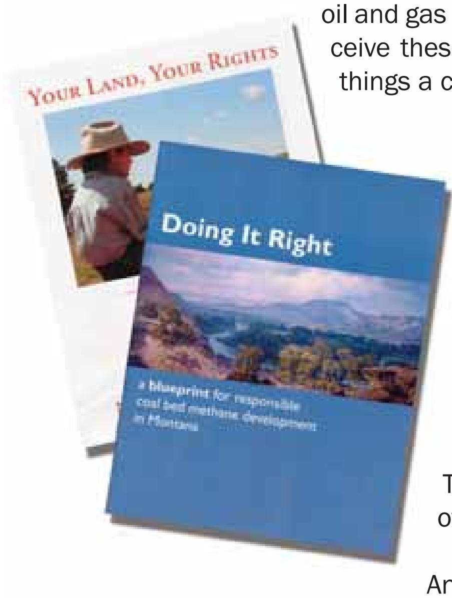
Disposal Options
In Texas, NORM-contaminated solids, such as pipe scale, may be disposed of on the site where they were generated by burial or placement in a well that is being plugged and abandoned.[325] Contaminated soil may be spread on land only under certain conditions.

Regulation of NORM
The U.S. EPA has not issued regulations limiting NORM contamination and radioactivity in oil and gas production operations. The agency is, however, assessing the extent of the problem in a wide number of industries that generate NORM, and the EPA and the Department of Energy are evaluating the health risk associated with NORM exposure in oil and gas operations.[326]

At least six states (Louisiana, Texas, Michigan, Mississippi, Arkansas, and New Mexico) have regulations that would govern some aspect of NORM in the oil and gas industry.

Alternative Technologies and Practices

Often, there are alternatives available to the standard technologies and practices used by the oil and gas industry. Sometimes companies are hesitant to use alternatives because they perceive these options as being more expensive, or the companies are simply used to doing things a certain way.



This section primarily focuses on the technologies and practices that affect the environment, and thus, affect landowners. Another realm of "Best Management Practices," however, involves policy and regulatory alternatives for developing oil and gas resources in a responsible manner that protects the rights of surface owners. These alternatives may include, for example, improving surface owner consent provisions; doing a better job of balancing surface owner and mineral owner rights; or enabling surface owners to have a greater say in the location of wells that are going to affect their property. Many of these issues are mentioned in Chapters II and III.

The Vermejo Park Ranch Mineral Extraction Agreement in Chapter III is an example of one of the better known Surface Use Agreements achieved by a landowner.

An excellent example of a template for responsible oil and gas development was produced by the Northern Plains Resource Council in Montana. Their report, *Doing It Right*, provides a proposal for how coalbed methane in that region has been developed in a way that industry, landowners and the public can live with. In summary, *Doing It Right* advocates for:

1. Effective monitoring of coalbed methane development and active enforcement of existing laws to protect private property rights, Montana citizens, and Montana's natural resources.
2. Surface owner consent, surface use agreements and reimbursement of attorney fees to help landowners better protect their property rights.
3. Use of aquifer recharge, clustered development, mufflers for compressor stations, and other low-impact, best-available technologies to minimize impacts on underground water reserves, rivers and streams, and surface resources.
4. Collection of thorough fish, wildlife, and plant inventories before development proceeds to protect habitat, followed by phased-in development to diffuse impacts over time.
5. Meaningful public involvement in the decision-making process.
6. Complete reclamation of all disturbed areas and bonding that protects Montana taxpayers from all cleanup liability costs.

The template can be used in other states, and can be applied to conventional oil and gas development. For more information on Northern Plains Resource Council and how to obtain the complete *Doing It Right* report, see Chapter V.

What will make companies use alternative technologies and practices?
In Chapter II you will learn that even though mineral owners and companies that lease mineral rights have the right to enter and use a surface owner's property to develop oil and gas, surface owners are not without rights. The use of "best management practices" is required in numerous states.[327] Courts have found that mineral owners may not cause unreasonable damage to the surface estate if there are reasonable alternative methods available to develop the minerals in a way that does not cause the damage.[328] Consequently, it is useful for surface owners to be aware of some of the alternative technologies and practices that are available. In many cases, these alternatives are already being used by some companies, so they may be considered reasonable alternatives.

Read the Landowner story "Bellflower Well" in Chapter IV for an example of how surface owners in Colorado managed to decrease the impact of a coalbed methane well on their lives by pressuring a company to use alternative practices. As the story illustrates, however, often it is not enough to simply ask companies to use alternative technologies. Typically, landowners have to diligently fight for the things that are important to them (e.g., a pollution-free, quiet, safe environment).

FIGURE I-35. BURIED TANK

Where can I find information on alternative technologies and practices?
Ultimately, surface owners will have to do some of their own research to find out about alternatives. Fortunately, there are a variety of resources available. For example, numerous organizations and government offices have developed "best management practices" for the oil and gas industry. For example, the state of Pennsylvania has developed best management practices for the development of well locations because of the hilly nature of the state and the desire to control erosion and sedimentation.[329]

Many industry web sites highlight "state-of-the-art" technologies. Industry groups and governments often provide awards to companies for implementing innovative technologies and practices. While many of these awards are simply pats on the back, it may be useful to look at some of them. You may be surprised to find that a company you have been dealing with has developed and used better technologies in other jurisdictions. If this is the case, you can try to pressure companies to apply their technologies across the board.

It is also useful to look at technologies used by companies that are active within city limits.

Often, the requirements for noise abatement, air quality and water quality are more stringent if oil or gas wells are located in densely populated areas, and as a result, companies are forced to use state-of-the-art equipment in those situations.

For example, in 2003, the Farmington, New Mexico City Council approved five gas wells only on the condition that the company agreed to: bury all condensate tanks; install double walled condensate tanks as a means of leak protection; enclose well pads with a six foot chain-link privacy fence; install sound abatement measures around all compressors and motorized equipment; and ensure that sound measurements would not exceed more than three decibels above ambient level at a distance of 300 feet from the compressor, or one decibel above ambient level at the nearest residence. The company also offered to pay for surrounding residents to stay in hotels during the drilling period, if requested.[330]

Below, you will find some examples of alternative technologies and practices. This list is by no means comprehensive, and the following practices will not be appropriate for all situations. These examples are meant to provide readers with an idea of the types of alternatives that are out there. Visit the Oil and Gas Accountability Project web site (http://www.ogap.org) and Chapter V of this guide for more information and additional resources on alternative technologies and practices that are available to oil and gas operators.

ALTERNATIVES USED DURING THE DRILLING AND COMPLETION PHASE

1. **Pitless or "closed-loop" drilling** can reduce the impact of waste pits. At a conventional drilling site, drilling fluid is circulated through the well bore, and then often deposited in a reserve pit dug next to the well. This pit is constructed prior to drilling. It is open to the atmosphere, and is used to store drilling fluid. A large storage capacity is typically required, because there are times when large amounts of drilling fluid are needed (e.g., when high pressure zones are encountered during drilling). A reserve pit can be the source of considerable costs at a drilling site because of the costs associated with properly closing pits. Also, there are health, environmental, and financial risks associated with pits, which can contaminate soils with hydrocarbons, metals and salts, and leak potentially toxic liquids into surface or groundwater.[331]

FIGURE I-36. CONVENTIONAL DRILLING SITE
This site, with reserve pits disturbs 3-4 acres of land.
Photo by Jonathan Selkowitz

Eliminating the need for earthen reserve pits is a viable option for oil and gas companies.[332] In pitless drilling, the drilled solids are separated from the mud during the drilling process, and are moved to a storage tank. The fluids are pumped to storage tanks. The drilling mud and water can be re-used throughout the drilling process. And at the end of the drilling process, the remaining water may be transported to the next drill site and used on the subsequent well.

The tanks represent an additional cost, but overall, pitless drilling can save an operator money because there is no need to construct a pit, there is a reduction in the amount of environmental releases, and the closed-loop system results in more efficient use of drilling fluid.[333]

A small independent operator in Texas was concerned that reserve pits for drilling fluid were increasing waste management costs and exposing it to liability for surface and ground water contamination due to pit failures. Because the wells to be drilled were relatively shallow and few complications were expected, the operator negotiated with the drilling contractors to use a closed-loop fluid system. The operator saved approximately $10,000 per well because the drill site construction and closure costs were greatly reduced, as were waste management costs. The operator's liability was also reduced.[334]

Benefits of pitless drilling:[335]

- it eliminates unsightly and hazardous pits
- it reduces the time, energy and expense of building, fencing and reclaiming reserve pits
- it decreases the need for cuts in sensitive and hilly areas
- total surface disturbance associated with a well pad is reduced
- it eliminates risk of waterfowl and wildlife mortality related to pits
- it eliminates risk of damaging underground pipelines and utilities
- it allows drilling in areas with a high ground water table
- it virtually eliminates drilling waste
- rigs use less water per well—it can reduce water consumption by as much as 80%
- it eliminates soil segregation, which reduces wind erosion problems
- it reduces truck traffic associated with transporting drilling wastes by as much as 75%
- it may improve relationship with surface owners
- it greatly reduced waste tracking and need for land farming operations
- drill cuttings may be put to beneficial use, e.g., if not contaminated they may provide a source of finely-ground clay for berm construction around tank batteries or other uses

2. **Redesigning pits can decrease the amount of surface disturbance**. If a pitless drilling system is not used for drilling fluids, another approach may be to use a V-shaped pit instead of the traditional rectangular pit. This type of pit reduces water requirements, as well as the amount of surface disturbance.

   The design is as follows: the open end of the "V" faces the drilling rig and the cross-sectional view resembles a squared-off funnel (about 10 feet deep with the upper 5 feet having slanted walls to a width of about 20 feet). Because the fluid must travel the full length of the pit, this design prevents mud from channeling between the discharge point and the suction point, and reduces the amount of water that must be added to maintain the desired fluid characteristics. In addition, because the V-shaped pit is long and narrow, it is easier to construct and leaves a smaller "footprint" at the site.[336]

   > *A company installed a V-shaped reserve pit and compared the costs with those incurred at similar-sized wells using a traditional pit. The company determined that pit construction time was reduced by about 40 percent, water costs for the well were reduced by about 38 percent, and pit liner costs were reduced by about 43 percent. The total cost savings were about $10,800 per well.*[337]

   It should be noted that whenever earthen pits are used to store wastes, they should be lined with multiple layers of synthetic fabric with leak detection devices between the layers.

3. **Directional drilling help to minimize surface disturbance or avoid disturbance in sensitive or special areas.** Wells do not have to be drilled perfectly vertical. Directional drilling techniques exist that allow wells to be drilled at angles (slant hole wells); allow wellbores to curve sideways (horizontal wells); or to have more than one curve (S-curve or deviated wells).

   The benefits of directional drilling are numerous. Using these techniques, companies can drill a number of wells in different directions from one well pad (multilateral wells), which can decrease overall surface disturbance by reducing the number of well pads required to drain an oil or gas field.

Studies also show that directional drilling has been successful in a variety of geological formations (e.g., shallow reservoirs, deep reservoirs, tight sands, coal beds, tar sands). Furthermore, if horizontal drilling is used in coal beds, there may be no need to hydraulically fracture the beds, resulting in a decreased potential for groundwater pollution. Perhaps the greatest benefit to the surface owner is the ability to locate well sites away from residences or other areas that surface owners do not want to be disturbed. It is now possible for companies to access oil or gas from beneath a landowner's property by drilling a well that is miles away from that property.[338]

A major benefit to the companies and mineral owners receiving royalties is increased oil and gas production. Oil- and gas-bearing formations tend to be more wide than they are deep, consequently, wells that intersect a producing formation at an angle or horizontally often can drain more of the oil and gas than purely vertical wells. There are numerous studies showing that directionally drilled wells have been able to extract 2-25 times more oil or gas than vertical wells drilled in the same oil or gas field.[339]

FIGURE I-37. A VERTICAL AND HORIZONTAL WELL DRILLED ON ONE PAD. Photo printed with permission of Vermejo Park Ranch.

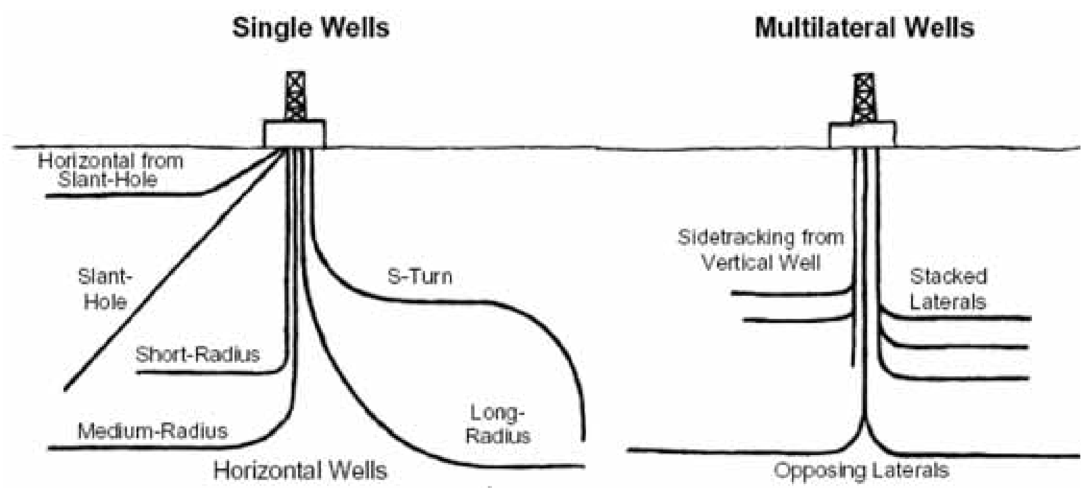


FIGURE I-38. DIRECTIONALLY DRILLED WELLS
Source: Drilling Smarter: Using Directional Drilling to Reduce Oil and Gas Impacts in the Intermountain West.[340]

The drilling of a directional well is more costly than drilling a typical vertical well because it requires specialized equipment; constant attention to the placement of the drill bit; it takes several days longer to drill the wells; and pumping costs may increase because parts may wear out faster. According to the U.S. EPA, however, the increased costs of directional drilling are often more than offset by increased production and the reduced need for drilling multiple wells.[341]

In the Dundee Formation of Michigan, as much as 85 % of the known oil remained in the formation after many years of production, but many wells were on the verge of being plugged because daily production had fallen to only five barrels of oil per well. The U.S. Department of Energy co-sponsored a project to drill a horizontal well in the formation. This well produced 100 barrels per day. The program attracted other well developers, and 20 to 30 additional horizontal wells are being drilled in the formation. It is estimated that the application of horizontal drilling to this formation may yield an additional 80 to 100 million barrels of oil.[342]

4. **Flareless or "green" completions reduce flaring and venting of natural gas.** Before natural gas and coalbed methane wells begin producing gas for sale, the well bore and surrounding reservoir must be "cleaned up" (i.e., any fluids, sand, coal particles, or drill cuttings within the well bore must be removed). The conventional method for doing this is to pump air down the well bore, which lifts the waste fluids and solids out. The solid and liquid waste materials are then dumped into a pit or tank, and any gas that is removed is flared or vented to the atmosphere. In some flareless or green completions, natural gas, rather than air, is pumped down the well bore to clean it out.[343]

   In flareless or green completions the gas that comes to the surface is separated from fluids and solids using a series of heavy-duty separators (sometimes referred to as "flowback units"). The water is discharged to tanks to be reused, the sand is sent to a reserve pit, and the gas is either cycled back through the well bore, or sent to a pipeline to be sold rather than vented or flared. According to the U.S. Environmental Protection Agency (EPA), benefits of this system include: the elimination or reduction in venting or flaring of natural gas; sale of the gas and condensate provides the operator with an immediate revenue stream; there is a reduction in solid waste and water pollution; and the system enables safer operating practices.

   Emissions Reductions: One company, which drilled 63 wells using flareless completions, reported a reduction in natural gas emissions of 7,410 thousand cubic feet per year, which is 70% of the gas that would formerly have been vented to the atmosphere.[344] Another company has been able to reduce flaring by 85-90%.[345]

FIGURE I-39. TYPICAL COMPLETION WITH A FLARE BERM AND WASTE PITS. Photo by Dan Randolph

   Costs and Pay-Back: The capital costs for companies include the use of separators, sand traps and tanks. One company reported these costs as being $180,000. The equipment, however, can be moved from site to site, so if a company were to complete 60 wells per year the annual capital charges would be less than $10,000. Operating costs are less than $1,000 per year. EPA has estimated that "green completions" can pay back their costs in about 1 year.

   An alternative to sending the gas to the pipeline is to send it to a flare tank. Flare tanks capture and more fully combust the waste gases. The tanks can be carried from site to site. This practice avoids the costs associated with excavating and reclaiming flare pits, and avoids the potential liability associated with cleaning up soils contaminated by flaring.

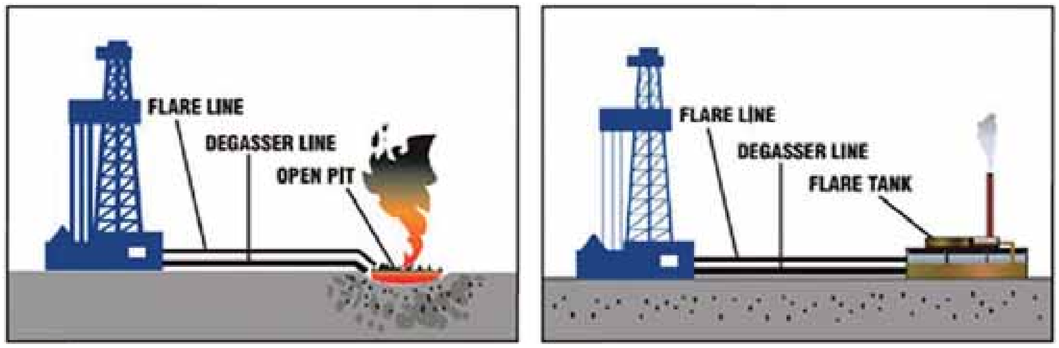


FIGURE I-40. FLARE TANKS REDUCE HAZARDOUS EMISSIONS BY MORE FULLY COMBUSTING WASTE GASES.
Source: Wellco Energy Services, Inc.[346]

5. **Waste minimization during drilling operations.** The state of Texas has produced a document *Waste Minimization in the Oil Field* that provides a general overview of waste minimization techniques for wastes arising from oil and gas operations, including drilling operations.[347] The document also provides case studies of successful waste minimization projects and a bibliography of useful technical references. The document includes dozens of examples of alternative drilling practices, such as:

   - Product substitution. Replacing conventional, toxic products with less toxic, yet effective, substitutes. For example, companies are substituting low toxicity glycols, synthetic hydrocarbons, polymers, and esters for conventional oil-based drilling fluids. The use of these substitutes eliminates the generation of oil-contaminated cuttings and other contamination by the oil-based fluid and decreases concerns related to site clean-up when the well is abandoned. Drilling engineers have published numerous technical papers that describe the successful application of substitute drilling fluids. In many instances, this substitution has resulted in significant cost savings.

     Similarly, companies have designed alternatives to the conventional water- and chemical-based hydraulic fracturing techniques, by substituting carbon dioxide for the more common and more toxic fracing fluids.

   - Process or procedural modifications. For example, in the past few years the drilling industry has improved the technology of slim hole drilling. If feasible, slim hole drilling reduces the volume of wastes (e.g., drilling fluid and the drill cuttings) produced during drilling. The total cost of a slim hole drilling operation may be considerably less than for conventional hole sizes, and smaller casing is required, which may help reduce the total cost of the operation.

   - Reduction in water use. For example, companies can reclaim water from waste drilling fluids by using mechanical or chemical separation techniques such as large bowl centrifuges, hydrocyclones, and/or chemical flocculants. The reclaimed water may then be reused, thus reducing the demand on, and cost of, new water sources. Dewatering of wastes may also result in a reduction of the volume of drilling waste to be managed, thus saving waste management costs, easing site closure concerns and costs, and reducing future potential liability concerns.

   - Preventative maintenance. For example, chemicals and materials should be stored so that they are not in contact with the ground (e.g., stored on wooden pallets), or exposed to the weather. There should be secondary containment in the case of spills. All drums and containers should be kept closed except when in use. It is very important that all chemical and material containers always be properly labeled so that their contents may be identified at any time. Proper storage and labeling of containers allows quick and easy identification and classification of released chemical or material in the event of a leak or rupture. In some instances, that could save hundreds of dollars in soil sampling and laboratory analysis costs.

- Recycling. For example, the cost of closing a drilling site is increased if waste drilling fluid in a reserve pit must be dewatered and/or stabilized prior to closure. An alternative is to recycle or reuse the waste drilling fluid, e.g., in another drilling project. One company designed a multi-well drilling project where the same drilling fluid was used for drilling each successive well. The result was significant cost savings and greatly reduced waste management concerns. Another cost effective alternative for reuse of waste drilling fluid is in plugging or spudding of other wells.

ALTERNATIVES USED DURING THE PRODUCTION PHASE

1. Minimizing Surface Disturbance

- Well pads are often much larger than they need to be—sometimes exceeding several acres in size. At Ted Turner's Vermejo Park Ranch, however, the well pads are only 0.6 acres. (See Vermejo Park Ranch Coal Bed Methane Project Mineral Extraction Agreement Summary, in Chapter III).
- After the drilling phase if over, the portion of the drilling pad not needed for oil or gas production can be reclaimed. This is known as interim reclamation, and it is required by law in many states. Unfortunately, lack of enforcement by state agencies means that interim reclamation does not occur in many jurisdictions.

FIGURE I-41. MINIMIZING SURFACE DISTURBANCE.
Left to right: Poor Practice: no efforts have been made to reduce surface disturbance at this site. Better Practice: this well site and the road leading to it have been revegetated. The surface owner has 40 additional years of use, and a 40-year head start on reclamation. Photos by Bob Miller.

2. Minimizing Visual Impacts and Noise

- Landscaping can help decrease the visual impacts of wells. For example, soil can be formed into ridges or gentle berms around the well pad, and trees and other vegetation can be planted on the ridges to screen wells so that nearby residents don't see them.
- A low-profile pumping unit can replace the conventional unit, which uses a 30- to 40-foot beam and looks like a giant, bobbing horse's head. The conventional pump is run on a gas- or diesel-powered engine, which is noisy and smelly. Alternatives to this large pump include using a pneumatic pumping device that doesn't require an engine, therefore, produces little or no noise. This pump stands about 10 to 15-feet tall. According to one company, pneumatic pumps will not function correctly if a lot of water is extracted while extracting methane gas.[348] When larger amounts of water are produced, an alterative to the standard beam pump is the progressive cavity pump. These pumps come in different shapes and sizes, and like the pneumatic pump, they can un on electric motors, and therefore, be much quieter than conventional pumps.

FIGURE I-42. PUMPING UNITS
Left to right: Conventional pump "pump jack"; progressive cavity pump; low profile progressive cavity pump.

3. Minimizing Noise

- Noise created by operators constantly driving in and out from the well pad to monitor well production can be mitigated using an automated monitoring system, which allows wells to be monitored remotely, e.g., from the company's office.[349]
- To mitigate noise impacts from engines, a sound barrier made out of four inches of insulation and 18-gauge steel can be used. Sound barriers are placed in an L-shape above the engine, and they extend past the sides of the engine.[350] Some engines can operate at a constant number of revolutions per minute (RPM), which reduces the up-down noise caused by other engines, which speed up and slow down. Mufflers, like those used for automobile engines, can be used to minimize engine noise.[351] To reduce noise in sensitive areas, well-site or field compressors may be enclosed in a sound-insulated building, and equipped with two buried hospital-grade mufflers in series.
- Noise from compressors can be mitigated by treating each significant noise source: gas turbines or engines, compressors, exhaust outlets and air inlets, and cooling and ventilation fans. Abatement may involve changing the blades on fans, which can change the frequency of sound emitted, thereby removing the annoying tones. Engine noise can be muffled using automotive-type mufflers, or by housing the engines in acoustically insulated structures. Also, the entire compressor can be housed in an acoustically insulated building.

FIGURE I-43. SOUND CONTROL
Left to right: Pump jack with sound abatement walls and muffler at lower right. The “barn” houses a compressor station. By treating each noise source, the company achieved its design goal of 40 dB at 300 feet from the station. The barn-like building was designed to fit into the rural countryside; source: ATCO Noise Management. [352]

FIGURE I-44. SOUND CONTROL
Left to right: Sound is directed up; sound is directed away from a house, but is not absorbed; sound is effectively reduced with absorbing panels to 1 decibel above ambient.

4. Minimizing Air Pollution

- If the control valves on a pump’s separator unit, which separates the methane and water, are replaced with better valves, methane emissions to the atmosphere can be reduced. This will have positive environmental benefits, as methane is a powerful greenhouse gas that contributes to global warming. By replacing 3,300 controllers on 2,760 wells in Colorado and New Mexico, the Colorado Oil and Gas Conservation Commission expects that methane emissions will be reduced by 12,000 tons per year in the San Juan Basin.[353] According to an engineer with the company BP, replacing valves not only has a positive benefit with greenhouse gases, it also has a positive economic benefit for that company.[354]
- Emissions can be reduced by monitoring and pinpointing fugitive emissions, and then sealing the leaks; using lower heater treater temperatures; connecting storage tanks to flare systems; converting gas-driven chemical pumps to electric-, air- or nitrogen-driven pumps; compressing casing gas and shutting down line pigging. Also, air emission may be decreased by installing: no-bleed or low-bleed pneumatic devices; vapor recovery units; high efficiency flares; closed-loop skimmers on water tanks; and separator pumps and evacuators on pipeline bleeders.[355]
- Wellhead compressors that are powered by natural gas emit NO_x and VOCs (which contribute to ground-level ozone) and carbon monoxide. According to the federal Bureau of Land Management, there are add-on technologies, such as catalytic converters, that can reduce these emissions by as much as 95%.[356]
- Cavitation baffle systems (large storm sewer concrete pipe) can be used to reduce flare height and contain the majority of coal dust during coalbed methane cavitation operations.[357]

- Barrett Resources Corporation has minimized odors generated at natural gas production sites, a common source of complaint by surface owners, by using combustion units designed to destroy vapors released by condensate tanks and glycol dehydrators. These units also reduce emissions of methane (a greenhouse gas), and other hydrocarbons that can affect visibility.

Capture Gas Instead of Flaring It

The federal Department of Energy and the Interstate Oil and Gas Compact Commission are involved in a project to reduce greenhouse gases and NO_X emissions and increase oil production and in California. Gas that would otherwise be flared, and shut-in gas from California's oil-fields will be used to generate electricity. Several types of conventional and new microturbine generators will be tested at selected sites from among California's 21,000 marginal wells.

Petroleum Technology Transfer Council[358]

- Standard glycol dehydrators which are used to remove water from natural gas, typically vent water and hazardous gases directly into the atmosphere. Glycol dehydrators are a major source of benzene emissions within the oil and gas industry.[359] Fatalities from human exposure to high concentrations of benzene have been documented since the early 1900s, and studies have shown correlations between workplace exposure to benzene and the onset of certain forms of leukemia.[360] The issue of air emissions from glycol dehydrators has only been identified in the past few years. Most of the glycol dehydration units are installed in rural environments; they are typically left unattended, and emissions are not regularly monitored.

  In 1995, the Canadian government announced that it would be limiting benzene releases through various measures including controlling emissions of benzene from natural gas dehydrators. A Canadian Working Group composed of industry, government, and public interest groups produced a document, *Best Management Practices for Control of Benzene Emissions from Glycol Dehydrators*,[361] which outlines methods for minimizing benzene emissions in new and existing plants; and provides more information on alternatives to glycol dehydration. These include: methanol or glycol injection; separator packages; line heaters; solid desiccant/molecular sieve plants; membrane technology; and other commercial processes.

  Emissions from glycol dehydrators can be reduced by: optimization of operations; equipment modifications or replacement; and/or, addition of emission control equipment. Emission controls such as condensers, flare stacks, and incinerators for still column vent vapors have been installed by industry at some locations. Research by the U.S. EPA has indicated that operators of glycol dehydrators often maintain a circulation rate that is at least two times higher than is needed to remove enough water from the gas. Therefore, companies can reduce their glycol use by performing simple calculations to determine the minimum circulation rate needed. By doing so, they will lose less methane to the atmosphere; improve the dehydrator unit efficiency; and decrease fuel pump use. EPA has calculated that by doing so, the potential savings for a dehydrator unit can range from $260 to $26,280 per year.[362]