# Paper #2-26

# LIFE CYCLE OF ONSHORE OIL AND GAS OPERATIONS

Prepared by the Onshore Operations Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

**These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.**

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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# LIFE CYCLE OF OIL AND GAS

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# Life Cycle of Oil and Gas[1]

## 1. Introduction to Life Cycle of Oil and Gas

This document provides a high level overview of the life cycle of onshore oil and gas from undisturbed ground prior to exploration or drilling, through reclamation and abandonment of a location, and follows the produced oil, gas and liquids up to refining and transportation of products. The processes in the life cycle of oil and gas exploration and production that influence the environment, and how different environments, particularly the arctic, require different processes, are described.

The phases of the life cycle of oil and gas addressed in this document are:

- Exploration, seismic and planning (includes operational permitting, planning, and approvals)
- Construction and interim reclamation (pads, roads, etc.)
- Drilling
- Completions and workovers
- Field production
- Surface equipment (facilities, gathering, compression, treating)
- Gas plant operations
- Transportation, pipelines and storage
- Abandonment and final reclamation
- Health and safety of workers and personnel management and work force facilities

## 2. Exploration, Seismic, Leasing, Permitting, and Planning

Exploration is the first stage for any company considering drilling in an area. Since there is no way to be absolutely certain where new oil and natural gas reservoirs are located, companies use technology to help pinpoint these potential resources with ever improving accuracy. Exploration operations often begin with geologic evaluation to identify underground geologic structures where oil and gas may have accumulated. This can result in drilling fewer wells and lowered exploration costs. Information on potential geological formations and oil and gas seeps is collected above-ground by mapping the surface. More exact information is collected by assessing geological structures and sub-surface rock properties.

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[1] Documents relied upon in the generation of this section are: 1) American Petroleum Institute (API). February 1997. "Environmental Guidance Document: Waste Management in Exploration and Production Operations." API Bulletin E5, Second Edition; 2) La Plata County Energy Council. "Gas Facts, Production Overview." Accessed April 2011 at http://energycouncil.org/gasfacts/prodover.htm; 3) API. "Adventures in Energy: Oil and Natural Gas, from the Well to You." Accessed April 2011 at http://www.adventuresinenergy.com/index.html; 4) Natural Gas Supply Association, NaturalGas.org. "Natural Gas: From Wellhead to Burner Tip." Accessed April 2011 at http://www.naturalgas.org/naturalgas/naturalgas.asp.

Many of these technologies can be used to explore additional untapped accumulations in existing fields or to optimize well location and type based on the characteristics of the field. From these technologies and other improvements in the industry, the drilling success rate has improved from 75 percent successful wells a decade ago to 90 percent success as of 2009.[2]

### 2.1. Geologic Evaluation

Understanding the geology of an area is essential to knowing if a petroleum system is present. Three components must be in place for a petroleum system: a source of hydrocarbons, a reservoir to hold the oil and gas, and a trap or seal to keep the hydrocarbons in place. Geologists use several methods to evaluate the potential for areas to have these three key elements.

The first step often used is to research prior work and knowledge. Often times, fields were initially bypassed due to the perceived lack of commercially recoverable hydrocarbon accumulations, or the inability of an operator to get the oil or gas to flow. With the new drilling and hydraulic fracturing techniques and better understanding of these 'unconventional' plays, this significant quantity of hydrocarbons may be commercially recoverable.

The development and use of computer technology has revolutionized hydrocarbon exploration and development over the past 50 years. Software for data management, document management, geoscience and reservoir engineering allows more efficient exploration, production and regulation through proper tracking, integration, analysis and reporting of information. Geographic information system (GIS) software allows easy integration, analysis and display of information that can be combined and presented in map form (e.g., well locations, oil accumulation outlines, political boundaries, roads, pipelines, environmental data). Old data can be re-scaled and combined with more recent information to yield new insights and improve interpretations. Data can now be obtained easily from world-wide sources through the Internet. All of these technologies benefit exploration and production activities, particularly in the arctic, by making data gathering and analysis more efficient and cost-effective.

Once this review is complete, the rocks are studied at various scales, such as outcrop and cuttings and core from nearby wells or wells drilled into similar formations. The rock and fluid properties, such as porosity, permeability, and hydrocarbon type and content, are evaluated using wireline logs, core analysis, and well tests. From these data, maps and cross sections can be made to identify key potential zones of interest. Numerous types of technology exist to aid in this exploration, helping geologists locate productive intervals, which are explained in further detail in the following sections.

#### 2.1.1. Gravity and Geomagnetic Surveys

These relatively inexpensive techniques can identify anomalies in rocks, which may indicate potential oil and natural gas bearing sedimentary basins and structures. Gravity surveys work by measuring the differences in gravitational attraction between points of measurement, providing indications of density anomalies. These surveys can be taken

[2] Godec, M. C., 2009, Environmental Performance of the Exploration and Production Industry: Past, Present, and Future: SPE Paper 120918, pp. 12.

from terrestrial locations, while airborne, from ships at sea, or in a wellbore.[3] High-resolution aero-magnetic surveys done by special aircraft can show fault traces and differentiate between different rock types near the surface. These surveys work by measuring the total intensity of the earth's magnetic field, and after processing can provide an idea of local anomalies. Due to the lack of magnetic minerals typically found in sedimentary rocks, this survey type has limited applicability.[4]

#### 2.1.2. Seismic Surveys

Seismic surveys are used to evaluate properties of rock below the surface of the earth using the reflection of sound waves. The surveys are done by transmitting acoustic energy into the earth and measuring the time it takes for the energy to be reflected by changes in rock properties back to the surface where it is measured and recorded. The work activities associated with seismic surveys are: access to the area of interest; construction of seismic lines; and construction and maintenance of a base camp (as necessary). Seismic lines are constructed by clearing a 3 to 6 foot wide path.

The acoustic energy can be generated using several different methods, including explosive charges. With this method, shallow holes are typically drilled along the seismic line and explosives used. Most seismic crews use non-explosive seismic technology to generate the required data. This non-explosive technology can consist of large heavy wheeled or tracked vehicles with a piston in the middle designed to create a series of vibrations. These vibrations create the necessary acoustic energy to evaluate the characteristics of the rock in the area of interest. The illustration below shows a "vibrator truck" originating the sound wave (Figure 1).[5] Note that the geologic conditions dictate type of energy source required – non-explosive is not always suitable.

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[3] LaFehr, T.R., 1992. "The Gravity Method." *in* Development Geology Reference Manual: AAPG Methods in Exploration Series, No. 10, eds. D. Morton-Thompson and A. M. Woods, pp. 411-412.
[4] Reford, Michael S. 1992. "Magnetics" *in* Development Geology Reference Manual: AAPG Methods in Exploration Series, No. 10, eds. D. Morton-Thompson and A. M. Woods, pp. 415-416.
[5] Heavy Oil Seismic Center. "Seismic Operations: A Backgrounder." Accessed April 2011 at http://www.lloydminsterheavyoil.com/seismic.htm.

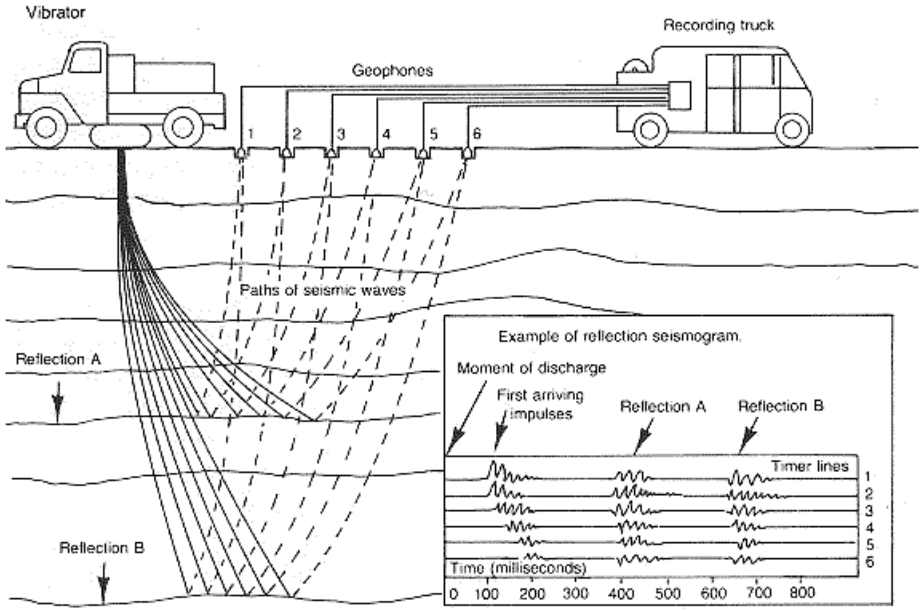


Figure 1. Seismic survey using a vibrator truck. Source: Heavy Oil Science Centre, Seismic Operations: A Backgrounder

Early exploration work on the North Slope was conducted utilizing conventional wheeled and tracked vehicles. This proved to be very damaging to the tundra, even when travel was done in the winter months when the tundra was frozen, and resulted in serious long term impacts to the tundra and the underlying permafrost. In the 1960s, Rolligons, truck-like vehicles with very large, balloon-like tires to spread the weight over a larger area, were developed and have been used extensively on the North Slope since to minimize impacts to the tundra. Utilizing Rolligons allows operators to carry substantial loads across the tundra leaving virtually no tracks and access remote sites sooner and stay on them longer than if they had to wait until an ice road could be built to support conventional vehicle traffic. To further protect the tundra, such operations are conducted only in the winter when the ground is frozen solid and wildlife is absent.[6]

The recorded seismic data are then processed using specialized software and seismic profiles are created. From these profiles, it is possible to generate maps and look for features in the rock indicating the presence of hydrocarbon accumulations. While seismic data are extremely useful to geologists and development teams, these surveys are also very expensive.[7]

A number of types of seismic exist. 2D seismic is obtained by acquiring data through a single line of receivers from a single line of sources. 3D seismic uses a grid of receivers with a grid of sources. 4D adds a time component by obtaining multiple 3D surveys of the same area at different times.

[6]API. "About Oil and Gas, New Technology Minimizes Impact of Arctic Operations." Accessed April 2011 at www.api.org/aboutoilgas/sectors/explore/newtechnology.cfm.
[7] API. "Adventures in Energy: Exploration and Production." Accessed April 2011 at http://www.adventuresinenergy.com/Exploration-and-Production/Exploration.html.

Seismic data may also be collected after a well has been drilled. Vertical seismic profiles are generated using a surface seismic source, such as a vibrator or an air-gun that is fired into a tank of water, and sound detectors (geophones) that are lowered down a well. Seismic signals collected down the well allow drilled rock strata to be accurately related to nearby seismic data (seismic lines). Knowing which rock layers correspond to features on seismic lines allows geoscientists to more accurately understand subsurface geology and hydrocarbon accumulations. In a drilling program, seismic surveys can be used to identify the drilling path and avoid drilling hazards.

Once a reservoir has been located and put into production, a series of 3-D or 4-D seismic surveys can be taken over time to see if all of the oil and natural gas reserves are being efficiently drained and to identify flow patterns of the hydrocarbons. If not being effectively drained, additional wells can be drilled to produce these bypassed pockets of reserves. Due to advances in processing technology, the 3D seismic images have increased the drilling success rate (effectively reducing the number of wells drilled)[8] and it is now often feasible to reprocess old seismic data, allowing reinterpretation of data without the cost and footprint of a new survey.[9]

### 2.1.3. Geochemical Surveys

The presence of hydrocarbons at the surface or near surface of the ground has been linked to "hydrocarbon microseepage" from underground reservoirs.[10] Geochemical surveys look for these chemically identifiable surface or shallow subsurface indications of petroleum or hydrocarbon related products in small holes ranging from a few inches to feet. The presence of these compounds can indicate the existence of oil and gas accumulations in the area being evaluated. Direct measurement of hydrocarbons that have migrated to the surface through seepage from leaky reservoirs can be taken from soil pore space. Indirect measurement looks for changes in the soil, sediment, or vegetation due to microbial activity on the hydrocarbons or the presence of minerals due to changes in the oxidation states of the soil.[11]

There is a very limited environmental footprint for this method, typically only a few small holes ranging from inches to feet. However, the technique is limited in application due to the complexities of geochemical anomalies and is best used in conjunction with other methods such as seismic. When used with other technologies, it can increase the

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[8] API. "About Oil and Gas, New Technology Minimizes Impact of Arctic Operations." Accessed April 2011 at www.api.org/aboutoilgas/sectors/explore/newtechnology.cfm.

[9] API. Exploration and Production Website: http://www.api.org/ehs/performance/explore/moreexplorproduction.cfm.

[10] Saunders, Donald F., K. Ray Burson, and C. Keith Thompson. 1999. "Model for hydrocarbon microseepage and related near-surface alterations." *AAPG Bulletin* 83 (Jan): 170 - 185. Summary accessed April 2011 at http://aapgbull.geoscienceworld.org/cgi/content/abstract/83/1/170

[11] Schumacher, D. 1999. "Surface geochemical exploration for petroleum." In *Exploring for Oil and Gas Traps: Treatise of Petroleum Geology, Handbook of Petroleum Geology*, E.A. Beaumont and N.F. Foster, eds., p. 18-1 to 18-27. AAPG.

probability of success in certain settings,[12] and it can be applied on producing fields to better define the areal extent or to locate bypassed resource potential in historical areas.[13]

### 2.2. Exploratory Wells

An exploration well is often drilled when the geologic data indicate a likely site for oil and natural gas resources. Rock samples from the well are brought to the surface and analyzed and well logs measure the electrical, magnetic and naturally radioactive properties of the rocks. By examining this information, a geologist can learn a great deal about the sub-surface structures and whether or not the site is likely to produce oil and natural gas in economic quantities.[14]

In addition to looking for natural gas and petroleum deposits by drilling an exploratory well, geologists also examine the drill cuttings and fluids to gain a better understanding of the geologic attributes of the area. Drilling an exploratory well is an expensive, time consuming effort; such wells are typically drilled in areas where other data has indicated a high probability of petroleum formations.

Historically, these exploration wells or wildcats were literally a shot in dark - holes drilled with little data, relying largely on luck. With the new technological advances in exploration techniques, like the 3D seismic surveys discussed above, these wildcat wells have a much higher rate of success. This is a benefit to the operator as well as the environment.[15]

### 2.3. Resource Leasing, Permitting and Approvals

Federal, provincial, state, tribal, and local permits can be required to drill and produce oil and gas wells. During the permit process, environmental, archaeological and surface use issues are addressed. Operators are expected to adhere to hundreds of regulations and meet a wide range of standards and requirements before the drilling begins. Rules require companies to plan for the entire life of the well, unexpected events, safety, environmental protection, weed control and final reclamation when the production cycle is completed. Only when all requirements are met and permits granted should an operator begin to drill.

Development of federally owned oil and gas resources in the US is regulated by several federal laws and associated regulations, including:

- Leasing of federal resources is regulated primarily under the Mineral Leasing Act of 1920 (MLA) as amended by the Federal Onshore Oil and Gas Leasing Reform Act of 1987 (FOOGLRA); and
- Environmental impacts of development are regulated through: federal agency organic acts like the Federal Land Policy and Management Act (FLPMA) and the

[12] Saunders, et al. 1999.
[13] See, for example, W. L. Gore & Associates, Inc., Geochemical Services, Onshore Petroleum Exploration Survey Brochure. Accessed April 2011 at http://www.gore.com/en_xx/products/geochemical/petroleum/onshore_brochure.html.
[14] "Adventures in Energy", API, at http://www.adventuresinenergy.com/Exploration-and-Production/Exploration.html.
[15] API, New Technology Minimizes Impact of Arctic Operations www.api.org/aboutoilgas/sectors/explore/newtechnology.cfm.

National Forest Management Act (NFMA); and national environmental laws like the Clean Air Act, Clean Water Act and Endangered Species Act.

The U.S. federal agencies involved in energy resource development on federally controlled land are mostly in the Department of the Interior (DOI) and include:

- The Bureau of Land Management (BLM) is the main federal agency responsible for regulating development of non-renewable, federally-owned energy resources. The BLM is responsible for leasing federal oil and gas, coal, and geothermal minerals, and for supervising the exploration, development and production operations for these resources on both federal and Indian lands.
- The U.S. Forest Service (USFS), U.S. Fish and Wildlife Service (USFWS), and National Park Service (NPS) are other DOI land management agencies that participate in leasing and development decisions.
- The Revenue Management Program (MRM), part of the DOI Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), collects, accounts for and distributes revenues associated with oil, gas, mineral production from leased federal and Indian land.
- Although the Bureau of Indian Affairs (BIA) issues mineral leases on Indian lands, the BLM approves and supervises mineral operations on these lands. The BIA manages oil and gas revenues for tribal members with Individual Indian Money (IIM) accounts.
- The Environmental Protection Agency (EPA) is responsible for implementing federal environmental acts, such as the Clean Water Act and Clean Air Act, to control impacts of oil and gas development. The EPA also manages the National Environmental Policy Act, which required federal agencies to make decisions with consideration of the environment. This is accomplished through an Environmental Impact Statement; a document prepared by other federal agencies, and reviewed and filed by the EPA.[16]

State and local laws and regulations also regulate oil and gas development on federal, state and privately-owned lands. State laws and regulations can control the location of exploration and production facilities and the environmental impacts of development. The role of local ordinances varies from state to state. As oil and gas development has accelerated in recent years, some states have responded with stricter regulations requiring broader public participation in leasing decisions.

In Canada, the provinces take the lead in oil and gas oversight, including leasing the rights, setting and collecting royalties, and protecting the environment.[17] The permitting and approvals process for oil and gas development is very extensive and is covered in its entirety in the Environmental and Regulatory Framework document. Specifically, the

[16] EPA. National Environmental Policy Act Website. Accessed April 2011 at http://www.epa.gov/compliance/nepa/.
[17] Government of Alberta, Environment. March 2008. *Alberta's Oil Sands: Opportunity, Balance*. ISBN 978-07785-7348-7. Accessed April 2011 at http://www.environment.alberta.ca/documents/Oil_Sands_Opportunity_Balance.pdf.

topics covered include the federal process, provincial processes, tribal process, state and local process, and the permitting associated with potential environmental impacts.

#### 2.3.1. Federal Leasing

Federally owned oil, gas, coal, coalbed methane, and oil shale are all "leasable" minerals, and the company that gets the rights may be referred to as the lessee. The BLM has discretion to lease these minerals, generating revenue for the states, tribes and federal government. The MLA does not specifically mention coalbed natural gas, but it is generally leased as part of the gas resource. All these minerals were originally "locatable" minerals, developed for free on federal lands under the General Mining Law of 1872. The MLA removed the energy minerals (coal, oil, oil shale, gilsonite and gas) from the "free access" rule of the 1872 Mining Law.

#### 2.3.2. Revenue Sharing

Companies and lessees pay for development of public energy resources on federal oil and gas leases, including royalty, rentals, and bonus payments. For oil and gas leases through the BLM, half of this money goes to the states and half goes to the U.S. Treasury. The states can use this money without restriction.

#### 2.3.3. Mineral Rights on State and Private Lands

The DOI estimates that approximately one third of America's energy comes from land managed by the DOI.[18] The balance resides on state lands and private property. As explained below, this may involve separate arrangements for access to the surface and to the oil and gas underground.

Companies must secure permission from the owner of the mineral rights, whether the owner is a private citizen or the state or federal government. Many mineral rights owners and the government allow oil and natural gas companies to compete to drill on their land. The companies assume all the costs and risks of drilling and pay the mineral owners a portion of what they find and a signing bonus to secure the drilling rights. The share of the production paid by the company to the mineral owner is called a royalty payment.

Individual landowners that own both the surface and mineral rights typically negotiate a private agreement with an oil or gas company that is interested in exploring for and possibly producing petroleum on their property. These agreements are known as "oil or gas leases" and typically extend for a period of several years. Landowners are often compensated by receiving rental fees for the number of acres in the lease and a percent royalty payment on the value of the oil or gas produced.

#### 2.3.4. Split Estates

A split estate exists when the surface landowner does not own all of the minerals under the property. This can be a major source of conflict with the surface land owner when they do not own the minerals, yet the mineral estate is considered dominant and takes precedence over their surface rights.

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[18] U.S. Department of the Interior (U.S. DOI), Bureau of Land Management (BLM). 2004. *American Energy for America's Future, The Role of the U.S. Department of the Interior*. p. 3. Accessed April 2011 at http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_.Par.61407.File.dat/EnergyBro.pdf.

The owner of land traditionally controlled use of the land from the heavens to the center of the earth. Congress changed this so that land ownership can be horizontally divided into surface and subsurface (mineral) estates. For example, under the homesteading laws, the federal government kept the mineral rights when granting the surface land. The mineral estate can be further subdivided by minerals—the oil, gas and coal owners can all be different.

The three important types of split estates in oil and gas development are:

- The federal government owns only the surface and the mineral rights are owned by the state or a private entity;
- The federal government owns only the minerals and the surface is state/private owned; or
- Different state or private owners own both the surface and minerals.

The Energy Policy Act of 2005 required DOI to review current policies and practices for federal oil and gas development on lands involving private or state surface ownership overlying federally owned minerals. The DOI report was published in December 2006 and:

- Compared the rights and responsibilities of DOI, the federal lease holder (company or developer) and private landowners;
- Compared surface owner consent requirements for oil and gas development with the more restrictive requirements for federal coal development; and
- Made recommendations of legislative and administrative changes necessary to balance reasonable access for development with surface impacts and owner concerns.

(See BLM's Split Estates web page.[19])

A private landowner that only owns the surface does not have the right to develop the minerals and, in most cases, does not have the right to prevent development. Companies are generally willing to pay surface owners for limited land use even though the law permits reasonable access and use without compensation.

Before developing the oil and gas, under most circumstances of a split estate, the mineral owner or the lessee of the mineral rights must either get written consent, a waiver from the landowner (a surface use agreement), or pay an agreed-upon amount for damages for the reasonable use of the surface during drilling, production and reclamation of the well site. Certain state agencies may require the oil and gas companies to consult with the surface owner about the locations of well sites and access roads and final reclamation. If a surface agreement cannot be successfully negotiated, federal and state regulations often allow companies to post a surface bond.[20] The bond is intended to protect surface owners

[19] U.S. DOI, BLM, Split Estates. Accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/split_estate.html.

[20] See DOI's Instruction Memorandum No. 2003-131, *Permitting Oil and Gas on Split Estate Lands and Guidance for Onshore Oil and Gas Order No. 1*, April 2, 2003. Accessed April 2011 at http://www.blm.gov/pgdata/etc/medialib/blm/mt/blm_programs/energy/oil_and_gas/policy.Par.90285.File.dat/03wom131.pdf; and, e.g., Colorado Oil and Gas Conservation Commission rules, 700 Series: Financial

from unreasonable crop losses or land damage from the use of the premises, but not for perceived economic loss associated with mineral owner access.

### 2.3.5. Cultural Resources on Split Estates

The definition of cultural resources from the BLM is, "a definite location of human activity, occupation, or use." When leasing development of federal minerals, the BLM is required to determine if approving a specific site for oil and gas development will have an effect on cultural resources, even if they are located on private surface. Typically, an on the ground survey is conducted, by professionally trained archaeologists, to accurately identify any cultural resources. If artifacts are found, they are removed and either remains with the surface owner or is sent to a museum. The state's role in this process may vary by state, but the State Historic Preservation Office is to maintain records of where cultural surveys have been conducted.[21]

### 2.3.6. Good Neighbor Agreements

Good Neighbor Agreements (GNAs) are based on the philosophy of mutual acknowledgement between a business and the independent community in which the business operates. A GNA recognizes the needs of each party through building an understanding relationship. These agreements are flexible with the base of the agreement focusing on protecting the environment and the community where the business is operating and the community resides. Although not all GNAs are legally binding, they are formally negotiated and can be part of a permitting process (see, Civic Practices Network, Good Neighbor Agreements, at http://www.cpn.org/topics/environment/goodneighbor.html).

Such agreements have been used primarily in fields such as petrochemicals, but can also be used for oil and gas well field development. GNAs typically are done before a crisis, and promise company concessions and behavioral changes designed to reduce and disclose negative community impacts in exchange for community group commitments to forego permit challenges, lawsuits, negative publicity campaigns, and other forms of activism against the company. A state industry group and a national oil and gas group have adopted guidelines to encourage the companies to include good relationships with communities in their development plans.[22]

### 2.3.7. Energy Right of Way Corridors

Rights-of-way (ROWs) easements for oil and gas development, such as access roads, are negotiated with the state or private surface owners. Rights-of-way on federal lands are generally authorized through special use permits issued by the land management agencies. A ROW grant authorizes the use of a specific piece of public land for specific

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Assurance and Environmental Response Fund, April 2009. Accessed April 2011 at http://cogcc.state.co.us/.

[21] BLM. 2008. *Split Estate: Cultural Resource Requirements on Private Surface - Federal Minerals for Oil and Gas Development*. Accessed April 2011 at http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/bmps.Par.98100.File.dat/SplitEstate08finalWeb.pdf.

[22] New Mexico Oil and Gas Association (NMOGA), www.NMOGA.org, and API, Policy Issues, Environmental Impact, *Considering Good Neighbor Practices* (2008). Accessed April 2011 at www.api.org/policy/exploration/upload/Good_Neighbor_Guidelines.pdf.

facilities for a specific period of time. Most BLM ROWs are issued pursuant to Title V of FLPMA (43 U.S.C. 1761-1771) and pursuant to the Mineral Leasing Act for oil and natural gas gathering and transmission pipelines. The Energy Policy Act of 2005, section 368, requires DOI to consult with several other departments and entities to designate corridors for oil, gas and hydrogen pipelines and electricity transmission and distribution facilities on federal lands in the eleven western states. These entities must also perform the necessary NEPA evaluations and incorporate the corridors into appropriate land use plans. (See the BLM's Lands and Realty information, http://www.blm.gov/ut/st/en/fo/kanab/more_/lands_realty.html, for detailed information on BLM ROWs.) Negotiations for pipeline easements are typically negotiated after a successful well has been completed.

### 2.4. Planning

The impacts of oil and gas development along with technologies and operational practices that avoid, minimize, or mitigate those impacts are addressed in further detail in other papers associated with this document.

#### 2.4.1. Site Selection and Design

After the geologic and seismic studies are completed, companies typically select an optimal site. Well location and right-of-way easements for road access are negotiated with the surface owners. During this phase, companies work closely with surface owners to locate the well site within the regulated spacing “window.” A window determines the underground area within a spaced unit where a well may be drilled and is specified by the state oil and gas agency. Sometimes a gas well is located outside the window when special circumstances arise such as above ground geography or a special landowner request.[23]

When done properly, well site selection is based on the ability of the location to fit the landscape and minimize construction needs and long term disruption of the surface and existing uses. Also, site selection should take into consideration interim and final reclamation, being sure that the site has the potential for successful remediation. Methods for achieving these selection criteria include:

- Designing an irregularly shaped pad (not necessarily rectangular) to fit the landscape;
- Placing the pad on existing level terrain, avoiding narrow ridges and steep slopes. This reduces the need for vertical cuts and steep fill slopes;
- Avoiding riparian zones, floodplains, wetlands, playas, and lakeshores to prevent soil movement and erosion and to minimize wildlife impacts; and
- Using topographic screening in visually sensitive areas.

In some situations, the above issues may be unavoidable due to geologic target, well spacing, or technology, and therefore appropriate mitigation procedures based on specific location characteristics are developed with the applicable land management agencies.

[23] See, e.g., La Plata County Energy Council, Gas Facts: Production Overview, accessed April 2011 at http://energycouncil.org/gasfacts/prodover.htm#gas.

### 2.4.2. Habitat Management and Mitigation

Oil and gas resources may accumulate under areas of sensitive wildlife habitat. These areas may also be opened to exploration and production of these resources, creating the need for careful management and mitigation planning.[24] The process begins with site surveys to identify potential habitat and aquatic areas that are important to sensitive species. For example in the western United States, temporal restrictions exist to protect winter range, mating grounds, and other important locations for species. Oil and natural gas companies work with local and federal wildlife officials to minimize activities in sensitive areas during sensitive time periods.

Specifically during design and construction, a number of actions can be taken to reduce the potential impacts to sensitive habitat and aquatic areas. Erosion control is important and can include increasing berm sizes on slopes that drain directly into waterway, using mulch or armoring on slopes, and ensuring that interim reclamation is done quickly, effectively, and using the appropriate seeds for the area. In addition, to protect both wildlife and humans, fencing, netting and flagging is often put in place around pads or pits to deter the use by animals.

### 2.4.3. Stormwater Management

Stormwater is rainwater and melted snow that runs off roads and other sites, or naturally soaks into the ground. Stormwater management is typically required throughout the life cycle of the well, but is most successful in avoiding environmental impacts when designed prior to any earthmoving. The stormwater management design is based on the specific characteristics of each location, with the goal being prevention of stormwater runoff impacting the surrounding areas or United States Waters. Stormwater, in many cases, is diverted away from the well location using ditches, berms, or waterbars above cut slopes to prevent erosion and soil loss. The well location runoff and associated sediment is trapped or diverted using sediment fences or water retention ponds to prevent the runoff of fugitive pollutants into streams, rivers, and lakes. Additional best management practices (BMPs) exist and are used based on the specifics of each location (see the Natural Resources Law Center, Intermountain Oil and Gas BMP project: http://www.oilandgasbmps.org/ or the EPA's Stormwater Management Best Practices at http://www.epa.gov/greeningepa/stormwater/best_practices.htm).

The pads, man-made islands, and platforms used for oil and gas exploration and development in Alaska are designed to be zero-discharge facilities. The facilities are designed in such a way that any fluid that spills onto the work surface, including rainwater and snow melt, will flow to collection sumps where the fluids will be collected and can be pumped into a disposal well or, if appropriate and approved, into an injection well used for enhanced oil recovery (EOR) service. This reduces the potential for these fluids to be able to get onto the tundra or to enter the seawater.

### 2.4.4. Reclamation Planning

Reclamation is the process of returning or restoring the surface of disturbed land as nearly as practicable to its condition prior to the commencement of oil and gas operations

[24] See, e.g., oil development in the St. Charles Field at the Aransas National Wildlife Refuge in Texas, winter grounds for the whooping cranes.

or to landowner specifications. Reclamation helps ensure that the effects of oil and gas development on the land and on other resources and uses are only temporary. For best results, reclamation should begin prior to construction. On federal lands, a reclamation plan is included in the surface use plan for the operations, which must be approved before any construction can begin. The BLM has both requirements and recommendations for reclamation and how to minimize the impact requiring reclamation.[25]

The ultimate objective of reclamation is ecosystem restoration, including restoration of the natural vegetation community, hydrology, and wildlife habitats. In most cases, this means a condition equal to or closely approximating that which existed before the land was disturbed. Reclamation must achieve short-term stability, the visual, hydrological and productivity objectives of the surface management agency, and include the steps necessary to ensure that long-term objectives will be reached through natural processes. Reclamation restores the original landform or creates a landform that blends in with the surrounding landform. Successful reclamation allows local native species to re-establish on the site and area to regain its original productive and scenic potential. Reclamation is successful when a self-sustaining, vigorous, diverse, native plant community is established, with a density that will control erosion and non-native plant invasion, and re-establish wildlife habitat or forage production.[26]

Integrating reclamation into operations in this way is critical to successful reclamation. The scale of reclamation will vary depending on the size of the operation and the future interest of developing the area, but the process of reclamation must begin as soon as possible after the surface is disturbed and continues until the appropriate regulatory agency determines that successful reclamation has been achieved. Partial reclamation of drilling areas, known as interim reclamation, must occur on federal lands prior to or during production. Minimizing surface disturbance during construction can reduce the amount of final reclamation required.[27]

### 2.4.5. Community and Surface Owner Outreach and Communications

A significant aspect in the planning process for oil and gas development is the consideration of the communities in which the industry operates. Whether operations are taking place in or near urban areas or in sparsely populated regions such as Wyoming or Alaska, community considerations and potential beneficial and negative impacts are outlined and considered in the planning process based upon each individual location. As discussed above, a state industry group and a national oil and gas group have adopted guidelines to encourage the companies to include good relationships with communities in

[25] BLM, Reclamation and Abandonment, accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/leasing_of_onshore/og_reclamation.html, and BLM, Best Management Practices, Technical Information, accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/technical_information.html.

[26] BLM, Reclamation and Abandonment, accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/leasing_of_onshore/og_reclamation.html.

[27] Ibid.

their development plans.[28] There are other examples of local industry groups reaching out to the community and making information available through meetings and websites.[29]

## 3. Construction

Construction associated with oil and gas development is based on the needs of the location and phase of development at the site. For example, a location not in close proximity to other development may require additional facilities. As discussed above under Site Selection, the actual site for construction will depend on many factors, not only the location of the oil and gas.

The BLM publication *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development*[30] (commonly referred to as the "BLM Gold Book") was developed to assist companies (operators) by providing information on the requirements for obtaining permit approval and conducting environmentally responsible oil and gas operations on federal lands and on private surface over federal minerals (split-estate). This includes the construction activities discussed below. The BLM website also includes BMPs on construction and reclamation.[31] Other requirements may exist at the state or local levels.

### 3.1. Pad and Pit Construction

Typically, individual drilling pad locations range in size from one to five acres. A certain amount of space is required to separate the drilling rig and wellhead from surrounding wildlife, crops or residences. In addition, the well pad must be large enough to accommodate emergency equipment, should it ever be necessary.

The main objectives with pad construction are to create a level pad with compacted soil to support the drill rig and additional production equipment that will be in place upon completion of drilling operations. The well pad and surrounding area must also accommodate the support equipment. This is the term applied to all the equipment needed in the field for personnel, and various maintenance and construction equipment necessary for smooth operations and repairs during the life of the well. This may include drilling fluid storage, electric power generators, fuel tanks, pipe racks, maintenance and emergency equipment storage, and personnel shelters or quarters. The drilling fluid storage equipment, generators, and fuel tanks ideally should be on a slight slope or properly drained by ditching from the work area to the pit. Equipment on location for earthmoving is appropriately sized for the scale of the job.

Pits or reserve pits are designed to contain all anticipated drilling fluids, cuttings, fracture fluids, and precipitation with at least two feet of freeboard at all times. Reserve pits are placed in a position to avoid shallow groundwater and natural watercourses such as lakes

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[28] New Mexico Oil and Gas Association (NMOGA), www.NMOGA.org, and API, *Considering Good Neighbor Practices,* at www.api.org/policy/exploration/upload/Good_Neighbor_Guidelines.pdf.
[29] See, e.g., La Plata County Energy Council, at http://energycouncil.org/index.htm.
[30] United States DOI and United States Department of Agriculture, 2007, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development. BLM/WO/ST-06/021+3071/REV 07. BLM. Denver, Colorado. 84 pp. Accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/gold_book.html.
[31] BLM. Oil and Gas, Best Management Practices, accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html.

beds, gullies, draws, streambeds, arroyos, washes, or channels, as marked on a 1:24,000 United States Geological Survey quadrangle map. The pits should be dug completely into cut material.

On sloping sites, reserve pits are typically built next to the high walls of the slope cut. Ideally, the pit should be entirely below the original ground level in cut material, but if that is not possible, at least 50 percent of the pit should be in cut.

Pits are typically lined with synthetic liners or clay, such as bentonite. Consideration is given to ensure that the pit liner is compatible with all the substances to be placed in the pit and is installed properly to prevent leaks. Clay is used in situations where the bedrock is sharp enough to puncture the liner. Additional precautions may be taken such as fencing and other wildlife deterrents. Fencing also prevents human access to the pit. Further information on the use of pits is found in the section below on reserve pits.

### 3.2. Road Construction

Roads are designed to meet the appropriate standard required to accommodate the intended use. Roads for oil and gas access can be temporary and exist only as long as required for exploration and production operations. New road construction allowing access to oil and gas operations can become public roads for recreational access and may need to be constructed with safety in mind specifically for those not familiar with the area.

Numerous criteria are used for selecting the optimal access to a location for both the operator and environment. The following list includes some of the criteria considered to reduce impacts to cultural, scenic, biological and other environmental resources: soil types, construction and reclamation limitations, type of excavation required, landslide potential, sub-grade conditions requiring surfacing of the road, cut slope problems, suitability of fill material, potential gravel pits or quarries for aggregate, and borrow and waste sites such as for snow removal. Additional factors to consider are evacuation routes, local weather patterns (monsoons or heavy snowfall), and future development potential if the road is accessing an exploratory location.

Following topography rather than minimizing length can be a positive operating practice in road construction. Minimizing road length can result in erosion, loss of vegetation in the long term, and poor visual quality. Contouring can maintain natural drainages and lower maintenance and reclamation effort and costs.

The BLM and the USFS have design requirements for roads as listed below.[32] Designs may vary due to the unique nature of many of the areas in which oil and gas operations occur, for example:

- The speed limit does not exceed 30 miles per hour for BLM and 15 miles per hour for USFS;

[32] BLM Gold Book at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/gold_book.html, and BLM BMPs at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/technical_information.html.

- Width of the road is ideally 14 feet with turnouts, which should be placed every 1,000 feet or be visible from one to the next (intervisible), whichever is less;
- The road gradient should fit the natural terrain, however not exceed eight percent for more than 300 feet unless prior authorization is received;
- Drainage control must be built into the road design, with culverts and ditches capable of at least a 25 year storm event and if bridges or culverts are necessary, the span must be at least 20 feet horizontally and may require a Section 404 Corps of Engineers permit; and
- Gravel or other surfacing should be used only when necessary such as for soft roads, steep grades, highly erodible soil, clay or all weather access.

### 3.3. Utility Access

Access of public utilities is arranged with local utility companies based upon the needs of the operator and the availability of resources. Permits and other approval processes may be required for access and use of facilities such as water sources and waste disposal. Power line access to sites requires a right of way and contract with the local power company.

### 3.4. Fuel Gas Line

The optimal location for a fuel gas line is often along a roadway. This allows easy access for maintenance operations and leak access as well as reducing the environmental footprint.

### 3.5. Exploration Construction in the Arctic

During early exploration activities on the North Slope and in the near-shore waters of the Beaufort Sea, operators would build gravel pads in order to drill exploratory wells. The pads were usually built with gravel mined from nearby river beds, or gravel islands (gravel dredged near the islands location). The pads and islands provided a stable work surface for drilling, but also proved quite damaging to the environment. The damage was caused by both the mining and dredging operations and from the loss of tundra and impacts to the seafloor and changes in the natural current flow caused by the placement of the pad or island. Companies started using ice pads onshore and ice islands offshore for exploratory drilling on the North Slope and shallow waters of the Beaufort Sea to mitigate these impacts. Ice pads can be created by scraping ice from ponds in the area and piling snow at the drill site. The operator then sprays freshwater over the ice or snow to form a smooth hard surface on which to erect the drilling rig and the other associated facilities to support the drilling activities. Ice pads allow for winter time onshore exploratory drilling and melt away the following spring or summer. This leaves virtually no impact on the tundra. Companies can place insulating mats over ice pads and use the same ice pad for more than one winter.

Arctic pad designs and sizes have also evolved. The early pads covered about 50 acres and were based on a well-to-well spacing of 110 to 120 feet to accommodate the size of the drilling rigs. The pads featured large reserve pits to store active drilling mud as well as drilling cuttings. (Although called pits, they were actually bermed areas above the tundra.) The pads were spaced about two miles apart and developed about four square miles of the reservoir. Extensive permafrost studies, streamlined drilling rig designs, and improved casing designs have allowed the well spacing to be reduced to as little as ten feet between wells. Downhole disposal of drilling wastes and larger mud storage in the drilling rigs have eliminated the need for reserve pits. Advances in directional and extended reach drilling have increased the area that may be developed for each pad. These advances have allowed the pad areas to be reduced to less than ten acres, pad spacing to be increased to over three miles, with the pads capable of developing over nine square miles of the reservoir.

Ice roads are used extensively in the winter time by conventional vehicles to allow for travel to remote locations, either exploratory sites or development operations that are not tied to the conventional road system. An ice road is created in much the same way as an ice pad and provides the same type of environmental benefit in that come spring or summer when the ice road melts there is virtually no noticeable impact to the tundra.

Year-round roads are being designed to minimize impacts to the tundra. Including making them several feet thick and including insulation panels in the base to help prevent the permafrost from freezing. Permafrost freezing will cause an unstable road and long-term damage to the tundra. When the road is no longer needed the gravel can be reclaimed and the tundra re-vegetated to return it to a healthy condition as it was prior to road construction.

Companies will try to reclaim abandoned gravel sites in the area for materials to build or expand a gravel pad or road, provided the gravel is not contaminated and is suitable for its proposed new purpose. There are many unused gravel pads, roads, and airstrips on the North Slope that were placed during early exploratory activities several decades ago. Reuse of the gravel allows for an old pad to be removed and the tundra restored and eliminates or reduces the need to excavate new gravel mines or expand existing ones. In 1988, a North Slope company proved that processed drill cuttings could be ground and used in road construction since the material was essentially identical to native gravel and surface soils. The portions of cuttings that cannot be used as gravel are ground even more finely and injected back into a subsurface formation.

## 3.6. Interim Reclamation

Interim reclamation occurs to restore vegetation and scenic and habitat resources while a well produces energy. With interim reclamation, all areas not needed for the production of oil and gas are reclaimed, a process involving, reshaping, covering with topsoil, and reseeding the location with native plants. The revegetation during interim reclamation helps to stabilize locations, reducing potential erosion, preventing the growth of noxious weeds, and maintaining the scenic quality of an area. This process includes interim reclamation of roads, including reclaiming a road to become primitive while allowing access to a location.

### 3.6.1. Topsoil Conservation

Topsoil is removed from the entire cut and fill area for the pad, and temporarily stockpiled on location for reuse during interim and final reclamation. The stockpile is completed in a manner to reduce erosion potential from wind and water. The depth of topsoil to be removed is determined during the onsite inspection and specified in a pre-drill document such as the Surface Use Plan of Operations or the Application for Permit to Drill. Subsurface materials are never placed on the topsoil conservation location.

### 3.6.2. Revegetation

Revegetation is completed during interim and final reclamation. Interim reclamation allows native vegetation to return to areas where disturbance is no longer needed. Final reclamation is when the entire site is reclaimed. Revegetating a site requires proper topsoil management and invasive weed control to ensure that native vegetation has an opportunity to reestablish itself. Revegetation can be deemed successful when, "a self-sustaining, vigorous, diverse, native plant community is established on the site, with a density sufficient to control erosion and non-native plant invasion and to reestablish wildlife habitat or forage production."[33]

# 4. Drilling

## 4.1. Overview

Drilling is conducted to reach oil and gas reservoirs to allow a pathway for extraction of these fossil fuels. Drilling a well is a highly coordinated event, usually done by appropriately trained third party drilling contractors. The process is costly and therefore optimization of time is essential, typically involving 24 hour operation of the drilling rig. Continual drilling can also provide greater integrity in the wellbore, reducing the risk of problems that may occur while drilling as well as limit the amount of time that the noise and visual impacts of drilling may affect an area. Upon completion of the drilling process, the rig is moved to the next well location; either on the same pad or at a new location based upon the predefined plan.

The time needed for drilling an oil or gas well is highly variable, based on the geology of an area, rig capabilities, depth and size of the hole, supply management, down hole information, logging procedures, weather, seasonal changes, and any issues encountered while drilling. As more wells are drilled in an area, the drilling time tends to go down as these factors become better understood and the system is well established. Drilling a single well may take a month or two, or be as short as a week to ten days.

An operator first drills a hole to a specific minimum distance below the deepest registered domestic water well or drinking water aquifer in the area and follows a standard casing and cementing procedure. Protecting the aquifers from contamination is a major concern of the oil and natural gas industry. Casing is the term used for the pipe made of steel or high-tech alloys, which is lowered into the hole and cemented into place. There is surface casing, which is used to protect fresh water aquifers. There is also production casing that keeps the hole open so that oil and natural gas can be brought to the surface.

[33] BLM Gold Book at p. 43, accessed April 2011 at http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf.

The Figure 2 and the following dimensions and depths are examples for a gas well:[34]

- Surface casing, a half inch thick steel pipe with an outside diameter of 8 5/8 feet, is put into the hole;
- Cement is poured between the hole and the steel casing and with a thickness of approximately 2 inch all the way up to the surface and is allowed to complete dry;
- The 7 7/8 inch production hole is drilled 200 feet below the target formation also known as the completion zone;
- Production casing is put into the hole is a 3/8 inch steel pipe with an outside diameter of 5 ½ inches;
- Cement is again poured between the hole and the steel casing measuring about 1 inch thick all the way to the surface and seals off formations to prevent fluids from migrating and protects the steel casing from the corrosive effects of other formation fluids;
- Casings are checked for integrity before the well construction process continues and intermediate casing may be necessary in deeper natural gas wells since certain formations are encountered that contain abnormal pressures or conditions;
- Production tubing is set in place after the completion process and is quarter inch steel tubing with an outside diameter of 2 7/8 inches running from the bottom of the hole to the surface;
- At the bottom of the hole 40 feet of cement is poured with a plastic plug on top to complete the sealed well bore;
- The production casing is perforated in the completion zone to allow natural gas to flow into the production tubing; and
- Gas wells are separated from the surrounding surface formations by 4.125 inches of steel pipe and cement that make up the casing of a well, which is designed, among other things, to isolate gas wells from any nearby domestic water wells.

[34] La Plata County Energy Council, Gas Facts, Production Overview, accessed April 2011 at http://energycouncil.org/gasfacts/prodover.htm.

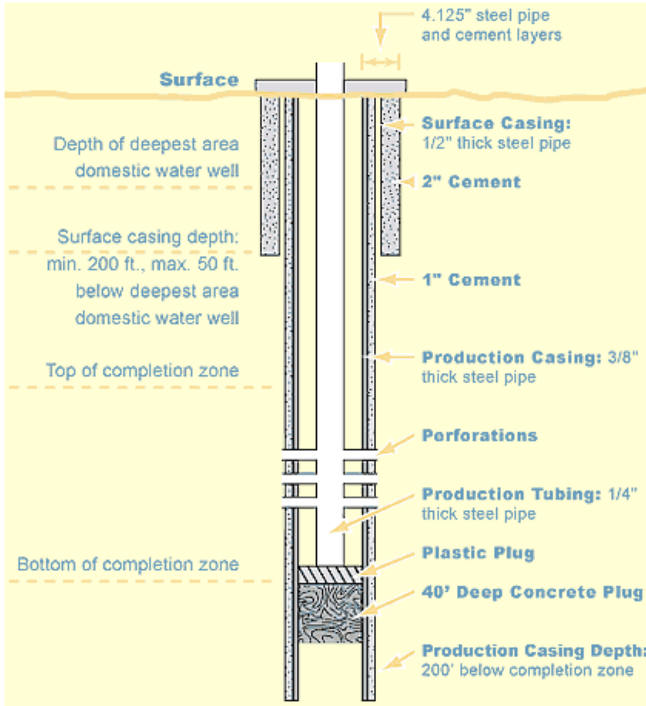


Figure 2. Example of a gas well (diagram is not to scale and has been dramatically shortened).[35]

## 4.2. Drilling Rigs and the Drilling Operations

The drilling rig is the machinery used to drill oil and gas wells. Due to the high degree of variability in locations where drilling occurs and the types of rocks that are drilled, numerous types of drill rigs exist with various components and setups based on the requirements of the area. The basic setup for the drill rig is listed below.

- Drilling derrick is used to position and support the drill string. Modern drilling equipment comes in a wide range of sizes. Many wells can be drilled with equipment that requires far less space than in the past.
- Drill rigs now run on electricity to supply the power to turn the bit and raise and lower the drill pipe and casing. Since most drilling occurs in remote areas, the electricity is supplied by electric power generators that run on diesel fuel. Although the generators are noisy, these generators still make drilling rigs much quieter than in the past.

  In areas where it is possible, including for many of the drilling rigs on the Alaska North Slope, the rigs have been configured to be able to plug into highline power. Modifications have been done to the drilling and production pads to enable the drilling rigs to utilize high voltage AC power directly from the overhead powerline sources. This practice saves operational costs by reducing the burning of expensive ultra low sulfur diesel and greatly reduces emissions from the rigs.

[35] La Plata County Energy Council, Gas Facts, Production Overview, at http://energycouncil.org/gasfacts/prodover.htm.

- The drill bit uses three conical shaped cutting surfaces to grind rock into rice-sized particles. The newest bits drill 150 to 200 percent faster than similar bits just a few years ago. The drill string consists of lengths of pipe fastened to each other and to the drill bit. The drill string transmits power from the top drive to the drill bit.
- As the drill cuts into the rock, drilling mud is added to the hole. This helps cool the drill bit, and the mud is circulated to bring cuttings to the surface. The weight of the drilling mud keeps the hole open. It also helps counteract the pressure of any gas or fluids encountered along the way, in this way preventing a well from loss of control or "blow out."

Protecting the aquifer from contamination is a major goal of the oil and natural gas industry when drilling. Casing made of steel or high-tech alloys is lowered into the hole and cemented into place to protect fresh water aquifers. The casing also keeps the hole open so that oil and natural gas can be brought to the surface.

To reduce waste, the drilling mud is passed through a sieve where the ground rock particles or cuttings can be removed. Then the mud is recycled back into the hole. Dirt and rock cuttings are removed from the hole and temporarily stored nearby. Holding areas are carefully sited, lined and often times covered with nets to protect local wildlife.

All aspects of the drilling operations are closely monitored to ensure efficient drilling and safety. Electronic sensors measure drilling rates, vibration, pressure, rock type, mud properties and many other drilling parameters. Computers monitor operations and collect data from inside the well. With advanced communications technology, drilling personnel can share and review these data with engineers and geologists located thousands of miles away. If a problem is detected, the rig can be safely and quickly shut down.

#### 4.2.1. Types of Drill Rigs

Many types of drilling rigs exist based on the demand of producers and the specific needs of the unique environments and geologic conditions that exist in areas of petroleum accumulations. A few examples of types of rigs are listed below with brief descriptions of each and the operating environment.[36]

**Land Based Drilling Rigs:** The land-based drilling rig is the most common type used for exploration. Conventional, land-based drilling rigs are smaller and more efficient than those used in the past. There are light modular drilling rigs that can be deployed more easily in remote areas than conventional rigs. Fabricated from lighter and stronger materials, these rigs are built in pieces that can be transported individually and assembled on site. The lower weight of components and the rig reduces surface impacts during transport and use. The modular design also allows the rigs to be quickly disassembled and removed when drilling operations are completed.

[36] U.S. Department of Energy, Office of Fossil Energy, (DOE). 1999. "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology" DOE-FE-0385, Washington, DC, at pp 38-39. Accessed April 2011 at
http://fossil.energy.gov/programs/oilgas/publications/environ_benefits/env_benefits.pdf, and
API. "Adventures in Energy: Exploration and Production, Drilling Rigs." Accessed April 2011 at http://www.adventuresinenergy.org/Exploration-and-Production/Drilling-Rigs.html.

**Slim Hole Drilling Rig:** A conventional drill bore might be 18 inches in diameter; a slim hole bore can be as little as 6 inches. A slim hole well drilled to 14,760 feet may produce one-third the amount of rock cuttings generated by a standard well. The size of the drill site can be as much as 75 percent smaller, since slim hole equipment requires less space than conventional equipment. Slim hole drilling is not technically feasible in all environments. One environmental benefit of slim hole drilling is reduction in the quantity of cuttings due to the smaller hole size.

**Coiled Tubing Drill Rig:** Conventional wells are drilled using sections of rigid pipe to form the drill string. When light drilling is required coiled tubing technology can replace the typical drill string with a continuous length of pipe stored on a large spool. This approach has benefits, including reduced drilling waste and minimized equipment footprints, so it is especially useful in environmentally sensitive areas. This technology is best suited to re-entering existing wells and drilling laterally (sidetrack holes) from the existing wells to extend production. Coiled tubing drilling (CTD) continues to be an important rig intervention tool for accessing oil reserves across the North Slope, Alaska. The disadvantages associated with the technology include that it has limited reach and tubing size availability, is prone to fatigue and sticking and it cannot be rotated at the surface.[37]

**Fit for Purpose or Built for Purpose Rigs:** As drilling technology continues to advance, rigs are starting to be designed or retrofitted for specific operations. These rigs streamline the entire drilling process, allowing for environmental consideration and reduce drilling costs and exposure of personnel to potential hazards. In sensitive environments, most fit for purpose rigs have some ability to drill multiple wells from one pad location. The operator often uses skids or feet to move the rig small distances on one pad location versus breaking down the rig to move it to the next well pad.[38, 39]

**Rigs Used in the Arctic:** The original drill rigs used on the North Slope of Alaska were imported from the continental US. Due to highway load and height restrictions, it is necessary to dismantle such rigs when moving well-to-well even if the distance is not far. The original 120-foot well spacing at Prudhoe Bay was necessary so sufficient room was available to lay the derrick down. A new generation of Arctic drill rigs were developed that were enclosed against severe Arctic weather, and could also be quickly disassembled and transported. In some cases, moves that previously required a week could now be accomplished in a matter of a few hours. These relatively compact and modular rig designs also allowed the well-to-well distance to be reduced in some cases down to 10 feet.

### 4.2.2. Advanced Drilling Techniques

[37] API. "Adventures in Energy: Exploration and Production, Drilling Rigs." Accessed April 2011 at http://www.adventuresinenergy.org/Exploration-and-Production/Drilling-Rigs.html, and "Coiled tubing technical advances cut operational costs sharply." *Drilling Contractor*, July/August 2005, pp 36-41. Accessed April 2011 at http://iadc.org/dcpi/dc-julaug05/July05-coiled.pdf.

[38] Kolstad, E.S., L.D. Steinke, and L.S. Brady, 2007, "Application of Purpose Built Rig Technology Results in Step Change of Drilling Time, Cost, and Opportunities." 2007 SPE/IADC Drilling Conference. SPE Paper Number 105644-MS, p. 7. doi:10.2118/105644-MS.

[39] World Oil Online. 2008. "Fit-for-purpose, pad drilling rig design." Accessed April 2011 at http://www.worldoil.com/December-2008-Fit-for-purpose-pad-drilling-rig-design.html.

Oil and natural gas wells have traditionally been drilled vertically, at depths ranging from a few thousand feet to as deep as five miles. Today, advances in drilling technology such as specialized high-load drilling rigs, downhole "smart" steering systems and light-weight, high-strength drill pipe are all making possible developments in the distance drilled laterally from the surface location. This allows oil and natural gas companies to reach more reserves while reducing environmental impact by:

- Reducing the surface "footprint" of drilling operations;
- Drilling smaller holes and generating less waste;
- Creating less noise;
- Avoiding sensitive ecosystems by horizontal drilling; and
- Completing operations more quickly.

Some technologies used today include:[40] [41]

**Horizontal Drilling:** Horizontal drilling is a form of directional drilling that starts with a vertical wellbore that turns horizontal as the well approaches the "pay" or hydrocarbon reservoir. This technology is ideal for thin, but laterally continuous hydrocarbon accumulations, such as shale gas and oil. This lateral wellbore optimizes contact with the oil and or gas bearing rock, reducing the number of wells needed to access the same footages of pay. This technique may also be used to access reservoirs while avoiding sensitive surface conditions.[42]

**Multilateral Drilling:** Sometimes oil and natural gas accumulations occur in discrete layers within the rocks of the crust that are vertically stacked and separated by non hydrocarbon bearing units. Multilateral drilling allows producers to branch out from the main well to tap reserves at different depths dramatically increasing production from a single well and reducing the number of wells drilled on the surface. First introduced in 1993, multilateral drilling is often brought into a field later in the development stage, but has yet to be used from inception of the field to test the true potential environmental benefit of reduced footprint.[43]

**Extended Reach Drilling:** Extended reach drilling is a combination of directional and horizontal drilling techniques that allows producers to reach deposits that are greater distances away from the drilling rig. This can help producers tap oil and natural gas deposits under surface areas where a vertical well cannot be drilled, such as under

[40] DOE, 1999, "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology" pp. 34-41. Accessed April 2011 at http://fossil.energy.gov/programs/oilgas/publications/environ_benefits/6drill.pdf.
[41] API. Natural Gas, Advanced Drilling Techniques. Accessed April 2011 at http://www.api.org/aboutoilgas/natgas/drilling_techniques.cfm.
[42] API. Environment, Health, Safety, Water, New Directions in Drilling. Accessed April 2011 at www.api.org/ehs/water/directional-drill.cfm.
[43] Oberkircher, J., R. Smith, and I. Thackway, 2003, "Boon or Bane? A survey of the First 10 Years of Modern Multilateral Wells." 2003 SPE Annual Technical Conference and Exhibition. SPE Paper No. 84025, p. 11. doi:10.2118/84025-MS.

developed or environmentally sensitive areas. These wells have now reached laterally over five miles from the surface location.[44]

**Complex Path Drilling:** Complex well paths can have multiple twists and turns to try to hit multiple accumulations from a single well location. Using this technology can be more cost effective and produce less waste and surface impacts than drilling multiple wells.

### 4.2.3. Hoisting and Rotating Systems

The hoisting system lifts drill pipe in and out of the well and controls weight on the drill bit as it penetrates the rock. The system also handles the drill pipe out of the wellbore and is used to run casing into the wellbore.

The rotating system turns the drill bit so that it can penetrate underground rock and sand formations. Previously a Kelly or rotary table located on the rig floor provided the rotary motion for the drill string, a process requiring significant manual labor that placed people working on the rigs in a potentially hazardous environment. The current technology for both hoisting and rotating is a top drive system, which consists of one or more hydraulic motors that are suspended from the derrick and attached to the drill string by a short pipe called the quill. The setup allows for easier vertical mobility, the ability to drill with three joint stands at a time, and faster connections or removal of the drill pipe.[45, 46]

The top drive system can be used in nearly all environments from truck mounted rigs to offshore operations, with some modifications based on the specific environment.

### 4.2.4. Circulating System and Drilling Fluids

The circulating system is key to the success of a drilling operation. The drilling fluid or drilling mud is: formulated and maintained; circulated downhole to cool the drill bit and flush drilled cuttings from the bottom of the wellbore; used to transport cuttings to the surface where it is mechanically removed from the mud system; and returned to the tanks where the process starts again.

Under certain conditions, wells can be drilled using air, mist, or foam as the drilling fluids.[47] Air percussion or pneumatic drilling is used for natural gas wells in regions such as Appalachia can eliminate the need for drilling liquids during drilling operations. As a result, only drill cuttings are generated, significantly reducing requirements for waste management and disposal. Although this technology has limited application, it can be an

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[44] See, e.g., State of Alaska, Beaufort Sea Areawide Oil and Gas Lease Sale, Final Finding of the Director, November 9, 2009, Appendix C: Directional and Extended-Reach Drilling. Accessed April 2011 at http://www.dog.dnr.state.ak.us/oil/products/publications/beaufortsea/bsaw2009_final_finding/BS%20Final%20BIF%20AppC-DirDrill.pdf.
[45] Rigzone. Training, How it Works, *How Does a Top Drive Work?* Accessed April 2011 at http://www.rigzone.com/training/insight.asp?insight_id=332&c_id=24.
[46] See, e.g., Drillmec Drilling Technologies, Accessed April 2011 at http://hhseries.drillmec.com/_vti_g1_1.aspx?rpstry=1_ .
[47] William C. Lyons, Ph.D., P.E., Boyun Guo, Ph.D., Reuben L. Graham, B.S., and Greg D. Hawley, B.A., *Air and Gas Drilling Manual (Third Edition), Applications for Oil and Gas Recovery Wells and Geothermal Fluids Recovery Wells* (Gulf Professional Publishing, 2009).

effective underbalanced drilling tool in mature fields, in formations with low downhole pressures, and in fluid-sensitive formations.[48]

Drilling mud is primarily water-based clays and inert weighting materials. It is formulated using various additives, depending on expected well conditions. The drilling fluid facilitates the drilling process by suspending cuttings, controlling pressure, stabilizing exposed rock along the wellbore, providing buoyancy, and cooling and lubricating of the drill bit.[49]

The composition of the drilling fluids is determined by the potential downhole environment to be reached while drilling. In certain geographic regions, specific drilling fluids (oil or saltwater) are used when drilling deep, high-temperature, high-pressure, water-sensitive reservoirs, or high-angle wells. For example, interaction between water in the drilling fluid and the clay-like materials found in shale can cause wellbore instability, calling for "shale inhibitors" in water based drilling fluid. Synthetic drilling fluids combine the higher drilling performance of oil-based fluids with the lower toxicity and environmental impacts of water-based fluids. Because synthetic-based fluids can be recycled, they generate less waste than water-based fluids. Compared to oil-based fluids, synthetic fluids have low-toxicity and low-irritant properties that significantly enhance worker health and safety.[50]

After the drilling fluid has been formulated, it is stored in tanks before it is pumped down the drill string. As the fluid exits the drill bit nozzle, it cools the bit and flushes away any drilled cuttings and solids at the wellbore bottom. The fluid then carries the drilled solids to the surface where it is removed using cleaners (i.e., hydrocyclones or desilters, centrifuges, and shale shakers). When drilling stops, the fluid suspends the cuttings in the well, preventing the hole from becoming clogged.

#### 4.2.5. Casing and Cement

Casing a well or setting pipe consists of running steel pipe inside the newly drilled wellbore, with the space between the pipe and formation to be filled by cement based on the regulations of the state. The casing is assembled of joints of pipe, usually 40 feet in length held together by couplings.[51]

There are four main types of casing: conductor, surface, intermediate, and production (see Figure 3). Conductor pipe is very shallow, usually less than 100 feet and prevents the circulation of drilling fluids outside the casing that can cause erosion. Surface casing, which can be run several thousand feet deep, acts a protection for the freshwater zones that may be encountered while drilling and a support for the blow out preventer and deeper casing. Surface casing depths are regulated by the state based on the depth of

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[48] DOE, 1999, "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology" p 40, accessed April 2011 at http://fossil.energy.gov/programs/oilgas/publications/environ_benefits/6drill.pdf.

[49] Rigzone. Training, How it Works, *How Do Drilling Fluids Work?* Accessed April 2011 at http://www.rigzone.com/training/insight.asp?insight_id=291&c_id=24.

[50] DOE, 1999, "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology" p 40, accessed April 2011 at http://fossil.energy.gov/programs/oilgas/publications/environ_benefits/6drill.pdf.

[51] API. "Adventures in Energy: Exploration and Production, Completion." Accessed April 2011 at http://www.adventuresinenergy.org/Exploration-and-Production/Completion.html.

potential freshwater zones and predicted total depth of the well. Intermediate casing is used to isolate formations that may cause a problem in the well, such as when drilling from high pressure or strength into low pressure or strength, or the opposite scenarios. Production casing, which is the last type of casing run into the well, connects directly to the producing reservoir. In certain situations where the well total depth would require very costly amount of production casing or to isolate a potential problem zone, a lower diameter liner string may be used, which is attached via liner hangers in the casing string and cemented into place.

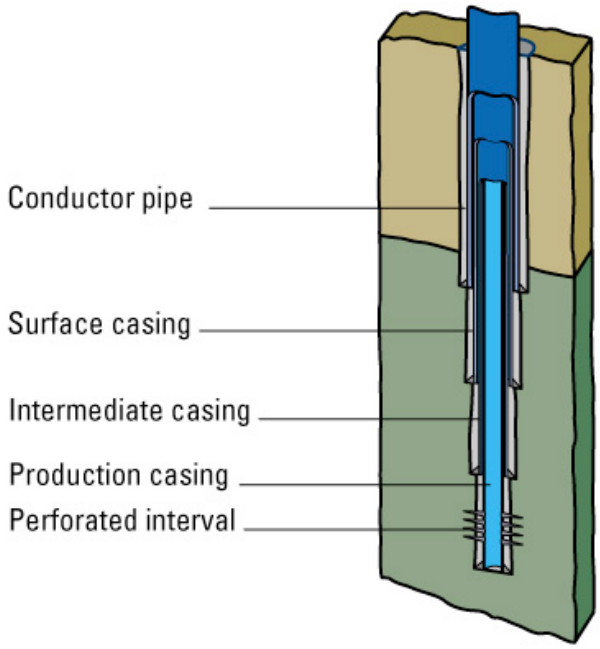


Figure 3. Types of casing.
http://www.glossary.oilfield.slb.com/Display.cfm?Term=casing (Schlumberger. All rights reserved.)

Cement permanently seals the annular space between the casing and formation and serves the following functions:

- Supporting loads applied to the casing;
- Isolating non producing formation from producing formation;
- Protecting casing from corrosion; and
- Confining high or low formation pressures.

The cement used is called Portland cement and is enhanced with additives to fit one of eight API standards based on the specific needs of the wellbore. The cement bond between the casing and formation is tested by a logging run called the cement bond log. This sonic tool evaluates the amplitude of an acoustic signal, looking for attenuation caused by a solid bond between the cement and casing wall.[52]

[52] Lyons, William C. and Plisga, Gary, J., eds., *Standard Handbook of Petroleum and Natural Gas Engineering (Second Edition)*. (Elsevier Inc., Gulf Professional Publishing: 2004).

Cold surface temperatures necessitated development of special well cements for Arctic operations. Desired cement properties included relatively low slurry density, higher yields, accelerated set time at low temperatures, and low heat of hydration to avoid permafrost melting.

### 4.3. Cuttings Management and Disposal[53]

Cuttings must first be separated from the drilling fluid system accomplished by circulating the fluid and cuttings over vibrating screens, called shale shakers. The liquid passes through the screen and is recirculated into the drilling fluid system. The solids are moved from the screens into a storage device such as a pit or tank. The drilling fluid that is recirculated through the system often times is further treated for solids removal using hydrocyclone-type desanders and desilters, mud cleaners, or rotary bowl decanting centrifuges. These technologies separate the finer solids from the system, adding them to the larger screened cuttings.

The management and disposal of cuttings after separation varies by the drilling fluid additives used and constituents of the cuttings. The following list summarizes several disposal, treatment or use options based on specific characteristics of the cuttings and the end-use planned for the specific location.

**Cuttings Treatment:** The cuttings can be solidified or stabilized using additives such as high pH fly ash, cement, and lime, or mica-based material, cellulose fibers, walnut nut plugs, and other natural materials if determined to be potentially hazardous (i.e., heavy metals). The solidified and stabilized cuttings can be used for road foundations, backfill for earthwork, and building material as described in the reuse section. This process is limited by the break down potential of the cuttings if the established equilibrium is upset by outside forces, potentially causing leaching. Volumetrically, this process increases the solids for disposal. Additional treatments of the cuttings include thermal removal of the hydrocarbons or simply further screening and filtering.

**Reuse:** The cuttings with acceptable hydrocarbon content, moisture content, salinity, and clay content can be reused in a number of situations, including:

- Road spreading to replace the tar and chip surfacing process, using oily cuttings. This is heavily regulated and needs prior agency approval. The technique is limited to areas not in close proximity to water ways and in a method that prevents free oil on the surface.
- A North Slope company demonstrated that appropriately processed drill cuttings could be ground and used in road construction since the material was essentially identical to native gravel and surface soils.
- Cuttings can be reused as construction material in the form of fill material, daily cover material at landfills, and aggregate or filler in concrete, bricks or block manufacturing.

[53] Information for section sourced from DOE, Argonne National Laboratory Environmental Science Division, Drilling Waste Management Information System - Drilling Waste Management Technology Descriptions, Accessed April 2011 at http://web.ead.anl.gov/dwm/techdesc/index.cfm.

- Potential future uses include restoration of wetlands, which has only been successfully applied in labs and cuttings for use as fuel.

**Bioremediation:** Bioremediation involves the use of microorganisms to naturally degrade hydrocarbons and other components of cuttings and is accomplished in land based applications and more controlled programs.

- Applying cuttings to the land is a form of bioremediation and can be considered as both treatment and disposal. Land farming is the repeated application of oily waste applied to a specific parcel of land in a controlled manner. The naturally occurring microorganisms in the soil biodegrade the hydrocarbons and dilute any metals in the cuttings. This process can benefit the soil by increasing the water retaining capacity. Land farming requires proper management and testing to be sure that the soil is not damaged and contaminated fluids do not leave the site. Land treatment is the one time application of drill cuttings to a field with the same principles as seen in the land farming. The technique is less expensive than many other disposal options, but is slow and needs careful monitoring.
- Composting involves mixing the cuttings with wood chips or straw to increase the porosity and therefore aeration potential. The mixture is typically held at a specific controlled location, which reduces potential for contamination from runoff. This process is expensive and needs specific controls such as water, temperature, and composition, but is effective and more efficient than land based applications. Bioreactors are a more controlled version of bioremediation where the cuttings are mixed with water and other nutrients on a semi-continuous basis. This process is more expensive than composting, but highly effective.

**Slurry Grind and Inject:** Slurry injection technology involves grinding or processing solids into small particles, mixing it with water or other liquid to form a slurry, and injecting the slurry into an underground formation at pressures high enough to fracture the rock.

- Two common forms of slurry injection are annular injection and injection into a disposal well. Annular injection introduces the waste slurry through the space between two casing strings (known as the annulus). The slurry enters the formation at the lower end of the outermost casing string. The disposal well alternative involves injection to either a section of the drilled hole that is below all casing strings, to a section of the casing that has been perforated with a series of holes at the depth of an injection formation, or transportation and injection at another location. The underground injection and disposal of liquid waste is regulated under EPA Underground Injection Control (UIC) regulations.[54]
- Slurrification of waste drill cuttings and underground injection on a very large scale was developed in Alaska. Historically, the drilled earth or cuttings and waste drilling fluid were disposed of in pits excavated adjacent to the well location. On the North Slope, gravel berms were placed to enclose an area along the drill pad to confine the cuttings and waste drilling fluids. These gravel berms would become porous during

[54] DOE, Drilling Waste Management Information System, Fact Sheet, Slurry Injection of Drilling Wastes. Accessed April 2011 at http://web.ead.anl.gov/dwm/techdesc/slurry/index.cfm.

the short Arctic summer and some fluids would escape the confinement. Investigation to determine the best method to remediate the pits and to isolate and confine the cuttings resulted in development of the grind-and-inject technique, which combines use of continuous miners (used in the coal industry), large ball mills (used in the mining industry), and regulated underground disposal of liquid waste (used in several industries). The cuttings are excavated from the pits and transported to the mill, where they are pulverized to resemble sand and slurried with water so that they can be injected into large porous formations from 4000 to 6000 feet underground. By employing this grind-and-inject process, reserve pits have been eliminated on the North Slope and the technique is employed elsewhere in Alaska.

### 4.4. Well Control Procedures and Equipment

The purpose of well control encompasses precautionary measures, including to prevent a kick (sudden increase in formation pressure resulting in formation fluids entering the wellbore) or a blowout (fluid pressure of the formation overpowers the counteractive drilling fluid pressure). Well control procedures and equipment are designed based on the conditions expected to be reached while drilling and completing the well. The primary active well control component therefore is monitoring of drilling fluid pressure in the well bore and monitoring of the drilling fluid system. Some rigs are equipped with a mud float gage that will sound an automatic alarm if the mud exceeds a predetermined level, which is an indication that a kick is occurring.[55]

The passive component of well control is the blowout preventer (BOP). This piece of equipment is bolted in place after the surface casing is set and cemented and it not removed until production equipment is installed. There are four main sections of most common BOPs: the annulars, pipe rams, blind or shear rams, and crossover spools with additional fluid circulating equipment consisting of the kill lines, choke line, and flare line.[56]

The annular, typically placed at the top of the BOP stack is a valve designed to mechanically squeeze inward to seal either the annular space between the drill pipe and the wellbore or the openhole with the advantage of size flexibility.[57] Pipe rams are designed for a specific pipe size, increasing the pressure control rating, but allowing for minimal flexibility. The function of a pipe ram is to close off the space. Blind rams seal off the well by closing and the connection of the sides is the closure mechanism. The shear ram and blind ram combination, which is typically a last resort, cuts the drill pipe, and the blind ram covers the drillstring-free well.[58]

The crossover spools are the metal junctions where the kill lines attach to the choke, allowing for heavier mud to reach the wellbore in case additional mud weight is needed to control pressure. The choke line allows drilling mud to circulate through a choke

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[55] Occupational Safety & Health Administration (OSHA), Oil and Gas Well Drilling and Servicing eTool, Drilling - Well Control. Accessed April 2011 at http://www.osha.gov/SLTC/etools/oilandgas/drilling/wellcontrol.html.
[56] Ibid.
[57] Schlumberger Online Oilfield Glossary, Annular Blowout Preventer, accessed April 2011 at http://www.glossary.oilfield.slb.com/Display.cfm?Term=annular%20blowout%20preventer.
[58] API. RP 53: Recommended practices for blowout prevention equipment systems for drilling wells. Edition: 3 (2004).

manifold, reducing the fluid pressure to atmospheric allowing the mud and gas to be sent to the flare line for disposal or burning preventing a kick from becoming a blowout.[59]

A wellhead or "Christmas Tree" is installed once the well has been drilled. This is a device placed on the well at the surface to regulate the flow from the well into the pipelines that take the oil and natural gas to facilities for processing and sale. It consists of a series of valves that are opened and closed to regulate flow for optimum field production or to shut down a producing well if a problem is detected. Christmas Trees can have computer systems allowing for remote monitoring, opening, and closing.[60]

The downhole safety valve (DHSV) is intended as a last resort method of protecting the surface from the uncontrolled release of hydrocarbons. It is a cylindrical valve with either a ball or flapper closing mechanism. It is installed in the production tubing and is held in the open position by a high-pressure hydraulic line from the surface. The valve operates (close) if the high pressure line is cut or the wellhead or tree is destroyed.

This valve allows fluids to pass up or be pumped down the production tubing. When closed, the DHSV forms a barrier in the direction of hydrocarbon flow, but fluids can still be pumped down for well kill operations. It is placed as far below the surface as is deemed safe from any possible surface disturbance.

The annular safety valve is installed on wells with gas lift capability, which will isolate the annulus for the same reasons a DHSV may be needed to isolate the production tubing in order to prevent the inventory of natural gas downhole from becoming a hazard.

### 4.5. Operating Flare

Residual natural gas may be present in the drilling fluid returning to the surface. The gas needs to be removed because it will change the density of the fluid and may have a safety impact. A vessel or tank is used that allows the gas to separate from the fluid, a "gas buster". The fluid is returned out the bottom to be used again, and the gas is piped out the top, away from the rig to a flare, which is usually located at least 150 feet from the rig. This flare is located in a pit ranging in depth from five to six feet and width at approximately ten feet. There is a spark plug igniter on the flare that ignites any gas sent from the gas buster. These operating flares are not frequently used and are only required when gas is present in the drilling fluid in quantities necessitating separation and disposal.

### 4.6. Produced Water from Drilling

Produced water is a term used to describe water that is produced or flows out of the well along with the oil and gas. Oil and gas reservoirs can have water naturally occurring in the reservoir rock with the hydrocarbons. This formation water can have varying composition in salinity, total dissolved solids, temperature, and other water quality parameters based upon the characteristics imparted to the water by the rock where the water has resided for potentially millions of year. The water quality parameters can vary between basins and formations, resulting in variations for water management plans.

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[59] OSHA, Oil and Gas Well Drilling and Servicing eTool, Drilling-Well Control: http://www.osha.gov/SLTC/etools/oilandgas/drilling/wellcontrol.html.
[60] API. "Adventures in Energy: Exploration and Production, Completion." Accessed April 2011 at http://www.adventuresinenergy.org/Exploration-and-Production/Completion.html.

The operator first drills a hole to a specific minimum distance below the deepest registered domestic water well or drinking water aquifer in the area and follows a standard casing and cementing procedure. Protecting the aquifers from contamination is a major concern of the oil and natural gas industry. (Casing is the term used for the pipe made of steel or high-tech alloys which is lowered into the hole and cemented into place. The term surface casing is used for this casing near the surface to protect fresh water aquifers.)

During the entire drilling phase, the water in the ground and the water in the oil and gas reservoir may start to flow into the wellbore where it is not yet separated by the casing and cement. It will be returned to the surface, stored, and treated for reuse, discharge or disposal. The management of produced water is further described in the Field Production section, below.

### 4.7. Reserve Pits

Unlined or lined reserve pits store supplies of water, waste drilling fluids, formation cuttings, rigwash, and stormwater runoff from the drilling location. Unlined pits may be used for freshwater drilling fluid or mud systems. Lined pits are normally used for oil or saltwater based mud systems, in areas of shallow groundwater or in areas adjacent to fresh surface waters.

Liners may not be necessary for some oil or saltwater based mud systems, such as where soil and hydrogeological conditions preclude any adverse impact, or soil, waste mud, and cuttings may be managed to ensure protection of soil and groundwater. Conversely, liners may be required in areas that are hydrogeologically or otherwise sensitive. In specific cases, closed-loop drilling fluid systems may be required to protect environmentally sensitive areas and these systems do not require reserve pits.

States typically regulate reserve pits as follows:

- Construction of pits must comply with land use standards;
- Reserve pits usage is restricted to the drilling operations and pits must be closed shortly after cessation of drilling operations (typically within 6 to 12 months);
- Certain reserve pits may remain open for extended periods, because multiple wells may be drilled from a single well pad; and
- Special regulations, including compliance with applicable water quality standards for reserve pit contents, may be required in environmentally sensitive areas.

### 4.8. Well Evaluation

Rock and fluid properties are important characteristics in determining how much oil and natural gas can be recovered from a reservoir; and are therefore evaluated both during drilling and prior to completions. During and after a well has been drilled, various technologies may be used to help determine if there is enough oil and natural gas in the reservoir to make it economically feasible to initiate recovery operations.

#### 4.8.1. Drilling Fluid, Drill Cuttings and Core Samples

As the drilling fluid is returned to the surface, it runs through a shaker or screen to remove the drill cuttings (small pieces of rock broken up by the drill bit) before the fluid is recycled back into the wellbore. The drilling fluid may be analyzed with sensors to see if trace amounts of oil or natural gas are present, an indication of a possible accumulation at depth. From the drill cuttings, fragments of rock are selected for analysis on a predetermined depth interval that best suits the drilling rate and goals of reservoir evaluation. Samples are cleaned and sieved and viewed under a microscope or with digital imaging. The data obtained during this analysis can be used for indications of porosity and other geological characteristics, reservoir characteristics, and wireline log verification. Historically, rock cuttings were the principal source of well information.

A special bit can be used during drilling to cut a cylindrical piece of rock or core that can be brought to the surface for analysis. This core is sent to a laboratory where direct high quality measurement of porosity, permeability, fluid saturation, strength and other physical attributes, as well as stratigraphic evaluation of the interval can be determined. This analysis provides a valuable indicator of reservoir quality including an indication of how well oil or natural gas would flow through the rock.

#### 4.8.2. Logging

Logging refers to the tests performed during drilling, prior to setting casing (open hole logging) or through casing (cased hole logging) to monitor the progress of the well drilling and better observe subsurface formations. While there are many different logging tools and tests, each is used to better illuminate the true composition and characteristics of the different layers of rock. The main purpose of logging is to distinguish between reservoir and non-reservoir rocks by classifying the subsurface rocks penetrated by the wellbore. Open hole logging allows direct measurement from the rock and can evaluate lithology, resistivity, porosity, and borehole measurements.

#### 4.8.3. Well Testing

A well can tested by letting it flow and sampling or metering the produced oil, gas, and water. This process may require tanks or other types of equipment to separate the oil, gas and liquid (the three phases) to allow for separate measurement. Multiphase meters are devices that measure oil, gas, and water flow rates of a well stream with or without partial separation of these components into individual phases. Multiphase metering techniques were developed as an alternative to measurement methods using two and three phase gravity based test separators.[61] Multiphase metering is coming into greater use on the North Slope of Alaska, offshore and other locations, since it may provide economic and environmental benefits. Multiphase metering equipment is more compact than the conventional well test separator equipment. This allows for facilities with smaller footprints to be built which means less tundra and seafloor are impacted by gravel placement and mining operations.

## 5. Completions and Workover

### 5.1. Completions

[61] Alaska Oil & Gas Conservation Commission. "Guidelines For Qualification of Multiphase Metering Systems For Well Testing" November 30, 2004. p. 3. Accessed April 2010 at http://doa.alaska.gov/ogc/MeterGuidelines113004.pdf.

Once drilling operations are finished, wells are "completed" for production if the potential value of the recoverable oil and natural gas is greater than the cost of drilling and producing the hydrocarbons. If not, the well is “plugged and abandoned” in accordance with industry standards and federal or state requirements (depending on the location) and the site is restored.

Completion is the process of making a well ready to flow for production (or injection). This principally involves preparing the bottom of the hole to the required specifications, running in the production tubing and the associated down hole tools, as well as perforating the casing and stimulating the formation, as required. There can be open hole and cased hole completions, and sometimes the process of running in and cementing the casing is included. The producing formation may also be acidized or fractured to enhance production or injection capacity.

### 5.1.1. Well Perforating and Stimulating

Once the well has been drilled and casing set, it is necessary in many systems to make a connection between the wellbore and the formation through the casing. This is done by running perforation guns, which use small charges to perforate a small hole in the casing, providing the first connection between the wellbore and the formation through the casing. Once the perforations are complete, well stimulation may take place to increase the flow into the well and the technique is usually based upon the characteristics of the rock. Stimulation options are listed below.

**Acidizing:** The following are three main types of operations for acidizing:

- Acid fracturing creates a permeable flow path for hydrocarbons by injecting acid at a rate higher than what the matrix can accept, resulting in fractures. This is only used in formations that are acid soluble, mainly carbonates, and does not involve the use of proppant (particles to hold the fractures open). Acid fracturing does not create fractures with long half lengths (radial distance from the wellbore to the tip of the fracture) compared to proppant fracturing.
- Matrix acidizing uses lower pressure acid pumping to penetrate the formation without fracturing. This process is usually done to remove damage from drilling or completion processes near the wellbore and mainly in sandstone formations (carbonates are less susceptible to damage). This process helps restore the natural permeability near the wellbore. Hydrofluoric and hydrochloric are the main acids used and the process may require additional solvents and spacer fluids to clean out products of reaction and prevent emulsification.
- Acid washing is a technique to remove scaling and precipitates that form from mineral laden produced water within the wellbore by moving acid along the affected surface.

**Fracturing:** This means creating and extending a fracture from the perforation tunnels deeper into the formation increasing the surface area for formation fluids to flow into the well as well as extending past any possible damage near the wellbore. This may be done by injecting fluids at high pressure (hydraulic fracturing), injecting fluids laced with round granular material (proppant fracturing), or using explosives to generate a high pressure and high speed gas flow (TNT or PETN up to 1,900,000 Psi) and (propellant stimulation up to 4,000 Psi). Fracturing is covered in further detail in the next section.

**Acidizing and Fracturing (combined method):** This involves use of explosives and injection of chemicals to increase acid-rock contact.

**Nitrogen Circulation or Nitrogen Lift:** Productivity may be hampered due to the residue of completion fluids or heavy brines, in the wellbore, particularly in natural gas wells. Coiled tubing may be used to pump nitrogen at high pressure into the bottom of the borehole to circulate out the liquids.

Three-phase (oil, other liquids, and gas) portable fluid separators designed for arctic conditions may be installed at a well after a stimulation treatment. This equipment is used to separate, measure and recover produced gas and oil while managing used stimulation fluids and solids returned to the surface. The recovered fluids and solids are removed and injected at a permitted underground injection site. This process essentially eliminates flaring or venting of gas produced during well cleanup and minimizes the volume of oil sent to disposal.

### 5.1.2. Hydraulic Fracturing

Hydraulic fracturing (called “frac jobs” or “frac'ing”) is a process that results in the use of liquids to create fractures in rocks. For oil and gas, the fracturing is done from the wellbore drilled into the reservoir rock formations to enhance oil and natural gas recovery. It stimulates the flow into the wells and has been used for over 60 years in more than one million wells.[62]

Hydraulic fractures may be natural or man-made and are extended by internal fluid pressure which opens the fracture and causes it to grow into the rock. Man-made fluid-driven fractures are formed at depth in a borehole and extend into the targeted rock formation. The fracture width is typically maintained after the injection by introducing a proppant into the injected fluid. Proppant is a material, such as grains of sand, ceramic, or other particulates, which prevents the fractures from closing when the injection is stopped. (Natural hydraulic fractures include volcanic dikes, sills and fracturing by ice as in frost weathering.)

Drilling a borehole or well involves applying downward pressure to a rotating drill bit. This drilling action produces rock chips and fine rock particles that may enter cracks and pore space at the wellbore wall, resulting in damage to the permeability at and near the wellbore. The damage reduces flow into the borehole from the surrounding rock formation, and partially seals off the borehole from the surrounding rock. Stimulating the flow into the well was discussed above, and includes clearing this damage. Hydraulic fracturing can be used to mitigate this damage.

[62] Carl T. Montgomery and Michael B. Smith, "Hydraulic Fracturing—History of an Enduring Technology," *Journal of Petroleum Technology* 62, no. 12 (2010): 26-32. Accessed April 2011 at http://www.spe.org/jpt/print/archives/2010/12/10Hydraulic.pdf; Robin Beckwith, "Hydraulic Fracturing: The Fuss, The Facts, the Future," *Journal of Petroleum Technology* 62, no. 12 (2010): 34-41. Accessed April 2011, at http://www.spe.org/jpt/print/archives/2010/12/Hydraulic2.pdf; and API, Hydraulic Fracturing, accessed April 2011 at www.api.org/policy/exploration/hydraulicfracturing/.

Hydraulic fracture stimulation is commonly applied to wells drilled in tight or low permeability reservoirs. These formations do not have the natural permeability to allow a sufficient amount of flow to the wellbore to produce at economic rates.

Fracturing fluid is the fluid used during a hydraulic fracture treatment of oil, gas or water wells. The fracturing fluid has two major functions: 1) open and extend the fracture; and 2) transport the proppant along the fracture length. Proppant are suspended particles in the fracturing fluid that are used to hold fractures open after a hydraulic fracturing treatment. This produces a conductive pathway that fluids can easily flow along.

The fracture fluid can be any number of fluids, ranging from water to gels, foams, nitrogen, carbon dioxide or air in some cases. Various types of proppant are used, including sand, resin-coated sand, and man-made ceramics depending on the type of permeability or grain strength needed. Radioactive sand is sometimes used so that the fracture trace along the wellbore can be measured. The injected fluid mixture is approximately 99.5 percent water and sand.

The environmental, safety and health concerns regarding hydraulic fracturing are being discussed at the state and national levels in the United States. The use of hydraulic fracturing in conjunction with horizontal drilling has opened up resources in low permeability formations that would not be commercially viable without the technology, including the Marcellus Shale in the Appalachian Basin for natural gas and the Bakken Formation of the Williston Basin in the Dakotas and Montana for oil. Concerns have been raised about the volumes of water required, management of chemicals added to fracturing fluids, management and disposal of fluids after completion of a well, protection of air quality, and protection of underground aquifers used for drinking water.[63] The total quantity of fluid used is not normally an issue in Alaska, since there is ample water supply, portable clean-up separators route the liquids to the producing facilities, and there are no underground sources of fresh water in operating areas of the North Slope of Alaska.

### 5.1.3. Chemical Management

Chemicals are used in the process of completing, acidizing, or hydraulically fracturing a well. Chemical management on site must occur consistent with environmental requirements, including US Department of Transportation (DOT), spill prevention, control and countermeasure, and stormwater protection.

### 5.1.4. Water Management for Completions and Workovers

During completion, stimulation, fracturing and workover activities, water naturally occurring in the reservoir and water used in the operations will be produced. The recovery volume of injected fluids varies greatly through North American oil and gas production; ranging from only a few percent to 100 percent of the volume injected into

[63] U.S. Energy Information Agency (EIA), Assumptions to the Annual Energy Outlook 2010, Report #:DOE/EIA-0554(2010), Release date: April 9, 2010, Oil and Gas Supply Module. Accessed April 2011 at http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas.html.

the wellbore. This recovery is controlled largely by the characteristics of the rock in which the hydraulic fracturing is taking place.[64]

Typically, the fluids used in hydraulic fracturing are stored onsite or nearby prior to and after the fracturing operation. This practice requires transport of the water to and from the location either by pipeline in developed areas or by truck. On location, the hydraulic fracturing fluids from the fresh water used in the fracturing job and the water returned from the well are stored in lined pits, tanks, or other surface impoundments.

As with water produced during drilling and field production, there are a number of management options for this water. This topic is explored further in the field production section below. Three water management options are:[64]

- Injection: The injection of water is regulated under the EPA UIC program and sometimes state programs. The process is regarded as environmentally sound when appropriate injection zones are available.
- Treatment: Municipal or commercial water treatment facilities are available in some areas, typically outside of the urban realm. Considerations for this method are transportation to the facility and obtaining the appropriate permits for the disposal.
- Recycling and Reuse: These options vary by region, but typically involve some type of treatment prior to utilization of the water. Using the water for fracturing is a reuse option, keeping the water in the system.

### 5.2. Workovers and Well Maintenance

The term workover is used to refer to work on an existing well, usually for maintenance or to enhance or restore production. Workover operations include installing tubing and downhole equipment, acidizing or fracturing stimulations, replacing tubing or pumping equipment, recompleting new reservoirs, or plugging and abandoning wellbores. A workover pit is used to contain workover fluids if needed. Workovers rank among the most complex, difficult and expensive types of well work there is.

The production tubing may have become damaged due to operational factors such as corrosion to the extent that well integrity is threatened. Downhole components such as tubing, retrievable downhole safety valves, or electrical submersible pumps may have malfunctioned, needing replacement.

In other circumstances, the reason for a workover may be that changing reservoir conditions make the existing well conditions unsuitable. For example, a high productivity well may have been completed with 5½ inch tubing to allow high flow rates (narrower tubing would have unnecessarily choked the flow). As the well continues to produce, declining productivity may indicate the reservoir can no longer support stable flow through this wide bore. This may lead to a workover to replace the 5½ inch tubing with 4½ inch tubing. The narrower bore makes for a more stable flow.

[64] API. Guidance Document HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010. This document may be viewed by following the links at http://publications.api.org, but is not available for download or printing.

There are workover rigs that are typically used for completion activities and workovers. Drill rigs can also be used, but it is not normal practice, due the higher operating cost of a drill rig as compared to a workover rig.

### 5.3. Coiled Tubing

In workover operations, coiled tubing acts as a beneficial well intervention technology because it allows tasks to be completed without killing the well (stopping the flow). Continuous circulation of fluid is possible regardless of location and direction of travel. Some of the uses include: sands and solids washing, paraffin and asphaltene cleanouts, unloading wells and initiating production, formation stimulation, cementing, sand consolidation, circulating kill weight fluids, logging and perforating tools, fishing (removing items that are down the well), and for production tubing.[37]

### 5.4. Recompletion

Recompletion is a way of reusing an existing well to gather more oil or gas from either the same formation or different formations. Recompletion means changing or adding completion zones (target formations) through one of the following ways: 1) recompletion to the same zone but to the side of the original hole; 2) recompletion to a different zone such as drilling deeper or plugging back to access shallower sections; or 3) recompletion to multiple zones from one well. If the current perforation zone needs to be plugged, a "squeeze job" can be done where cement is pumped into the perforation to be sealed. Recompletions are usually regulated and permitted as new well permits. Recompletions require rig activity that lasts for several days.

### 5.5. Temporary Shut-in

Sometimes the price of oil or natural gas is so low that the cost to produce and process it is higher than the production revenue and creates an economic situation where a well is temporarily shut. The well may later be put back into production. This temporary shut-in is regulated by the state for safety and reporting purposes.

## 6. Field Production

After a well is drilled and completed, the final work is done at the site for producing from the well. At the well itself, this includes installing a wellhead, or the pieces of equipment mounted at the opening of the well to manage the extraction of hydrocarbons from the underground formation. To collect oil or natural gas from the well and begin to treat it for transportation and sale, field facilities, such as flowlines, the gathering system and treatment equipment, are needed.

The wells will often produce a complex mixture of oil, liquid hydrocarbons (such as natural gas liquids), gas, water, and solids, varying from location to location. The treating processes separate the different constituents of the mixture, removing those that are non-saleable, and selling the liquid hydrocarbons and gas. Purchasers have contract standards for the oil and gas accepted, often called pipeline quality. For example, oil purchasers typically limit the amount of basic sediment and water (BS&W) to less than one percent. Gas purchasers set limits on water, water vapor, hydrogen sulfide, carbon dioxide, and BTU content. The following sections describe the various aspects of field treatment used to make the oil and gas reach pipeline quality prior to being sent to gas plants and oil refineries for complete processing. The treatment may begin at the well sites or at more centralized field facilities as part of the gathering system.

The production techniques will vary depending on the type of reservoir and how long it has been in production. For example, whether the well is free-flowing from the reservoir pressure and the amount of water used and produced with the oil and gas may vary over the time the well is producing. The focus here is on what are considered conventional oil and gas production.

## 6.1. Producing the Oil and Gas

### 6.1.1. Oil Production

Conventional or standard oil well extraction in North America has three phases of production: primary, secondary, and enhanced oil recovery (EOR). These techniques are not always sequentially used.

**Primary Recovery:** In typical initial production or primary recovery, the natural pressure of the reservoir is adequate to produce or remove approximately 10 percent of the original oil in place. Sometimes an operator will assisted the natural pressure by using artificial or mechanical lift with a pump in the wellbore or on the surface. As the field ages and natural reservoir pressure drops, primary oil recovery ceases.

**Secondary Recovery:** This phase involves injecting water or gas into the reservoir to increase the reservoir pressure and continue to drive the oil to the wellbore, and can increase the life of a field and improve the recovery to 20 to 40 percent of the original oil. The gas used for injection may be the gas produced from the well and the water used for injection may be produced water from that well or at other wells in the area. As with any injection disposal, produced water used for secondary recovery must be treated prior to injection.

In the Arctic, where the source and disposal of water may be more complicated, companies have demonstrated that the used water and fluids that would normally be considered Class II wastes (such as water and fluids used to pressure test piping, storm water and snow melt, fluids used to wash or rinse equipment, etc.) are compatible with producing formations and fluids and can provide a recovery benefit. Companies may request approval to inject these fluids as part of the recovery projects. This reuse reduces the number of times the fluids have to be handled, transferred, and transported and thus reduces the potential for environmental impact that could occur as the result of a spill.

Although the water and gas methods are most common, other methods are also available. The method selected will be dictated by the formation type and method feasibility.

**Improved or Enhanced Oil Recovery (EOR)**: These techniques increase the mobility of the oil and offer the potential ability to produce 30 to 60 percent or more of oil in place in a field. Reducing the viscosity (stickiness or cohesive properties) allows the oil to flow more readily to the wellbore. EOR utilizes three main categories of technology: miscible, chemical, and thermal. The difference between secondary recovery injection and EOR injection is that secondary occurs at ambient temperatures and EOR involves the addition of energy using mass and heat transfer. Commercial success with EOR has been variable due to the high costs associated with each of the three techniques and the unpredictable effectiveness.

Miscible recovery uses natural gas, nitrogen, or carbon dioxide to lower the viscosity of the oil by mixing the oil and introduced gas. Using carbon dioxide, this technique has the potential environmental benefit of carbon sequestration, while furthering the life of an oil field. For example, carbon dioxide produced by human activities, such as industrial sources at which carbon dioxide is a by-product (i.e., fossil fuel power plants), might be used for flooding in reservoirs.[65]

Chemical injection lowers the surface tension of the oil in the reservoir, increasing its ability to flow. This relatively rare technique injects long chained polymers or surfactants as the injection material.

Thermal recovery, most widely used in California, involves the introduction of heat through steam or other methods to decrease the viscosity of the oil. Steam may be generated using conventionally fired heaters known as thermally enhanced oil recovery (TEOR) steam generators. Produced water may be used as the water source to generate the steam in fields that have produced water with low salinity and other qualities making it appropriate. The steam produced is injected into the formations containing heavy crude oil and used to heat the oil for easier recovery. Injected steam also pushes the oil towards producing wells.

TEOR steam generators are fueled by crude oil, fuel oil or natural gas. Steam generators fired by crude or fuel oil may have sulfur dioxide air pollution scrubbers. When burning crude, fly ash impinges on the steam generator convection tubes. To increase thermal efficiency of the generators, fly ash is removed by washing the tubes with water. The effluent is referred to as stack wash water. Other wastes from steam generators can include fuel oil filters, spent water softening resin, refractory waste, and flue duct ash. Water softening resin is typically used when a central water plant is not available.

TEOR cogeneration steam generators can be used in place of TEOR conventional steam generators. A TEOR cogeneration steam generator consists of a turbine and associated heat recovery boilers (steam generators). Cogeneration of electricity and steam can significantly increase the energy efficiency of the process. TEOR steam generators use soft water, which is water with low concentrations of dissolved calcium and magnesium. Soft water is used as steam generator feed water to prevent scaling. The water softening process creates a waste fluid called regeneration brine. Surplus soft water for disposal (soft water blowdown) is generated during startup and shutdown of both conventional and cogeneration steam generators.

Waste fluids typically generated at TEOR facilities consist of water softener generation brine, surplus soft water, excess deionization process, scrubber waste, and stack wash. A typical waste generated at facilities using steam is boiler blowdown water.

**Air Pollution Control Scrubbers:** Air pollution control scrubbers may be required to control sulfur dioxide ($SO_{2)}$ and particulate matter emissions from exhaust gases of oil-fired TEOR steam generators. The process bubbles exhaust gas through a basic aqueous

[65] EIA. Assumptions to the Annual Energy Outlook 2010; Report #:DOE/EIA-0554(2010), Release date: April 9, 2010, Oil and Gas Supply Module. Accessed April 2011 at http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas.html.

solution (NaOH or $Na_2Co_3$), which reduces $SO_2$ to $NaHSO_3$, $Na_2SO_3$, and $Na_2SO_4$. The scrubber liquor waste typically has a neutral pH and low concentration of heavy metals.

**Deionization:** Deionized water and backwash are two other fluids produced from the water purification process associated with TEOR cogeneration plants. The deionization process involves removing additional dissolved minerals present in water. Deionized water is injected into the turbine combustion chamber to reduce nitrogen oxide emissions. Raw water used in the deionization process is either soft water or fresh water. Excess deionization water and backwash from the water purification process may be commingled with excess produced water, regeneration brine, and soft water blowdown prior to disposal.

#### 6.1.2. Gas Production

Natural gas wells may need additional stimulation or treatments to boost gas recovery. For example, compressors may be used to increase gas lift pressure, inject gas back into the reservoir for pressure maintenance, permit vapor recovery, or assist with the gas flow into central facilities. Compressors may be driven by electric motors or internal combustion or turbine engines.

Depending on the location of the well and the geologic conditions that created the gas in the first place, contaminants such as solid particles, crude oil, water, sulfur, and natural gas liquids (including ethane, propane and butane) may be present.[66] The equipment for gas processing works similarly at or near the wellhead (referred to as field processing) or in a more centralized and complex gas processing plant. The sequencing location (in field or at gas processing plant) varies by location.

**Separation of Crude Oil and Gas:** Separation of natural gas from oil often occurs using equipment installed at or near the wellhead. The process and equipment used to separate oil from natural gas varies. Natural gas is dissolved in oil underground primarily due to the formation pressure. Oil and natural gas can separate during the process due to decreased pressure at the surface. A convention separate consists of a simple closed tank that relies on the force of gravity to separate the heavier liquids like oil and the lighter gases, like natural gas. In some instances, more specialized equipment using pressure and temperature may be necessary.[67]

**Separation of Gas from Other Contaminants:** Common technologies for the removal of natural gas liquids and gas contaminants (hydrogen sulfide and carbon dioxide) are used in the field and at gas processing plants, as described in the sections on gathering systems and gas processing plants. Gas can be produced with liquid or free water, typically separated near the wellhead. This is further described in the produced water section below. Gas that contains water vapor is referred to as wet gas. Separation of wet gas is typically done as part of the gathering system or at the gas processing plant. The gas may also contain solid particles (sand or rock), which is typically removed near the well by equipment called a scrubber.

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[66] API. "Adventures in Energy: Natural Gas Processing, Introduction." Accessed April 2011 at www.adventuresinenergy.org/Natural-Gas-Processing/index.html.
[67] Natural Gas Supply Association. "NaturalGas.org: Processing Natural Gas." Accessed April 2011 at www.naturalgas.org/naturalgas/processing_ng.asp.

The drilling and hydraulic fracturing of a shale gas well may use between 2 and 4 million gallons of water per well.[68] In contrast, production of natural gas from coal beds (coal-bed natural gas (CBNG) or coal-bed methane (CBM)) may produce 8000 to 16,000 gallons of water a day during the initial dewatering phase.[69] Other papers provide further description on shale gas, CBNG, and other types of operations.

### 6.2. Surface Equipment

Surface equipment refers to the equipment needed at the wellhead or nearby during production. Equipment may be needed to get and keep the oil and gas flowing and to treat it before movement into the system. These separators, scrubbers, heat exchangers, glycol systems, absorption oil systems, storage tanks, pumps or compressors, and other equipment must be cleaned periodically to remove hydrocarbons, salts, scale, and other solids that have built up and reduce field production efficiency. Wastes from field dehydration, removal of natural gas liquids, and sweetening may include iron sponge, spent glycol, spent amine, spent caustic and filters and filter media, depending upon the type of systems operated. The products resulting from the cleaning will be handled and disposed of as required by applicable regulations.

Several North Slope oil production facilities have internal hydrocarbon collection systems called closed hydrocarbon drains, which are used to recycle fluids with recoverable hydrocarbons that meet specific regulatory and operational criteria. The hydrocarbon fluids (including used oil) are generated from activities such as general equipment maintenance and repairs, spill cleanups and well workovers and maintenance. Hydrocarbon-containing fluids can also be introduced into the production process externally via vacuum trucks or by injecting the fluids into a production pipeline that goes directly to the facility. Within the facility, the hydrocarbon fluids are sent to separation equipment where the hydrocarbons are recovered and ultimately shipped as sales oil.

### 6.3. Oil, Gas, and Produced Water Treatment and Management

Well products are often a complex mixture of oil, liquid hydrocarbons, gas, water, and solids, varying from location to location. Oil purchasers typically limit the amount of basic sediment and water (BS&W) to less than 1 percent. Gas purchasers set limits on water and water vapor.

The liquid, free water is typically separated out at the wellhead or in the field for a number of wells. The percentage of water may vary by location and length of time the well has been producing. The water is separated out prior to the oil and gas being sent into pipelines. The water may be reused, recycled, or treated for proper discharge or disposal.

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[68] Ground Water Protection Council and ALL Consulting. 2009. Modern Shale Gas Development in the United States: A Primer. p. 66. Prepared for the DOE Office of Fossil Energy and National Energy Technology Laboratory (NETL). April 2009. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

[69] U.S. Geological Survey (USGS). Fact Sheet FS-156-00, Water Produced with CoalBed Methane, November 2000. Accessed April 2011 at http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf.

Produced water is a term used to describe water that is produced or flows out of the well along with the oil and gas. Some oil and gas reservoirs naturally have water in the reservoir rock with the hydrocarbons. This formation water can have varying composition in salinity, total dissolved solids, temperature, and other water quality parameters based upon the characteristics imparted to the water by the rock where the water has resided for potentially millions of year. The water quality parameters can vary from basin to basin and even from formation to formation, resulting in variations for water management plans.

### 6.3.1. Water Separation

**Free-Water Knockout (FWKO):** Free-water is water not linked to oil in an emulsion or in the gas as water vapor. An FWKO is the first vessel to receive produced fluids. The FWKO separates free water from other produced fluids and solids. The separated produced water flows into the water treatment system for further treatment, and disposal or reinjection. Periodically, solids and bottom sludges are removed from the FWKO for reclamation, treatment or disposal.

**Separators:** The simplest separators are pits or tanks. Two-phase separators isolate produced liquids from gases as it flows from the well. Three-phase separators have additional float mechanisms and separate free (non-emulsified) water from produced fluids. These separators may also be called skim tanks, gun barrels (slang term for a wash tank or a large three-stage atmospheric separator), and corrugated plate interceptors (CPIs). These separators rely on gravity and residence time to remove residual free oil and solids from produced water. The gas, oil or condensate and water are then further processed prior to sale or disposal. The primary waste generated by the separator consists of produced sand, scale, and bottom sludges ("bottoms" are solids and sludges that sink) recovered during cleanout operations, and will handled for proper disposal.

Hydrocyclones may be used for separation of oil and wastewater. Hydrocyclones are centrifuges that spin the oil and water mixture to separate the materials. Water is forced to the outside of the unit where it is collected and reused, disposed or put through additional treatment[70].

**Heater or Electrostatic Treaters:** Heater treaters and electrostatic treaters separate emulsified oil and water. Heating breaks up the mixture to separate the oil from water. Remaining natural gas, less dense than oil, rises to the top. The gas is removed to be processed or burned and water is removed and stored for further treatment. Emulsions that cannot be treated successfully in a single pass through the treatment system may be placed in a standby oil tank for recycling and further treatment.

Produced water separated in the treaters goes to a disposal or injection system. As is the case with the FWKO and other production vessels, the treaters are occasionally drained to remove solids and bottom sludges. Treaters that use hay or excelsior sections to absorb minute amounts of oil must be cleaned out periodically, and the absorption material must be replaced.

[70] API. "Adventures in Energy: Exploration and Production, Separating Oil, Natural Gas and Water." Accessed April 2011 at www.adventuresinenergy.org/Exploration-and-Production/Separating-Oil-Natural-Gas-and-Water.html.

**Desanders:** Desanders may be utilized to remove the solids or sands carried by produced water. Much of the produced sand is also removed in other treating vessels.

**Natural Gas Field Dehydrators:** Field dehydration units remove water vapor from the natural gas and perform the same function as those units in gas processing plants, described in greater detail below. Wastes generated during the dehydration process consist of glycol-based fluids, glycol filters, condensed water, and spent solids desiccants, depending upon the type of system operated. These fluids and solids may in some circumstances contain trace levels of hydrocarbons and treating chemicals.

### 6.3.2. Water Treatment and Management

The separators described above are primary treatment for separating the water from oil and gas. After separation produced water may require additional treatment prior to before discharge or re-use.

**Treatment:** Various water quality treatment processes are used depending on the reuse, disposal, or discharge options for the water.[71]

- Skim tanks, gun barrels, and corrugated plate interceptors (CPIs) rely on gravity and residence time to remove residual free oil and solids
- Gas flotation units are used to remove small concentrations of insoluble oil and grease from produced water. The units agitate the water by injecting a gas, usually natural gas or air, through the liquid stream. This action flocculates (aggregates) the suspended oil, grease, and dirt with the gas bubbles. The flocculated materials then rise to the surface and are skimmed off. The material may also be recovered as oil and reused in the system.
- One promising new separation technology is the freeze-thaw or evaporation (FTE) process. Wastewater is separated into fresh water, concentrated brine, and solids using a freeze crystallization process in the winter and natural evaporation in the summer. The fresh water can be used for agriculture or livestock and the volume of waste requiring disposal is greatly reduced. This approach is useful in areas with hot summers and cold winters, such as the Rocky Mountains.
- After separation and treatment of produced water, filtering is can be used to further improve water quality before injection or surface discharge. Filter media must be replaced or backwashed on a periodic basis. Replaceable filters include sock, cartridge, or canister units. Permanent filters may use diatomaceous earth or granular media such as sand or coal or nut shells.[72] The backwash may be done with fresh or produced water, which can contain a small amount of surfactant. The solids removed from the filters should be circulated or sent to a solids treatment and disposal system. Backwash liquid should be returned to the production facilities for reprocessing.

[71] Prosep, "Produced Water Treatment: Selecting the Right Equipment for Your Application," *O&G Next Generation, The Magazine*, Issue 4. Accessed April 2011 at www.ngoilgas.com/article/Produced-Water-Treatment-Selecting-the-Right-Equipment-for-Your-Application/.
[72] Ibid.

**Quality and Quantity:** The water quality and quantity influences the final fate of the water in addition to local, state, and federal requirements. There are a number of methods of reuse and disposal to fit various water types or qualities.

- Discharges to Surface Water: Produced water separated from oil and gas may be of a sufficient quality to discharge after additional treatment as described above. In certain instances, the produced water may be put into pits or additional tanks to separate additional solids and oil from the produced water prior to discharge. Bottoms (solids that sink are referred to as "bottoms") or sludges, are recovered from the settling pit or tank and will undergo proper disposal.
- Evaporation Ponds: Produced water can be placed into a pond and allowed to settle and evaporate. These ponds do not work in many locations and are seen as an increasingly unacceptable disposal method from both environmental and social perspectives.
- Recycling and Reuse: On site water management systems can include tanks and ponds and result in the reuse of water in completions operations at the same well or at nearby wells. To achieve maximum oil recovery, additional water is often injected into the reservoirs to help force the oil to the surface. Produced water may be used for this injection. Both the formation water and the injected water are eventually produced along with the oil. As the field becomes depleted of gas or oil, the water content of the oil increases.[73]
- In some areas of the western United States, produced water extracted with natural gas from coal beds may be of a quality suitable for agricultural, livestock, dust suppression, and wildlife use. This water is usually much less saline than produced water from deeper gas-bearing formations.
- Direct Injection: This method requires a federal Underground Injection Control (UIC) permit and may require other approvals.

**Produced Water Storage:** Produced water can be stored in tanks, pits, or ponds, prior to reuse, recycling, treatment or disposal.

- Produced water tanks may be used for storage and additional settling time for sand and solids removal prior to discharge, injection, or other disposal. The tanks must be cleaned occasionally to remove bottoms, including oily sands and solids.
- See section 1.5.5. regarding use of reserve pits.
- Ponds can be used for evaporation or storage and often require permits from local, state or federal agencies.

### 7. Gathering Systems

In order to connect the production from individual wells, a gathering system is put into place. The gathering system consists of interconnected flow lines or pipelines that move

[73] DOE, Argonne National Laboratory. "A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane," January 2004. Accessed April 2011 at http://www.ead.anl.gov/pub/doc/ProducedWatersWP0401.pdf.

produced hydrocarbons to storage tanks, a transfer station, or other centralized location for transportation or further treatment.

The gathering system includes pipelines or flowlines used for transport and accessory equipment used in the field treating process. Oil and gas gathering systems have unique components. But, both systems typically begin with liquid and gas separation followed by solids removal. After the initial separation, oil gathering system components may include emulsion treaters, gathering tanks, and heater treaters.[74] The gas gathering system may contain compressors, dehydrators, and regulators.[75] The following are facilities or treatments involved in the oil and gas production process to move oil and gas from the individual wells and produce the optimal compositions of oil and gas for introduction into the next stage of transportation. Production facilities at well sites and required treatments throughout the process vary based on the individual characteristics at various locations of the production stream.

Flow lines gather produced fluids from wells for transport to field facilities for processing. The construction of the flow lines and pipeline gathering system must be managed in a manner similar in many ways to the well pad construction. For example, the disturbed areas associated with the flow lines and gathering system feeders from the well pads to other facilities may be considered under a common plan of development with respect to stormwater management.

**Chemical Treating:** Treating chemicals such as corrosion inhibitors are sometimes injected into the well or flowline to provide protection. Either batch or continuous treatments may be used. Chemical injection pumps typically dispense chemicals from 55-gallon drums or bulk containers. Leaks from this process may result in chemical-contaminated soils so spills should be minimized with drip pans and managed as required by applicable state and federal regulations.

**Pipeline Pigs:** The flow lines and pipes may need to be cleared of obstructions or materials on the inside of the pipe. A device called a pig, or pipeline inspection and cleaning gauges, can be sent through the pipeline to scrape the inside. The material may be scale, which will be collected and disposed of, or a heavier hydrocarbon requiring treatment.

### 7.1. Crude Oil Gathering

The crude oil gathering system treatment typically consists of additional separation of solids and gases from the crude oil using emulsion treaters, gathering tanks, and heater treaters. Flow lines and the gathering system for crude oil production can become plugged from naturally occurring materials in the crude oil, such as paraffin, asphaltenes and scale. Plugging material that is not dissolved back into the crude oil is recovered at a pig trap at the facility inlet.

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[74] API. "Adventures in Energy: Exploration and Production, Separating Oil, Natural Gas and Water." Accessed April 2011 at www.adventuresinenergy.org/Exploration-and-Production/Separating-Oil-Natural-Gas-and-Water.html.
[75] API. "Adventures in Energy: Natural Gas Processing." Accessed April 2011 at www.adventuresinenergy.org/Natural-Gas-Processing/index.html.

**Paraffin Removal:** Paraffins, which are organic compounds occurring in all crude oil, vary from gas (C1 to C4) and liquid (C5 to C16) to solid (greater than C16) at room temperature. If temperatures in the transportation of heavier crude oil drops below 40 to 60 degrees Fahrenheit, or pressures are greatly reduced, solidification may occur, potentially causing reduction in well capacity or pipelines. Paraffin solvents or dispersants, heating by pumping hot oil through the lines, or mechanical cutting (such as with a pig), can be used to remove it from the tubing and piping. Paraffin solvents, dispersants, and hot treatment fluids are normally handled and treated as part of the crude stream in the field processing facilities. Paraffin cut with downhole tools is generated at the wellhead. Recovered paraffin solids can be heated and returned to the production system or hauled to a storage site for reclaiming or disposal.

**Asphaltenes:** Asphaltenes is a naturally occurring component in some crude oils and describes certain high molecular weight ring hydrocarbons. The term does not define a true group of compounds, but rather anything that is not soluble in straight chain solvents such as pentane or hexane. Therefore, the composition of asphaltenes among crude oils changes with each type of oil. Deposition of asphaltenes in pipelines and in the near wellbore formation is typically induced by a decrease in pressure and can be prevented by asphaltene deposition inhibitors. However, due to the compositional variability of asphaltenes, deposition inhibitors need to be specifically selected to work with specific crude oils.

### 7.2. Natural Gas Gathering

The natural gas gathering system may contain compressors to maintain pressure for the gas to flow, towers to remove natural gas liquids, dehydrators to remove water vapor, and pressure regulators, and other treatment equipment (see Figure 4).

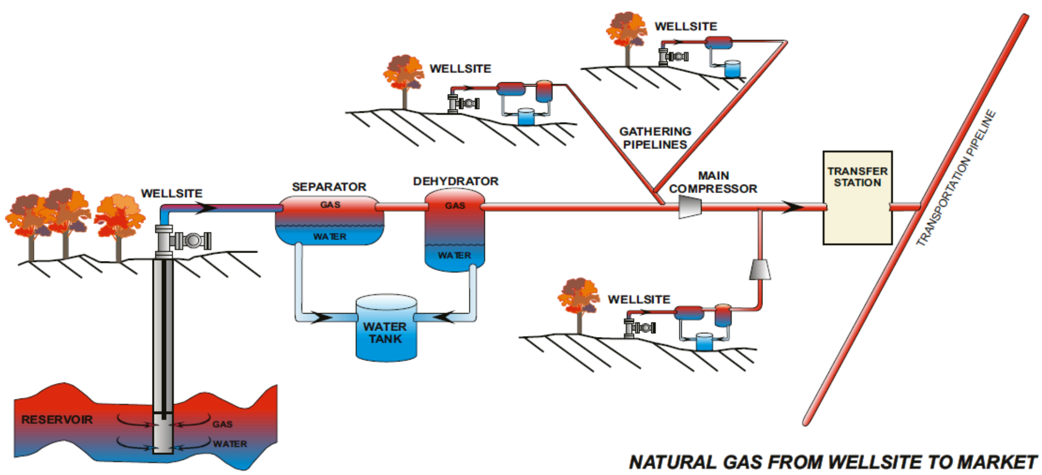


Figure 4: Natural Gas Gathering System.
http://www.talismanusa.com/upload/important_links/5/04/gathering_systems_fact_sheet_oct18.pdf (Permission not obtained yet).

#### 7.2.1. Gas Hydrate Prevention

Pressure and temperature decrease as gas moves from a reservoir thousands of feet below the surface of the earth to the surface. If water or water vapor exists in the gas stream, even in very small amounts, hydrates may form and block flow lines. Hydrates are a solid ice-like material resulting from the combination of a gas with water under pressure. The following natural gas constituents will form hydrates: methane, ethane, propane, isobutane, normal butane, hydrogen sulfide, and carbon dioxide. The greater the pressure in the equipment, the higher the temperature at which the hydrate will form. Hydrates can cause restriction or stoppage of flow, and can be controlled by alcohol injection, heating, or by dehydration of the gas.[76] Methanol is sometimes injected or line heaters, often natural gas powered, are sometimes used to prevent hydrate formation. Methanol is typically used in low concentrations and is dictated by field conditions.

### 7.2.2. Removing the Natural Gas Liquids

Natural gas in residential use for cooking or heating is 90 percent methane, the simplest form of hydrocarbon. Natural gas liquids include ethane, propane and butane or the larger hydrocarbon molecules. These liquids may be removed by lowering the temperature and chilling the liquids in a cryogenic process (described in the gas processing plant section) or using an oil to absorb the heavier liquids.[77] The natural gas liquids will be further processed for sale.

Absorption oil has an affinity for the natural gas liquids, pulling propanes, butanes, pentanes and heavier hydrocarbons out of the mix. This process occurs by sending the natural gas stream through an absorption tower containing absorption oil. The oil catches the heavier hydrocarbons and exits through the bottom of the tower, leaving the more purified light gas stream to exit independently. The now rich oil, containing the natural gas liquids, is heated to the boiling point of the natural gas liquids, which is much lower than the boiling point of the absorption oil, allowing recovery of those natural gas liquid molecules. The process can be modified to remove more of the heavier liquids, such as by cooling the absorption oil before introducing the gas, based on the intended output of the gas stream.[78]

### 7.2.3. Removing Other Gases and Sweetening

Natural gas may be produced with sulfur in the form of hydrogen sulfide gas. It is called sour gas, because the hydrogen sulfide gives it a rotten eggs odor. The process of removing the sulfur is called sweetening and it is discussed in more detail below in the section on gas plant operations.

There are several reasons to remove the sulfur dioxide in the field. In high concentrations, the hydrogen sulfide in the gas may be toxic. It may also be important to remove the sulfur dioxide if the produced gas is to be used for fuel in the field. Finally, the hydrogen sulfide may be corrosive to pipes and needs to be removed before going further in the gathering system and to be saleable.

### 7.2.4. Gas Dehydration

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[76] American Gas Association. "Natural Gas Glossary - Hydrates." Accessed April 2011 at www.aga.org/Kc/glossary/Pages/h.aspx.
[77] Natural Gas Suppliers Association. NaturalGas.org, *Processing Natural Gas, Production.* Accessed April 2011 at http://www.naturalgas.org/naturalgas/processing_ng.asp .
[78] Ibid.

Natural gas typically comes out of the ground with water. As described above, the liquid free water is usually easily separated from the natural gas in the field in a conventional separator. The removal of the water vapor that exists in solution in the natural gas requires a more complex treatment. The water vapor is removed to avoid formation of gas hydrates and to meet quality standards. This treatment consists of "dehydrating" the wet natural gas, which usually involves one of two processes: absorption or adsorption. Absorption is removing the water vapor using a dehydrating agent, such as with the glycol dehydrating systems. Adsorption is condensing the water vapor and collected it on the surface, such as with a desiccant or solid drying agent.[79] These types of systems are described in more detail in the gas processing plant discussion.

## 8. Storage and Sales

### 8.1. Oil Storage and Sales

Regulations governing the accumulation and sales of crude oil are very stringent to protect the interest of the producing party and any other interest holders on the mineral lease. Based on these regulations, accurate measurement of crude oil volumes are absolutely essential.

#### 8.1.1. Storage Tanks

Storage tanks are used for the temporary holding of petroleum products or produced water. Tank use is based on proximity and transportation options from fields to central treatment facilities. The use of onsite storage tanks is controlled by a number of regulations and industry standards relating to design and construction of the tanks, inspection, measurement, emissions, safety and fire protection, leak detection, spill prevention, and other environmental concerns.[80]

The quantity of oil stored in tanks is carefully measured and can be used to double check metering numbers as the liquids move from the lease to the pipeline. Within the tank, any valves below the liquid level often are tagged by seals placed by the crude oil purchaser. If these seals are removed for any reason, including transportation of liquids to sales from the tank, the seals must be presented for accounting purposes.

Typically the sales line openings on storage tanks are located one foot from the base of the tank. The emulsion that forms at the tank bottom, which cannot be sold, remains in the tank below the valve and the discharge of this emulsion is avoided.[81]

#### 8.1.2. Custody Transfer Units

As produced liquids move from the control of one company to another, such as from a lease to a pipeline, a custody transfer unit measures the volumes being transferred. This unit typically operates intermittently based on the presence of liquids in the stock tank,

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[79] Ibid.

[80] *See*, for example, Oil Pollution Prevention regulations, 40 C.F.R. Part 112 (2010), *and* API has numerous Recommended Practices, Standards, Specifications, and Publications for storage tanks available for review at its Government-Cited and Safety Documents website, accessed April 2011 at http://publications.api.org/.

[81] State of Oklahoma, The Oklahoma Commission on Marginally Producing Oil and Gas Wells. *The Lease Pumper's Handbook.* Chapter 10, Section G, p 10G-2. Accessed April 2011 at http://www.ok.gov/marginalwells/Publications/Pumper's_Handbook.html.

selling oil only when approved quantities are available. Another qualifier for the unit is the composition of the oil. If the quality is below pipeline grade, the unit will force oil back to be retreated before it is sent to sales.[82]

### 8.2. Compression and Gas Sales

Natural gas is transported in pipelines, which is discussed in more detail below. The amount of gas that can be transported in a pipeline depends upon how much the gas is compressed. The more the gas is compressed, the greater the volume of gas that can be transported through the pipeline. Uncompressed gas is displaced by compressed gas, essentially stopping the flow of uncompressed gas to the processing plant.

Gas compression can take place right at the well site, as the gas enters the pipeline system, or the gas can be transported by pipeline to a compression facility where it is compressed and then transported to a processing plant. On-site compression is done with small electric or gas-powered compressors. A compression facility contains large electric or gas-powered compressors and is surrounded by a sound absorbing structure. The type of compression used by companies depends upon economic factors and gas well location concerns. If a well is too remote, it is more difficult to tie the well into a compression facility. Some companies try to cluster well sites so that a centrally located compression facility can serve the needs of many wells, thus reducing the noise associated with gas compression.

## 9. Gas Processing Plant Operations

Some processing of natural gas can occur in the field as previously discussed. Additional processing takes place in a gas processing plant. These facilities are typically centrally located in a highly productive area, and gather natural gas from several locations. Although the processes that take place at gas plants are complex and may vary between facilities, the main impurity removal processes are for water removal (dehydration), sulfur removal (sweetening), and separation of natural gas liquids.

The inlet gas streams may vary in composition. The inlet gas may contain compounds such as carbon dioxide, hydrogen sulfide, mercaptans, other sulfur compounds, water, and certain solid impurities. These are removed by gas plant "treating" facilities. In the treated gas, methane is the predominant component, but smaller amounts of natural gas liquids, such as ethane, propane, butane, pentane, and heavier hydrocarbons are also present. The "extraction" facility at the gas plant removes the heavier natural gas liquids (NGLs) for sale. The plant processes the gas into a marketable condition. Gas plant treating and extraction processes may also include inlet compression to a sufficient pressure for operations, and recompression for the treated gas to enter the pipeline for further transportation.

### 9.1. Inlet Separation and Compression

Gas can enter the facility in either an untreated or treated condition. Field production facilities can provide initial treatment and all subsequent treatment is conducted at the gas plant. Produced fluids such as water and liquid hydrocarbons are usually separated at the

[82] Ibid., at p 10G-3.

plant inlet. The incoming gas may need to be compressed to a sufficient pressure to allow the plant to operate.

Inlet separators are designed to send produced water and hydrocarbons to separate process vessels for additional treatment. Produced water can be separated and then treated for disposal or reuse. As liquid hydrocarbons are separated from the gas, they will be recovered for sale.

For safety, inlet separators are equipped with relief valves that vent to emergency containment facilities, including pits. This protects the facility if a fluid slug that exceeds separator capacity should reach the plant or if gas pressure exceeds design capacity.

## 9.2. Dehydration

The liquid free water is usually easily separated from the natural gas in the field in a conventional separator or at the inlet separator at the gas plant. The removal of the water vapor that exists in solution in the natural gas requires a more complex treatment. The water vapor is removed to avoid formation of gas hydrates and to meet pipeline sales quality standards. This treatment consists of "dehydrating" the wet natural gas. This typically involves one of two processes: absorption or adsorption. Absorption is removing the water vapor using a dehydrating agent, such as with the liquid glycol dehydrating systems. Adsorption is condensing and collecting the water vapor, such as with a desiccant or solid drying agent.[83]

### 9.2.1. Glycol Dehydration

Glycol has a natural affinity for water and is used in absorption dehydration or removal of water vapor from the gas stream. Wet gas moves through a pipe into a tank called a "contactor," where the gas is forced to flow down into a pool of glycol solution at the bottom of the tank. The glycol bonds with the water, increasing the mass of the combined molecule, causing the larger and heavier glycol and water molecule to fall to the bottom of the contactor where it is removed. The vapor-free natural gas stream continues out of the top of the contactor and exits the dehydrating unit.

The glycol/water mixture is exposed to heat in a specialized boiler allowing the water to vaporize and the glycol to stay in its liquid state; glycol boils at 400 degrees Fahrenheit. The glycol is recovered for reuse.

In some systems, prior to reaching the boiler, the liquid stream is sent through a flash tank separator. This separator reduces the pressure on the liquids allowing methane and other gases to flash. The methane and other compounds are captured and sent to the gas line instead of being vented to the atmosphere, as is done in the dehydrator systems without flash tank separators.

[83] Natural Gas Suppliers Association. NaturalGas.org, *Processing Natural Gas, Water Removal.* Accessed April 2011 at www.naturalgas.org/naturalgas/processing_ng.asp.

#### 9.2.2. Solid-desiccant Dehydration

This method is typically more effective than glycol dehydration, but requires higher volumes of natural gas moving under high pressure. The wet gas is pumped downward through a tower filled with a solid desiccant (drying agent). The desiccant, which may be alumina, silica-gel, silica-alumina beads, or a molecular sieve, attracts and binds the water molecules so that only dry gas flows out the bottom of the tower. When the desiccant has captured all the water it can, operators flush the tower with heated gas that re-vaporizes the water molecules, thereby reactivating the desiccant.

Wastes generated during the dehydration process consist of glycol-based fluids, glycol filters, condensed water, and spent solids desiccants. These fluids and solids may in some circumstances contain trace levels of hydrocarbons and treating chemicals.

### 9.3. Sweetening and Sulfur Recovery

Natural gas that contains sulfur compounds is called "sour gas" and may have a strong rotten-eggs odor from hydrogen sulfide. The process of removing sulfur from natural gas is called "sweetening." Hydrogen sulfide must be removed because it is toxic when inhaled and the sulfur compounds may be highly corrosive to pipeline walls. If recovered in sufficient quantities, the sulfur compounds can be neutralized to yield pure, marketable sulfur. [84]

The sweetening process may be conducted using units identical in operation to those used at field production facilities. It may also be conducted in dedicated sulfur recovery or carbon dioxide removal facilities where high hydrogen sulfide and carbon dioxide concentrations exist. (Many of the processes that remove the sulfur compounds also remove carbon dioxide from the natural gas.)

Hydrogen sulfide is removed from natural gas by contact with amines (organic chemicals that are analogs of ammonia ($NH_3$)), sulfinol, iron sponge, iron chelate reduction, caustic solutions, and other sulfur-converting chemicals. Heat regenerates amine and sulfinol for reuse. In the iron chelate oxidation-reduction process, oxidation is used to regenerate the solution. Iron sponge, caustic solutions, and other sulfur-converting chemicals are spent in the process and are not regenerated.[85]

**Amine Sweetening:** Amine treating of natural gas for removal of hydrogen sulfide and carbon dioxide is the process that is probably most widely used in the industry. The low density hydrocarbon phase, either liquid or gas, is placed in contact with a heavier, immiscible liquid phase, containing the amine solution, and the carbon dioxide, hydrogen sulfide and carbonyl sulfide from the hydrocarbon phase are transferred to the aqueous phase where they react with the amine. Amines are then regenerated by elevating the temperature to release the hydrogen sulfide and carbon dioxide (acid gases).

**Sulfinol Sweetening:** The sulfinol treating process uses an aqueous mixture of an amine and a physical solvent. This process involves the chemical reaction of an amine with

[84] Natural Gas Suppliers Association. NaturalGas.org, *Processing Natural Gas, Sulfur and Carbon Dioxide Removal*. Accessed April 2011 at www.naturalgas.org/naturalgas/processing_ng.asp.
[85] Kohl, Arthur L. and Richard B. Nielsen, *Gas Purification* (Houston, Texas: Gulf Publishing Company, 1997).

hydrogen sulfide and carbon dioxide, and the physical absorption of these acid gases and other sulfur-containing compounds at feed gas pressure and temperatures.

**Iron Chelate Oxidation-Reduction Sweetening:** When sour gas is contacted with a water solution of chelated iron, the hydrogen sulfide is converted to elemental sulfur in an iron reduction reaction. The solution is regenerated typically by oxidation using air as the oxygen source. This process uses a nontoxic solution and creates little or no hydrogen sulfide or sulfur dioxide emissions. The solid waste generated by this sweetening process is a nontoxic wastewater stream.

**Iron Sponge Sweetening:** Iron sponge is composed of finely divided iron oxide, coated on a carrier such as wood shavings, and the iron oxide reacts with hydrogen sulfide to form iron sulfide. The waste generated in the iron sponge process is the iron sulfide and wood shavings combination.

**Caustic Sweetening:** Small volumes of hydrogen sulfide may be removed from natural gas and natural gas liquids by contact with a caustic solution. Most caustic treaters consist of a simple vessel holding the caustic solution, usually sodium hydroxide, through which gas is allowed to bubble. The solution is reused until spent and the primary waste from caustic treating is spent caustic solution.

**Sulfur-Converting Compounds:** Several different compounds can result in the direct conversion of the hydrogen sulfide using a single contact vessel. Natural gas bubbles through the vessel until the sulfur-converting compound is spent. The products of the reactions vary, so how to use or dispose of the products and spent solutions also varies.

**Claus Process:** An amine or sulfinol solution is used to remove hydrogen sulfide from sour natural gas. As part of the regeneration process, hydrogen sulfide is then burned in the presence of oxygen to produce sulfur dioxide. Hydrogen sulfide and sulfur dioxide are then mixed and exposed to a heated catalyst to form elemental sulfur. The Claus process utilizes pelletized, inert aluminum oxide as a catalyst, as it provides a greater surface area to speed and assist the process.

The primary waste of the Claus process is the spent catalyst.

**Molecular Sieve Sweetening:** High surface area, porous absorbents are used to remove hydrogen sulfide, mercaptans, and heavier sulfide compounds from gases and natural gas liquids. They may also be used to remove water vapor so sweetening and dehydration may be accomplished in the same unit. Molecular sieve sweetening is a batch-type regenerative operation requiring at least two beds for continuous processing. As one bed is sweetening the other is regenerating.

The primary waste generated in molecular sieve sweetening is spent molecular sieve.

### 9.4. Natural Gas Liquids Recovery

The natural gas that comes of out the ground may be composed of hydrocarbons other than methane, which is the simplest form used in most homes for natural gas stoves or furnaces. The heavier components of the natural gas mixture, ethane, propane, butane, pentane, heptane and above, are called natural gas liquids (NGLs). NGLs are separated from the natural gas for other uses.[86] These hydrocarbons are liquids at the surface of the earth and exist as gas at reservoir temperatures and pressures. Each type of heavier hydrocarbon has distinct properties (i.e., boiling point - the temperature at which it goes form a liquid to a vapor) and uses (i.e., propane for grills and butane in lighters).

Facilities exist to recover the heavier hydrocarbons separately from the methane. Natural gas liquids extraction may use compression and cooling, absorption, or cryogenic processes. These processes either: 1) absorb heavier molecular compounds from the process stream with absorption oil that is recycled; or 2) use temperature and pressure to separate fractions with different boiling points.

A significant portion of the NGLs may be removed from the gas stream using an absorption process. The gas mixture passes through an absorption tower with "lean" absorption oil, which catches the non-methane hydrocarbons, allowing the methane to move through. This process is very efficient at removing the propane and heavier portion, but ethane is more challenging to remove and may need additional processing for the gas stream if it remains in high enough concentrations. The absorption oil with the NGLs is heated, releasing the NGLs for further treatment and sale, and the absorption oil can be reused.

The gas can by cryogenically (cold and pressure) treated, which lowers the temperature to the point that methane is the only hydrocarbon that remains in the gas state. The heavier hydrocarbons all become liquid as the temperature drops to about negative 120 degrees Fahrenheit, allowing them to be removed from the methane stream. Further temperature treatments separate each of the heavier hydrocarbons into pure streams using the distinct boiling point of each hydrocarbon.

Wastes generated include lubrication oils, spent or degraded absorption oil, wastewaters, cooling tower water, and boiler blowdown water.

### 9.5. Re-Compression and Plant Utilities

Plant compression and utility systems are necessary to operate the gas plant and to raise the pressure of the plant outlet gas to match the sales gas pipeline pressure. Utilities can include fuel, electrical generators, steam equipment, pumps, and sump systems. Compressors are driven by electric motors, internal combustion, or turbine engines. These engines, compressors, and utility systems generate used lubrication oils, cooling waters, wastewaters, spent solvents such as petroleum naphtha used for cleaning equipment, and oily debris such as rags, sorbents, and filters.

### 9.6. Other Gas Plant Facilities and Operations

Process cleaning wastes identical to those generated at field production facilities are generated at gas plants. Wastes generated during the cleaning process include mixtures of spent cleaning solutions (acids, caustics, solvents, and detergents) and solids or hydrocarbons removed from the system. Other activities that generate waste are warehousing, product storage, maintenance activities, domestic sanitary waste handling and treating, construction and demolition materials, product shipping, laboratory testing,

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[86] Natural Gas Suppliers Association. NaturalGas.org, *Processing Natural Gas, Separation of Natural Gas Liquids*. Accessed April 2011 at www.naturalgas.org/naturalgas/processing_ng.asp.

and office operations are other activities and materials that can occur at a gas plant and generate wastes.

## 10. Transportation, Pipelines and Storage

When processing of crude oil and natural gas has been completed at field production facilities or gas plants, the oil and gas are metered and sold. Treated oil that leaves the treatment system goes to oil stock tanks (sometimes called tank batteries) and is ready for sale. Solids and water continue to separate by gravity and accumulate in stock tanks. These tank bottom materials may require periodic removal. Oil in stock tanks is transported offsite for further processing or refining via pipeline, tank truck or barge. Wastes generated from onsite transfer operations include lubrication oils, filters, and drips and leaks from pumps and transfer lines. When shipping by tank truck or barge, drainage from transfer hoses can be returned to the system for reprocessing.

### 10.1. Pipelines

The US Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety (PHMSA) is the primary safety regulator of the energy pipeline system. PHMSA's regulations address the entire life cycle of pipelines. There are an estimated 165,000 miles of petroleum liquid pipelines that carry crude oil and petroleum products (such as gasoline, diesel, jet fuel, and home heating oil) throughout the United States.[87] The crude oil may be delivered from the field storage tanks via pipeline into the storage tanks at refineries. Currently, over 95 percent of natural gas used in the United States moves from well to market entirely via natural gas pipelines.[88] Natural gas pipeline networks are generally broken into three distinct systems:[89]

**Gathering Systems:** Carry natural gas from individual wells for bulk processing at a treatment facility, gas plant or to the transmission lines. There are about 20,000 miles of natural gas gathering lines.

**Transmission Systems:** Carry the processed natural gas, often over long distances, from the producing region to local distribution systems around the country. Including both onshore and offshore lines there are approximately 278,000 miles of natural gas transmission lines.

**Local Distribution Systems:** Deliver natural gas into our homes, businesses and power plants.

Natural gas pipelines are generally smaller in diameter than petroleum pipelines. Pipelines in the gas gathering and distribution systems range from 6" to 16" in diameter, with certain segments as narrow as a half inch. The pipes making up the interstate

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[87] API. Industry Sector, Pipeline. Accessed April 2011 at www.api.org/aboutoilgas/sectors/pipeline/index.cfm.
[88] *See* API, "Adventures in Energy: Natural Gas Pipelines" accessed April 2011 at www.adventuresinenergy.org/Natural-Gas-Pipelines/index.html, *and* Pipeline 101, "Overview, Natural Gas Pipelines" accessed April 2011 at www.pipeline101.com/Overview/natgas-pl.html.
[89] Natural Gas Suppliers Association. NaturalGas.org, *The Transportation of Natural Gas*. Accessed April 2011 at www.naturalgas.org/naturalgas/transport.asp.

transmission system range in diameter from 16 to 48 inches.[90] Transportation pipelines are usually referred to as transmission lines by the US Department of Transportation.

### 10.1.1. Construction

Prior to initiation of construction, significant design, permitting, and regulatory work, and feasibility studies, must be completed. The entire length of the pipeline route is evaluated for environmental considerations as well as potential issues that may hinder the actual installation. The project team must assure the pipeline will meet federal and state requirements, respond to local concerns, and obtain necessary permits. Land or right-of-way agents, hired by the pipeline operator, work with potential landowners to secure easement rights to place the pipeline along the selected route.

Installation of the pipeline is completed in stages. The route is first cleared of any removable obstacles such as brush, trees, and boulders and the pipe is prepared in 40 to 80 foot segments adjacent to the intended route. Trenches can be dug to a depth of five to six feet, allowing the pipe to be at least 30 inches below the surface, or deeper in road or water body crossings. If the pipeline needs to go under a river or road, directional drilling may be used to create the pathway rather than an open trench. The pipe is then welded together and shaped to fit the curvature, if any, of the trenches and is eventually lowered into the trench. An initial integrity test is done after the pipe is placed in the trench where water is sent into the line at pressures higher than the future intended pressures of the gas or liquids.

After installation of the pipeline is complete, environmental remediation is conducted to restore the area to its original state. This includes revegetation as well as replacing any manmade items that were moved such as fences.[91]

### 10.1.2. Stormwater Controls

Disturbed areas associated with pipelines acting as feeders to or from well pads or other field facilities are considered under a common plan of development in relation to stormwater in certain states. Pipelines that are part of a regional network, such as transmission lines, are considered on a separate basis. The stormwater plans for pipelines are similar to those for general pad construction, with the intent of protecting surface water. Specific best management practices (BMPs) exist based on the situations encountered in each type of pipeline location.

### 10.1.3. Pipeline Inspection and Leak Detection

Pipelines are inspected with tools called pigs, or pipeline inspection/cleaning gauges. These cylindrical or spherical devices are introduced into the line through a pig trap and enter the flow of hydrocarbons without disrupting the product movement.

Pigs can have several different purposes and are fitted with different equipment for each purpose. Scrapers on a pig can clean the line by scraping the inside of the pipeline and pushing the debris ahead. Inspection or smart pigs evaluate the integrity of the pipeline by inspecting from the inside of the line, to help predict when maintenance and repairs

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[90] Ibid.

[91] Ibid. *and* Interstate Natural Gas Association of America (INGAA), *Pipelines 101: Pipeline Construction, How are Pipelines Built?* Accessed April 2011 at www.ingaa.org/cms/33/1339/65.aspx.

may be needed. The inspection information includes pipeline diameter, curvature, bends, temperature, pressure and any metal loss. The two techniques are magnetic flux measurements detecting leakage, corrosion, or flaws in the pipeline and ultrasonic inspection to measure the thickness of the pipe wall. Pig use varies from pipeline to pipeline based on volumes of flows and characteristics of the pipeline.[92]

There are a number of different leak detection technologies, some internal to the pipeline and some external as described below.[93]

In the United States, Forward-Looking InfraRed (FLIR) technology has been adapted and utilized for leak detection and in Alaska to screen the extent of a spill under snow cover. Hand held, vehicle mounted and aircraft mounted infrared cameras can be utilized. These systems can detect the difference in the temperature when the fluids in the pipeline are warmer than the ambient temperature conditions.[94] (FLIR technology has also been used in the arctic to locate active Polar Bear dens so that production and exploration operations can be conducted without disruption of this protected animal species.)

Computational Pipeline Monitoring (CPM) leak detection systems utilize sensitive metering to measure the key parameters of the fluid entering the pipeline and the fluid leaving the pipeline. The key parameters are typically flow rate, temperature, pressure and sometimes fluid density. The sensitivity of a CPM leak detection system depends on the accuracy and the stability of the measurement instruments that measure each of the fluid parameters. For a typical pipeline, six to eight separate instruments are required to collect the data for a leak detection system. Each measuring instrument can drift over time. In a leak detection system, the instruments are calibrated on a periodic basis to correct for the drift. During the time between calibrations, the instruments can drift to the point where false alarms are generated. Advances in software are allowing the leak detection systems to recognize instrument drift and correct for that drift. This allows for fewer false alarms and for greater sensitivity to actual leaks.

### 10.1.4. Compressor Stations for Natural Gas Pipelines

Natural gas can travel through literally thousands of miles of pipeline in the journey from the well to the end user. Compressor stations are placed at key intervals (usually every 40 to 100 miles) along the pipeline network keep the natural gas moving evenly and reliably.[95] The natural gas enters the compressor station, where it is compressed by a turbine, motor, or engine.

A reciprocating compressor uses a piston to reduce the volume of its compression chamber, increasing the pressure of the gas inside. When the outlet valve opens, the pressurized gas rushes out into the next section of the pipeline. Most reciprocating

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[92] Rigzone. Training, How it Works, *How Does Pipeline Pigging Work?* Accessed April 2011 at http://www.rigzone.com/training/insight.asp?insight_id=310&c_id=19.

[93] State of Alaska, Dept. of Environmental Conservation. *Technical Review of Leak Detection Technologies, Volume 1, Crude Oil Transmission Pipelines* (Sept. 30, 1999). Accessed April 2011 at www.dec.state.ak.us/spar/ipp/docs/ldetect1.pdf.

[94] See examples at State of Alaska, Dept. of Environmental Conservation, Division of Spill Prevention and Response (SPAR), Prevention and Emergency Response Program. Accessed April 2011 at www.dec.state.ak.us/spar/perp/index.htm.

[95] Natural Gas Suppliers Association. NaturalGas.org, *The Transportation of Natural Gas.* Accessed April 2011 at www.naturalgas.org/naturalgas/transport.asp.

compressors are powered by natural gas drawn directly from the line. Natural gas pipelines also employ turbine compressors, which are similar in design to the jet engines found on commercial aircraft. In a few limited circumstances, where strict air emission rules require, pipelines can use compressors powered by electric motors.

Compressor stations usually contain some type of liquid separator, much like the ones used to dehydrate natural gas during its processing. These separators consist of scrubbers and filters that capture any liquids or other unwanted particles from the natural gas in the pipeline. The gas is usually filtered before compression and helps ensure that the natural gas in the pipeline is as pure as possible.

#### 10.1.5. Pump Stations for Liquid Lines

Petroleum liquids, like natural gas, lose forward momentum as they travel through the pipeline systems. To handle this problem and allow for additional monitoring of the liquids, pumping stations are positioned along the length of the lines to adjust the pressure as needed. Several types of pumps may be used at the stations, depending on what is needed. A full head pump has impellers in a series and one inlet and outlet. The half stage pump has two impellers in parallel, with two inlets and outlets. Half stage pumps are capable of handling twice the flow of full head pumps, but only produce half the pressure rise. The pumping stations can have storage facilities for the liquids, and have booster pumps on location to transfer liquids from storage into the line.[96]

### 10.2. Bulk Storage and Liquefied Natural Gas

Production rates and pipeline throughput are relatively fixed, but demand for natural gas is significantly higher during the winter months. This makes delivery-side storage capacity essential to assuring a steady, reliable supply of natural gas when consumers need it most.

Natural gas is most often stored in depleted (empty) natural gas or oil fields. These underground formations have already proven they can securely trap and contain natural gas, so they make useful reservoirs for natural gas delivered through the interstate pipeline. Natural gas may also be stored in underground salt caverns or geologic formations whose walls are impermeable to natural gas.

There are over 100 natural gas utilities that liquefy natural gas for aboveground storage. This is not an unusual practice and it offers another safe, proven natural gas storage alternative. Liquefied natural gas is also proving to be an important new option for transporting natural gas from regions not served logistically or economically by pipelines.

The liquefied natural gas is stored in insulated storage tanks that are designed to maintain an appropriate temperature to minimize evaporation. Some boil off of gases does occur, and these gases are collected and used as fuel source for the facility. Liquefied natural gas is heated back to gaseous state and transported as needed.[97]

### 10.3. Trucking

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[96] Rigzone. Training, How it Works, *How do Pumping Stations Work?* Accessed April 2011 at www.rigzone.com/training/insight.asp?insight_id=344&c_id=19.

[97] The California Energy Commission. *Liquefied Natural Gas, Frequently Asked Questions About LNG*. Accessed April 2011 at http://www.energy.ca.gov/lng/faq.html#600.

Petroleum and petroleum products can be trucked at various stages in the production, processing, and delivery of the products. In some producing fields, trucks are used to move the crude oil from storage tanks near the wells in the field to larger storage tanks at transfer stations.

### 10.4. Transfer Stations

Transfer stations are the points where production from various wells is collected through a pipeline gathering system or other transportation method, such as trucks for the oil. Some of these stations can treat the hydrocarbons to best suit the requirements for the next phase of transportation, such as dehydrating gas to meet the regional pipeline requirements.[98]

### 10.5. Natural Gas Control Stations and SCADA Systems

Natural gas pipeline companies have customers on both ends of the pipeline: the producers and processors that input gas into the pipeline and the consumers and local gas utilities that take gas out of the pipeline. Centralized gas control stations collect, assimilate, and manage data received from monitoring and metering or compressor stations all along the pipe in order to ensure that all customers receive timely delivery of natural gas and monitor and control the natural gas that is traveling through the pipeline. Most data received by a control station is provided by what is called a Supervisory Control and Data Acquisition (SCADA) systems. Flow rate through the pipeline, operational status, pressure, or temperature readings are used to assess the status of the pipeline at any one time. These systems also work in real time resulting in minor gaps between the measurements taken along the pipeline and information being transmitted to the control station. This enables quick reactions to equipment malfunctions, leaks, or any other unusual activity along the pipeline. SCADA systems can incorporate the ability to remotely operate certain equipment along the pipeline, including compressor stations, allowing engineers in a centralized control center to immediately and easily adjust flow rates in the pipeline.[99]

## 11. Worker Health and Safety

The health and safety of workers in the oil and gas industry is of key importance. The practices for each stage of operations vary based on potential exposure to hazards in the various environments in which the industry operates. Depending on the location, workers need protection from natural conditions, including weather and temperature extremes and wildlife, such as snakes, bees and wasps, or bears. Many of the operational hazards may be mitigated or reduced with engineering controls, such as routing gas to a flare for safe combustion, and alarms used to alert workers of hazards.

### 11.1. Protective Equipment

The below list is by no means exhaustive, but shows some examples of general safety equipment used (personal protective equipment or PPE), some of which are regulated by federal or state regulations:

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[98] See, for example, Natural Gas Supply Association. NaturalGas.org, *The Transportation of Natural Gas, Compressor Stations*. Accessed April 2011 at www.naturalgas.org/naturalgas/transport.asp

[99] Natural Gas Supply Association. NaturalGas.org, *The Transportation of Natural Gas, Control Stations and SCADA Systems*. Accessed April 2011 at www.naturalgas.org/naturalgas/transport.asp.

- Breathing apparatus (from masks and respirators to self contained breathing apparatus);
- Eye protection or goggles, and/or eye wash stations;
- Protective clothing, gloves, hard hats;
- Hearing protection;
- Spark proof tools; and
- Personal or area hydrogen sulfide (H2S) monitors.

### 11.2. Safety and Health Regulations, Policies and Practices

Oil and gas employers are responsible for the work environment where employees engage in activities on their behalf. The Occupational Safety and Health Act of 1970 (OSHA) and the regulations implementing OSHA mandate that employee exposures to recognized chemical, physical and biological hazards be less than occupational maximum limits for the period of interest. These mandates may be contained as regulations in 29 CFR Part 1910 or 1926. The requirements are risk-based, and are prescriptive or performance standards. The act states that:

- Each employer shall furnish to each of his employees employment and a place of employment which are free from recognized hazards that are causing or are likely to cause death or serious physical harm to his employees. (29 U.S.C. § 654, 5(a)1)
- Each employer shall comply with occupational safety and health standards promulgated under this act. (29 U.S.C. § 654, 5(a)2)
- Each employee shall comply with occupational safety and health standards and all rules, regulations, and orders issued pursuant to this Act which are applicable to his own actions and conduct. (29 U.S.C. § 654, 5(b))

As such, all employers in the U.S. whose operations are covered by the OSH Act and regulations are required to evaluate the workplace for hazards and, depending on the levels found, implement exposure controls. The ultimate purpose is to protect employees against hazards that are known to cause harm - either immediately, such as skin contact with concentrated sulfuric acid, or later, such as contracting leukemia due to repeated inhalation of benzene vapor over a working career. Many of the more common exploration and production health and safety issues addressed by OSHA requirements are reviewed online by OSHA.[100]

Other government and non-government resources for profiling hazards in the workplace include: the National Institute of Occupational Safety and Health (NIOSH), and the American Conference of Governmental Industrial Hygienists (ACGIH). The study of measuring the workplace environment, exposure profiles and prescribing control methods is known as Industrial Hygiene and is a part of occupational health - the "H" in the acronyms, including HSE.

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[100] Occupational Safety & Health Administration. *Oil and Gas Well Drilling and Servicing eTool*. Accessed April 2011 at www.osha.gov/SLTC/etools/oilandgas/index.html.

### 11.3. Limiting Exposure to Chemicals and Emissions

Not all workplaces have the same exposure profile. Because of this, the control method(s) chosen by employers may differ throughout the industry, but must be fully effective against the contaminant in the levels at which it is present. While extremely low levels of certain chemicals may not require any type of control, higher levels of those chemicals may require the employee be completely separated from the hazardous work environment.

The mere presence of a hazard in the workplace may not always translate into an exposure that must be controlled. To cause disease or an undesired outcome, the hazard must somehow enter or cause damage to the body, and this is sometimes referred to as a dose. The potential for a dose must be present and several things affect the dose: the magnitude of the hazard present, the exposure route, and the duration and frequency of employee contact with the hazard. The typical exposure routes for chemical hazards are by inhalation, absorption, injection (such as a cut) or ingestion. Physical hazards such as ionizing radiation from naturally-occurring material typically cause damage by penetration. Exposure may be controlled (and minimized) by addressing any or all of the factors that affect the dose. Typical control strategies may include the use of local exhaust ventilation, personal protective equipment such as respirators, hearing protection or gloves, substitution of the hazardous substance with another which is less hazardous, or by minimizing worker contact with the hazard through work site procedures.

Hazards enter the workplace because they either exist as part of the materials that are part of the work or they are purchased and exist in products used to operate the business. In the oil and gas industry, most workplace hazards fall under the former category because of the naturally occurring materials in the reservoirs, crude oil and natural gas. Common contaminants of many oil and gas production streams include: BTEX (Benzene, Toluene, Ethylbenzene, Xylene), Hydrogen sulfide, and naturally-occurring radioactive material (NORM - daughters of 226/228Ra). Other hazards are created by materials and chemicals used by the business and its operations. They may include: Noise (prime movers or equipment), Sulfur dioxide (a flare), or Lead (pipe thread compound). Such hazards are subject to control by substitution / elimination and protecting the workers from exposure with the proper work practices and use of personal protective equipment (PPE).

The availability of chemical hazards in the workplace may be affected by the temperature and pressure at which they are handled. For example, higher liquid handling temperatures will vaporize more hydrocarbons in a mixture than will handling the same liquid at a lower temperature. More vaporized hydrocarbons may translate into higher worker exposures. Therefore, the process utilized by the business may affect the exposure profile as well, and controlling these types of conditions is another strategy to be used to protect workers.

## 12. Abandonment and Final Reclamation

After all the economically recoverable oil and gas has been produced at a well site, or if a well fails to produce (such as a dry hole), the well is plugged and abandoned and the site is reclaimed. Federal land and state oil and gas agencies have rules that specify how the well is plugged, soil reclaimed and other environmental and safety protections completed to avoid future problems.[101] All final reclamation work is required to be completed within a specified time after plugging a well. Final reclamation does not necessarily require full ecological restoration, but rather the short term stability and visual, hydrological, and producing potential to allow the site to naturally return to its original state. An operator is typically required to:

- Remove all production equipment and debris;
- Evenly redistribute stockpiled topsoil over the site to provide a seedbed for the revegetation efforts;
- Remove or treat any remaining production waste or contamination from spills or releases following state regulations;
- Ensure pits are free of oil or other liquids and solid waste prior to filling, liners are removed complete or to the solids line and buried in a manner that prevents future reemergence, and production pits are backfilled by replacing the soils in the original position;
- Correct subsidence over closed production pit locations by adding additional topsoil as mounds;
- Close access roads to plugged and abandoned wells and associated facilities;
- Re-grade and re-contour the well site and access roads to blend seamlessly with the surrounding environment;
- Perform compaction removal, restoration, and revegetation on well sites and access roads to the same standards as those for interim reclamation on both Crop Land and Non-Crop Land; and
- Comply with all state regulations unless a surface owner waiver or agency variance is obtained.

Plugging and abandoning a well involves filling the well casing with cement and removing the wellhead, pump jack, tanks, pipes, and other facilities and equipment. For abandonment of pipelines and flowlines, the lines are flushed and any remaining fluids are properly disposed. Near surface lines that could become exposed due to erosion are removed, with deeper lines remaining in place if the overseeing agency approves. If cleaned of materials and it can be done safely, leaving the pipeline in place avoids disturbing the surface again.

Final well plugging and abandonment of remote wells takes an incredible amount of planning to minimize the environment impact, particularly in the Arctic. Ice roads or track vehicles are generally used to mobilize equipment and personnel to abandon wells in the open arctic areas. Operational steps and mechanical barriers are planned in advance to reduce the amount of equipment needed to haul to the site. All fluids that are recovered are hauled out or injected back into an approved disposal well. By law, all

[101] BLM *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* (2007) 4th Edition (Gold Book). Accessed April 2011 at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/gold_book.html.

wellheads are cut below tundra grade and removed from the site. Methods to further reduce the impact and restore the tundra and wetlands continue to be studied.[102]

**13. Personnel Management and Work Force Facilities**

Exploration and Production operations, from exploration through transportation, can require a large workforce and 24 hour staffing. In remote areas, a company may assemble or construct and use a work force facility to minimize miles traveled and associated costs and impacts. Such facilities will generate materials and solid waste. Work force facilities typically consist of personnel accommodations, dining facilities, vehicle fueling stations, aircraft fueling stations, maintenance areas, parking areas, wastewater treatment facilities, and sewage systems.

[102] See, for example, Tatiana Minayeva and Tatiana Bobrovitskaya, "Arctic Tundra Restoration Partnership Project, Shell and Wetlands International." Presented at the 4th Arctic Frontiers Conference, Tromso, Norway, January 24-29, 2010. Accessed April 2011 at www.wetlands.org/Portals/0/Shell/Arctic FrontiersMinaevaBobrovitskaya_fin.pdf.