APPENDIX A

OIL AND GAS OPERATIONS

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A1.0 GEOPHYSICAL EXPLORATION

Oil and gas reservoirs can be discovered by either direct or indirect exploration methods. Direct methods would include mapping of surface geology, observing seeps, and gathering information on hydrocarbon shows observed in drilling wells. Indirect methods, such as seismic, gravity, and magnetic surveys, are used to delineate subsurface features that may contain oil and gas that are not directly observable.

A1.1 Gravity Surveys

Gravity surveying uses micro-variations in the earth's gravitational field that may be caused by the differences in rock densities to map subsurface geologic structures (Robinson and Coruh, 1988). These surveys are generally of low resolution due to the many data corrections required (e.g., terrain, elevation, latitude, etc.) and the complexity of subsurface geologic structures. The instrument used for gravity surveys is a small portable device called a gravimeter. Generally measurements are taken at many points along a linear transect and the gravimeter is transported either by backpack, helicopter, or off-road vehicle. Surface disturbance associated with gravity prospecting is minimal.

A1.2 Geomagnetic Surveys

Magnetic prospecting is most commonly used for locating metallic ore bodies, but is used, to a limited extent, in oil and gas exploration. Magnetic surveys use an instrument called a magnetometer to detect small variations in the earth's magnetic field caused by mineralization or lithologic variations in the earth's crust (Robinson and Coruh, 1988). These surveys can detect large trends in basement rock and the approximate depth to those basement rocks, but, in general, they provide little specific data to aid in petroleum exploration. Many data corrections are required to obtain reliable information and maps generated often lack resolution and are considered preliminary. Magnetometers vary greatly in size and complexity and, in general, most magnetic surveys are conducted from the air by suspending a magnetometer under an airplane. Magnetic surveys conducted on the ground are nearly identical to gravity surveys in that surface disturbance is minimal.

A1.3 Reflection Seismic Surveys

Reflection seismic prospecting is the best and most popular indirect method currently utilized for locating subsurface structures that may contain hydrocarbons. Seismic energy (shock waves) is induced into the earth using one of several methods at a location called a source point or shot point. As these waves travel downward and outward, they encounter various rock strata that transmit seismic energy at different velocities **(Figure A-1)**. As the wave energy encounters the

Figure **A-1** Seismic Survey

interfaces between rock layers that transmit seismic energy at different velocities, some of the seismic energy is reflected upward and some of the energy continues down into the earth. Sensing devices, commonly called geophones, are placed on the surface to detect these reflections of energy. The geophones are wired in groups and are connected to a data recording truck that stores the data (Robinson and Coruh, 1988). The geophone groups, while all connected to the data recorder truck, may be laid out in lines thousands of feet long. The time required for the shock waves to travel from the source point down to a given reflector and back to the geophone can be related to depth. After the data are acquired, the digital information is processed with a computer. The end product of the seismic processing is a seismic section that presents the strata or structures below the surface **(Figure A-1)**. The seismic section is an image of the reflected seismic energy and is not the same as a geologic cross-section that is constructed from data derived directly from wells or outcrops.

There are several methods available to induce shock wave energy into the earth, but for onshore oil and gas exploration, there are two methods used to create the seismic energy. One method of inducing seismic energy is called vibroseis (Robinson and Coruh, 1988). The vibroseis method uses hydraulic actuated devices called vibrator pads mounted on trucks/buggies to pound or thump on the surface of the ground to create shock wave energy. On a typical survey, usually four to five “thumper” trucks/buggies are used, each equipped with 4-foot square vibrator pads. At a location called the source point, the trucks/buggies are spaced at specified intervals and the vibrator pads are simultaneously triggered to vibrate or thump on the ground. The thumping will last for 10 to 30 seconds. The information is recorded and then the trucks move to the next source point and the process is repeated. As the trucks/buggies move to the next source point, groups of geophones are picked up and moved leap-frog fashion to the end of the line. Less than 50 square feet of surface area is required to operate the equipment at each source point and the geophone groups are transported by vehicle when moved, but have to be laid out and picked up by hand-labor.

The shot-point method of creating shock wave energy utilizes truck-mounted drills that drill small-diameter holes to depths of up to 200 feet. Drilling water, when needed, is usually obtained from the nearest source. Four to twelve holes are drilled per mile of line. An explosive charge is placed in the hole, covered, and detonated. Different hole depths require different charge sizes to be used. When shot holes are “covered,” the holes are plugged with the drill cuttings that are tamped back in to the hole above the explosive to secure the charge and to reduce the potential for the hole to blow-out. Water-bearing zones are sealed with bentonite gravel that is either poured directly down the hole or is placed down-hole in a biodegradable cardboard tube. In rugged topography, a portable drill is sometimes carried in by helicopter. Charges are placed in the hole as in a truck-mounted operation. Another portable technique is to carry the charges in a helicopter and place the charges on wooden sticks, or lath, approximately 3 feet aboveground. The charges used weigh 2.5 to 5 pounds. Usually 10 charges in a line on the ground are detonated at once. In remote areas where there is little known subsurface data, a series of short seismic lines may be required to determine the attitude of subsurface formations. After this, seismic lines will be aligned relative to the regional structure to make seismic interpretation more accurate.

In seismic surveys, several seismic lines are shot and the distances of the lines and the spacing between the lines are predetermined based on the purpose of the survey. The seismic lines are often separated on a 1- to 2-mile grid spacing. Although alignment may be fairly critical, spacing of the lines can often be changed 0.25 mile on a 1-mile grid before the results will significantly affect the investigation program. At predetermined source points, short cross-spreads can be laid out perpendicular to the main line to obtain higher accuracy in the survey (Robinson and Coruh, 1988).

A variation of this technique is the three-dimensional (3-D) seismic profile survey. The methods of generating the seismic waves are the same as those used in conventional seismic surveys. This type of survey differs from the more common two-dimensional survey in the greater number of datapoints and the closer spacing of the lines. Three-dimensional seismic surveys are more computer intensive for the processing of the data, but 3-D surveys result in a more detailed and informative subsurface image (with an accompanying higher cost). The orientation and arrangement for the components in 3-D seismic surveys are less tolerant of adjustments to the physical locations of the lines and geophones, but they can be more compact in aereal extent. Three-dimensionsal surveys are commonly used in established field areas to help better define structure, stratigraphy, and movement of fluids between wells or used to focus on a promising exploration target in order to lessen risk in locating a exploratory drill location.

A typical seismic operation conducting a shot-point survey may utilize a 10- to 15-person crew operating five to seven trucks. Under normal conditions, 3 to 5 miles of line can be surveyed each day using the shot-point method. The vehicles used for a drilling program include several heavy truck-mounted drill rigs, water trucks, a computer recording truck, several light pickups or stake-bed trucks for the surveyors, shot hole crew, geophone crew, permit man, and party chief.

Public roads and existing private roads and trails are used when available. Off-road cross-country travel may be necessary to conduct the survey. Road graders or bulldozers may be required to provide access to remote areas. Concern about unnecessary surface disturbance has caused government and industry to use care when planning surveys. As a result, earth-moving equipment is now only rarely used in seismic exploration work. Several trips may be made along a seismic line; this can cause a well-defined two-track trail. To reduce impacts, crews operating in the RMPPA are required to deviate from straight lines, to spread vehicle operations out, and not retrace the track/route traveled by a preceding geophysical vehicle or other geophysical equipment. This practice substantially reduces the creation of new two-track trails and reduces impacts.

Each of the foregoing methods have inherent strengths and weaknesses and the exploration team must decide which method is the most practical with regard to surface constraints (such as topography), but will still produce information that can be useful for the particular study. Extensive computer processing of the raw data is required to produce a useable seismic section from which geophysicists may interpret structural relationships to depths of 30,000 feet or more. The effective depth of investigation and resolution are determined to some degree by which method is used. In the last 20 years, the technology has progressed so that better resolution has been obtained from greater depths and to be able to discern structures hidden beneath salt layers or overthrust blocks.

A1.4 Permitting Geophysical Surveys

Geophysical operations on and off an oil and gas lease are reviewed by the federal surface management agency (SMA), which can include the U.S. Bureau of Land Management (BLM), Bureau of Reclamation, or U.S. Forest Service (USFS), as appropriate. Good administration and surface protection during geophysical operations can only be accomplished through close cooperation of the operator and the managing agency.

In the process of permitting geophysical surveys, the responsibilities of the geophysical Operator and the Field Office (FO) Manager during geophysical operations are as follows (BLM and USFS, 1989):

1. Geophysical Operator – An operator is required to file with the FO Manager a “Notice of Intent to Conduct Oil and Gas Exploration Operations" or (NOI). The NOI shall include a map showing the location of the line, all access routes, and ancillary facilities. The party filing the NOI shall be bonded. A copy of the bond or other evidence of satisfactory bonding shall accompany the NOI and a detailed plan of operations also is routinely required.

   For geophysical operation methods involving surface disturbance, a cultural resources survey also may be required. A pre-work field conference may be conducted. Earth-moving equipment shall not be used without prior approval. Upon completion of operations, including any required rehabilitation, the operator is required to file a "Notice of Completion of Oil and Gas Exploration Operations."

2. FO Manager – The FO Manager contacts the operator after the NOI is filed to apprise the operator of the practices and procedures to be followed prior to commencing operations on BLM-administered lands. Then FO Manager completes a final inspection and notifies the

operator if the terms and conditions of the NOI have been met or that additional action is required. Consent to release the bond or termination of liability will not be granted until the terms and conditions have been met.

A1.5 State Standards for Seismic Surveys

In Wyoming, seismic survey operators must comply with Wyoming Oil and Gas Conservation Commission (WOGCC) rules (WOGCC, 2001). The standards for seismic operations are found in WOGCC Rules, Chapter 4, Section 6, Geophysical/Seismic Operations. The rules cover permitting, bonding, shot-hole drilling, and shot-hole plugging.

A1.6 Mitigation of Conflicts with other Resources or Activities

Seasonal restrictions may be imposed to reduce conflicts with wildlife, watershed damage, and hunting activity. The most critical management practice is compliance monitoring during and after seismic activity. Compliance inspections during the operation ensure that stipulations are being followed. Compliance inspections upon completion of work ensure that the lines are clean and the drill holes are properly plugged.

A2.0 FLUID MINERALS LEASING

The Mineral Leasing Act provides that all public lands are open to oil and gas leasing unless a specific order has been issued to close an area. Leasing procedures for oil, non-coalbed methane (CBM) gas, and CBM are the same. Based on the Federal Onshore Oil and Gas Leasing Reform Act of 1987, all leases must be exposed to competitive interest. Lands that do not receive competitive interest will be available for noncompetitive leasing for a period not to exceed 2 years. Competitive sales will be held at least quarterly and by oral auction. Competitive leases are issued for a term of 5 years and noncompetitive leases are issued for a term of 10 years. If the lessee establishes hydrocarbon production, the competitive and noncompetitive leases can be held for as long as oil and/or gas are produced. The Federal Government receives yearly rental fees on non-producing leases. Royalty on production is received on producing leases, one half of which is returned to the State of Wyoming.

A3.0 DRILLING PERMIT PROCESS

A3.1 Permitting

A federal lessee or operator is governed by procedures set forth by the Onshore Oil and Gas Order No. 1, "Approval of Operations on Onshore Federal and Indian Oil I and Gas Leases," issued under 43 Code of Federal Regulations (CFR) 3164 (BLM, 1983). Operating Order No. 1 lists the following as pertinent points to be followed by the lessee or operator: notice of staking (NOS); application for permit to drill (APD), which includes a multi-point surface use and operations plan; approval of subsequent operations; well abandonment; conversion to water well; responsibilities on privately owned surface; and reports and activities required after well completion. The permitting process for drilling is the same for oil, non-CBM gas, and CBM.

The lessee or operating company selects the location of a proposed drill site. The selection of the site is based on well location and spacing requirements, the subsurface geology as interpreted by the operator's geoscientists, and the topography. Well location and spacing requirements are established by the WOGCC. Each well is to be drilled within a given distance from the center of a legal subdivision (such as a quarter/quarter of a section or quarter section, depending on the spacing assigned to the particular area). A proposed location may be moved within the tolerance established by rule or outside the designated tolerance with a location exception granted by the WOGCC (WOGCC, 2001).

There are two procedural options for obtaining approval to drill a well **(Figure A-2)**. After an operator decides to drill a well, it must decide whether to submit a NOS or an APD. The NOS process, if properly planned and coordinated, can expedite permit approval. The APD process is more familiar to industry in general and does not require as much up-front coordination as the NOS (BLM and USFS, 1989). In either case, no surface activity can be conducted until the well is approved by the BLM.

The procedure for the NOS is as follows:

1. The operator submits an outline of the plan to the BLM, which includes a location map and sketched site plan. The NOS is then used as a document to review any conflicts with known critical resource values.

2. The BLM and operator conduct an on-site inspection. The NOS provides preliminary site-specific information, which will be reviewed during the on-site inspection. As a result of this inspection and review, additional information that is required for the APD process is identified.

Figure **A-2** Federal Permitting Process

3. An APD is submitted based on the findings of the inspection and review of potential conflicts.

The APD procedure is as follows:

1. The operator may submit a completed APD in lieu of the NOS.

2. A field inspection is held with the operator and any other interested party. The purpose of the field inspection is to evaluate the operator's plan and assess the situation for possible impacts (surface and subsurface) and to formulate resource protection stipulations.

3. The APD is reviewed with respect to the field inspection.

To lessen environmental impacts, a site may be moved, reoriented, or reconfigured, within certain limits, at the site inspection. The proposed access road may also be rerouted. If necessary, site-specific mitigations are added to the APD for protection of surface and subsurface resource values in the vicinity of the proposed activity (BLM and USFS, 1989).

The BLM is responsible for preparing environmental documentation necessary to satisfy the National Environmental Policy Act (NEPA) requirements and provide any mitigation measures needed to protect the affected resource values.

Consideration is also given to the protection of groundwater resources. When processing an APD, the BLM's geologist is required to identify the maximum depth of usable water as defined in Onshore Oil and Gas Order No. 2 (BLM, 1988). Usable water is defined as that water containing 10,000 parts per million (ppm) or less of total dissolved solids (TDS). Water quality is protected by running surface casing to a depth prescribed by the geologist.

Determining the depth to fresh water requires specific water quality data in the vicinity of the proposed well or geophysical log determination of water quality. Information on water quality is obtained from analytical data from nearby water wells (if available) or from geophysical well logs (if available). If water quality data or well logs from nearby wells are not available, the depth to the deepest fresh water zone in wells within a 2-mile radius of the proposed well is determined. Surface casing for the proposed well is required to be set below the deepest fresh water zone found in nearby water wells or to reach a depth below the reasonably estimated level of usable water that will be protective of usable water.

When final approval is given by the BLM, the operator may commence construction and drilling operations. Approval of an APD is valid for 1 year. If construction does not begin within 1 year, the stipulations must be reviewed prior to approving another APD (BLM and USFS, 1989).

A3.2 Surface Disturbance Associated With Drilling

Upon receiving approval to drill the proposed well, the operator moves construction equipment over existing roads to the point where the access road will begin. Surface disturbing activities for oil, non-CBM gas, and CBM are similar except the typical CBM drilling location generally requires less surface area than for oil and gas wells. Road and drill-pad construction must conform to the standards set forth by the BLM. The information provided on construction in this section is taken from the construction standards manual ("The Gold Book") published jointly by the BLM and USFS (1989). Generally, the types of construction equipment used include bulldozers (track-mounted and rubber-tired), scrapers, and roadgraders. Equipment is transported to the construction area by semi-trailer trucks over public and private roads. Existing roads and trails may be improved in places and occasionally culverts and cattleguards are installed, if required.

The lengths of the access roads vary. Generally, the shortest feasible route should be selected to reduce the haul distance and construction costs. Environmental factors or the surface landowner's wishes may dictate a longer route. In rough terrain, the type of construction is called sidecasting (using the material taken from the cut portion of the road to construct the fill portion); slightly less than one half of the road bed is placed on a cut area and the remainder is placed on a fill area. Roads are usually constructed with a 14-foot (single lane) or 24-foot (double lane) running surface (in relatively level terrain). Soil texture, steepness of the topography, and moisture conditions may dictate surfacing the access road with gravel in some places, but generally not for the entire length. The total acreage disturbed for each mile of access road constructed varies significantly with the steepness of the slope.

During construction of well locations, all soil material suitable for plant growth topsoil is first removed from areas to be disturbed and stockpiled in a designated area. Sites on flat terrain typically require minimal earthwork including the removal of topsoil and vegetation. Drilling sites on ridge tops and hillsides are constructed by cutting and filling portions of the location. The majority of the excess cut material is stockpiled in an area that will allow it to be easily recovered for rehabilitation. It is important to confine extra cut material (spoil) in a stockpile rather than cast it down hillsides and drainages where it cannot be recovered for rehabilitation.

The amount of level surface required for safely assembling and operating a drilling rig varies with the type of rig, but averages 300 feet by 400 feet for a single well location. **Figure A-3** illustrates a typical oil and gas well location and **Figure A-4** depicts a typical layout of a CBM drilling location. The dimensions of a typical CBM location are smaller than oil or non-CBM gas locations because of the shallower drilling depths and smaller drilling rigs that are required. However, as deeper coal seams are developed, the drill location size will increase and may approach that of a non-CBM gas well location. A location pad for multiple wells will incrementally increase in size for each well

Figure **A-3** Schematic for a Typical Single Well Pad Layout

Figure **A-4** Typical CBM Well Pad Layout added to the location. A location could approach 500 feet by 600 feet for a location containing four wells. The well pad should be constructed such that the drilling rig will sit on solid ground and not on fill. This ensures that the foundation of the drilling derrick is on solid ground and prevents it from leaning or toppling due to settling of uncompacted soil.

In addition to the drilling platform, a reserve pit is constructed, usually square or rectangular but sometimes in other shapes, to accommodate topography. Reserve pits are used to store water, drilling fluid, and drill cuttings. Generally, the reserve pit is 8 to 12 feet deep, but may be deeper to compensate for smaller length and width or deeper drilling depths. Generally, the deeper the well, the larger the reserve pit. If possible, pits should be constructed on cut material and not fill. If constructed on fill, there is a high potential for leakage. Depending on specific site conditions, the WOGCC or BLM may require that pits be lined with suitable plastic material to prevent leakage of pit fluids into shallow aquifers. Pits may be divided into compartments separated by berms for the proper management of generated waste (e.g., drill cuttings, mud, water flows).

Depending on how the drilling location is situated with respect to natural drainages, it may be necessary to construct water bars or diversions. The area disturbed for construction and the potential for successful revegetation depends largely on the steepness of the slope.

Water for drilling is hauled to the rig storage tanks or transported by surface pipeline. Water sources are usually rivers, wells, or reservoirs. Occasionally, water supply wells are drilled on or close to the site. The operator must obtain a permit from the Wyoming State Engineer for the use of surface or subsurface water for drilling. When the BLM holds the water permits for surface water (stock ponds), it must also approve such use. During drilling operations, water is continually transported to the rig location. Approximately 40,000 barrels or 1,680,000 gallons of water are required to drill an oil or gas well to the depth of 9,000 feet. Water demand may vary depending on the specific subsurface conditions that are encountered during the drilling of the well.

Drilling activities begin as soon as practically possible after the location and access road have been constructed. The drilling rig and associated equipment are moved to the location and erected. Moving a drilling rig requires moving 10 to 25 truck loads (some over legal weight, height, and width) of equipment over public highways and private roads. The derrick, when erected, can be as much as 160 feet high, but derrick heights will vary depending on the depth and weight capacity of the rig.

A3.3 Issuance of Rights-of-Way

Rights-of-way are required for all facilities, tank batteries, pipelines, truck depots, powerlines, and access roads that occupy federally owned land outside the lease or unit boundary. When a third-party contractor (someone other than the lease operator or the federal government) constructs a facility or installation on or off the lease, a right-of-way also is required. Rights-of-way on federal lands are issued by the BLM.

A3.4 Drilling Operations

A3.4.1 Oil and Non-CBM Gas

A3.4.1.1 Drilling Operations

Starting to drill is called “spudding in” the well. Initially, drilling usually proceeds rapidly mainly due to the unconsolidated nature of shallow formations. Drilling is accomplished by rotating special bits under pressure. While drilling, the rig derrick and associated hoisting equipment bear a great majority of the drill string weight **(Figure A-5)**. The weight on the bit is generally a small fraction of the total drill string weight. The combination of rotary motion and weight on the bit causes rock to be chipped away at the bottom of the hole. The rotary motion is created by a square or hexagonal rod, called a kelly, which is attached to the top of the drill pipe. The kelly fits through a square or hexagonal hole in a turntable, called a rotary table. The rotary table is turned by diesel or diesel-electric combination motors on the drill rig. The rotary table sits on the drilling rig floor and, as the hole advances, the kelly slides down through it. When the full length of the kelly has moved through the rotary table, drilling is stopped and the kelly is raised and an additional piece of drill pipe (or joint) about 30 feet in length is placed on top of the drill string. The top of the drill pipe is then lowered to the rotary table and held in place by devices called slips and the kelly is attached to the top of it. The slips are removed by pulling up on the pipe and drilling recommences.

Drilling fluid or mud is circulated through the drill pipe to the bottom of the hole, through the bit, up the bore of the well, and finally to the surface. When the mud emerges from the hole, it goes through a series of equipment used to screen and remove rock chips and sand-size solids. When the solids have been removed, the mud is placed into holding tanks and from the tanks it is pumped back into the well. The mud is maintained at a specific weight and viscosity to cool the bit, seal off any porous zones (protect aquifers or prevent damage to producing zone productivity), subsurface pressure control, lubrication of the drill string, clean the bottom of the hole, and bring the rock chips to the surface (Moore, 1974). There are three common types of drilling fluids: water-based, oil-based, and synthetics. Water-based muds are the most common and are largely made up of water and bentonite, a clay that has special properties used to maintain proper viscosity and other properties over a wide range of drilling conditions. Freshwater is usually used, but brine is used if salt layers are to be drilled (to prevent solution of the salt). Seawater is used for offshore drilling because of its availability. Oil-based mud is used for subsurface conditions where water may react with shale and cause caving and sloughing of the sides of the wellbore. Synthetic drilling fluids are used for special conditions and have become more common in recent years. The synthetic fluids are composed of organic polymers or other chemicals and are often designed to

Figure **A-5** Rotary Drill Rig Diagram

be environmentally benign. Additives are used to maintain the drilling mud properties for specific conditions that may be encountered during drilling. Some of the additives may be potentially hazardous, but these additives are used in relatively small amounts during drilling operations. Other additives are composed of organic materials, such as cottonseed hulls, and are not hazardous.

Another common drilling system uses the pump pressure that is used to circulate the drilling fluid to turn the bit. This type of system is called a mud-motor and essentially consists of a turbine that is part of the bottom-hole-assembly (BHA) at the bottom of the drill string (Short, 1993). The pump pressure turns the turbine that rotates the bit. There is no rotating movement in the drill string above the mud-motor. Mud–motors are used under special conditions such as directional or horizontal drilling.

Eventually, the bit becomes worn and must be replaced. To change bits, the entire string of drill pipe must be pulled from the hole, in 60-foot or 90-foot sections (stands), until the bit is brought out of the hole. The stands of drill pipe are stacked vertically in the rig derrick. The bit is replaced and then the drill string is reassembled and lowered into the hole, stand by stand, and drilling is started again. The process of removing and reinserting the drilling string is called a trip and may take up to 24 hours or more on a deep well to make a "round trip" to retrieve a worn bit. Drilling operations are continuous, 24 hours a day, 7 days a week. There are three 8-hour or two 12-hour shifts or tours (pronounced towers) a day. Pickups or cars are used for workers' transportation to and from the location.

Upon completion of the drilling, the equipment is removed to another location. If hydrocarbons are not discovered in commercial quantities, the well is called a "dry hole." The operator is then required to follow state and BLM policy procedures for plugging a dry hole. The drill site and access roads are rehabilitated in accordance with the stipulations attached to the approval of the well site (BLM and USFS, 1989).

A3.4.1.2 Casing and Cementing

Casing consists of steel pipe that is placed into the hole to prevent the collapse of the hole, to protect aquifers, and to isolate producing zones from other formations. Several strings of casing may be placed into the well that have different purposes. In the initial stages, the first casing set into the hole is called a conductor pipe. The conductor pipe is a large diameter pipe (greater than 12 inches) that is set at a fairly shallow depth (50 feet or less). The conductor pipe provides support for unconsolidated surface material. The conductor pipe is usually drilled and set in by a small auger rig prior to the set up of the drilling rig.

The next casing to be placed into the well is called surface casing. The well is drilled to a predetermined depth and the surface casing is run into the hole and cemented in place. Cementing operation involves pumping cement down through the bottom of the casing and up around the annulus (the space between the pipe and the sides of the hole). The cement is pumped up the annulus from the bottom of the casing to the surface to ensure that all potential shallow aquifers are protected and to hold the casing in place. Surface casing can be set from a couple hundred feet to over one thousand feet, depending on local requirements. Surface casing should be set to a depth greater than the deepest freshwater aquifer that could reasonably be developed. Surface casing must be large enough to accommodate one or more sets of casing strings that may be set as the well is drilled deeper.

In many cases, the next string of casing to be set in the hole is called the production string. Once the target zone is reached, the well is deepened slightly below the zone. The production string is run and cemented in place. Generally, only the bottom few hundred feet of the production string is cemented in place, enough to cover the producing zone plus enough cement above the producing zone to provide adequate protection against leakage of the reservoir into the annulus. Operators are required to cement off hydrocarbon bearing zones to prevent contamination of aquifers. Operators are also required to protect other hydrocarbon and water productive strata as directed by the WOGCC or the BLM.

For some drilling conditions, one or more intermediate casing strings may be required before the well reaches total depth. Intermediate strings are used to prevent loss of the hole while drilling deep wells, to control over-pressured zones, to protect hydrocarbon zones, to provide a point from which to drill a deviated hole, and to isolate lost circulation zones. Lost circulation occurs when the hydrostatic pressure of the mud breaks down a formation and large volumes of mud are lost into that zone. Intermediate casing is often the only way to prevent lost circulation from occurring and potential loss of the hole when drilling deep wells.

A3.4.1.3 Blowout Prevention

In the early days of drilling, no blowout prevention equipment was used. As a result, several spectacular blowouts occurred in the Resource Management Plan Planning Area (RMPPA) near La Barge. However, because of environmental, safety, and concern for conservation of oil and gas resources (prevention of waste), blowout prevention is a primary concern during well drilling. Blowout prevention begins with an understanding of the subsurface pressure regime. In normally pressured rocks, the pressure increases with depth in a relationship expressed as 0.433 pound per square inch per foot (Moore, 1974). Blowout prevention is a concern in areas of abnormally high-pressure gradients. When a drill bit penetrates an abnormally high-pressured zone, there is a risk that a blowout, or uncontrolled flow of fluids to the surface, will occur. Abnormally high pressures have several causes. The main cause of over pressures in the RMPPA is hydrocarbon generation and a sealing overburden. In the Greater Green River Basin, one cause of abnormally high pressures is the presence of basin-centered gas trapping in Tertiary and Cretaceous rocks. In the RMPPA, the depth of the overpressure depth occurs at around 8,000 to 10,000 feet (Law and Spencer, 1989).

The drilling fluid is the first line of defense against a blowout. But if abnormally high pressures are encountered, the weight of the mud itself may not be enough to hold back formation fluids. Therefore, by rule, drilling rigs must be equipped with a device called a blowout preventer (BOP). During drilling of a well, the BOP is placed on top of the surface casing string. Blowout prevention equipment is tested and inspected regularly by both the rig personnel and the inspection and enforcement branch of the BLM. Minimum standards and enforcement provisions are currently in effect as part of Onshore Order No. 2 (BLM, 1988). Well-trained rig site personnel also are a necessity for proper blowout prevention.

Through a system of hydraulically activated valves and manifolds, the BOP is designed to shut the well in and prevent the uncontrolled flow of fluids. In addition, BOPs also are designed to allow fluid to be pumped into the hole (to "kill" the well) and allow drill pipe to move in and out of the hole (Boyd, 1971).

A3.4.1.4 Formation Evaluation

One of the primary activities that occurs during the drilling of the well is the acquisition of downhole information. Formation evaluation covers a variety of data gathering and retrieving methods that include mud logging, wireline logging, formation testing, coring, and measurement while drilling (MWD) surveys. In wildcat wells (wells drilled outside of areas of established production or into deeper untested zones in established fields), it is important that quality data be obtained in order to justify the costly decision to run (or not run) production casing and complete the well. In producing areas, adequate formation evaluation is also important so that reservoir properties are understood in order to make informed decisions about the development of a field. **Figure A-6** is an example of how several formation evaluation techniques are plotted in a single graphic presentation.

<u>**Mud Logging**</u>

While the well is being drilled, the drilling mud is evaluated for the presence of hydrocarbons. This is commonly done through a technique called mud logging. Drilling will liberate even small amounts of hydrocarbons from sedimentary rock. As the mud comes up out of the hole, instruments are used to monitor the presence of gas or oil that may be present as the bit penetrates the subsurface. Evidence for the presence of hydrocarbons is called a show, which must be evaluated to determine whether a show is indicative of commercial hydrocarbon

Figure **A-6** Wireline Log (left) Combined With Other Formation Evaluation Data reservoirs. Mud logging evidence of hydrocarbons often is not definitive of a commercial show, but mud logs, in combination with other formation evaluation tools, are an important part of the overall evaluation of the hydrocarbon potential. The mud logging equipment also monitors for the presence of hydrogen sulfide (H_2S), a deadly gas.

The mud log, in addition to recording the presence of hydrocarbons and other gases, also is used to record and describe the rocks that are encountered in the well. The equipment used to remove rock cuttings from the mud also is used to obtain chips for sample description. Samples of rock cuttings from downhole are taken at prescribed intervals. The depths from which the samples came is determined by knowing the lag time it takes for the cuttings to reach the surface. The mud log can summarize all the formation evaluation activities for the well and the mud log format is a strip-chart display of the intervals logged depicting shows, formation tops, lithologic descriptions, wireline log data, gas readings, drilling data, and core and test intervals and descriptions.

Wireline Well Logs

Wireline well logs (or geophysical well logs) are basic to formation evaluation. Open-hole (hole without casing) wireline well logs can be run before intermediate casing strings are set and when the well reaches total depth. Wireline well logs also may be run in cased-holes. Wireline logs use a variety of techniques to provide indirect measurements of rock properties and are used to precisely determine the elevation and thickness of individual rock units or potential producing zones. In general, wireline logs require the application of electrical, sonic, mechanical, or radioactive energy to the rocks in order to obtain measurements that can be related to rock properties such as porosity, permeability, and fluid ratios (Berg, 1986). Only a few types of wireline logs do not require the application of energy to the rocks to make measurements. For example, the gamma ray log measures the natural gamma ray radiation from the rocks and is used to determine lithology (shale versus non-shale). Wireline logs are created by lowering instruments (the logging tool) into the well. The instruments are suspended by a cable that not only supports the logging tools, but relays measurement data by electrical signals to the surface. The general procedure is to lower the logging tool to the bottom of the hole and take measurements while hoisting the tools back to the surface. Several types of logs can be run in combination. The data from the tools are digitally processed at the surface and the information is summarized on what are generally described as well logs (**Figure A-6**).

Formation Testing

Zones with porosity can be determined while drilling when the rate of penetration begins to increase. When combined with evidence of the presence of hydrocarbons in the increased penetration interval, the well can be temporarily completed. The temporary completion of the well is called a drill stem test (DST) and can be useful in determining if hydrocarbons are present in commercial quantities. In a DST, a tool is placed on the end of the drill string and run back into the hole opposite the prospective interval. A device called a packer is placed above the tool in the BHA and is inflated against the walls of the hole to seal the zone from the mud column above. The tool is opened and fluids from the formation are allowed to enter the drill stem. A typical DST will include several periods of flow and shut-in. Pressure recorders are present in the test tool as well as sample chambers. When the test is over, the packer is released and the tool is brought to the surface and the pressure recorder charts are analyzed and the potential productivity of the zone can be estimated. Sample chambers in the test tool are designed to capture formation fluids and may contain oil, water, or gas. In addition, fluids produced into the drill stem may include varying amounts of oil, gas, and water. A good test can recover hundreds or thousands of feet of oil in the drill pipe or enough gas to the surface to flare.

A variation of the DST is the repeat formation test tool that is run into the hole by use of a wireline. The tool is pressed up against the sides of the borehole in the interval of interest. One of the major advantages of the wireline tester is the ability to obtain real-time pressure readings and the ability to test multiple zones. The wireline formation tester also has sample chambers for the recovery of formation fluids.

Coring

Coring is a method of formation evaluation whereby a whole sample of the subsurface rock is brought to the surface. Cores are obtained by placing a special bit and core barrel at the end of the drill string. Instead of drilling the rock into small pieces, a cylindrical core is cut. Core barrels are commonly 30 to 60 feet in length. When the core is brought to the surface, it is described by a geologist and then packaged and sent to a laboratory where it can be analyzed for certain properties such as porosity (space in the rock that is filled by fluids), permeability (the ability of the rock to transmit fluids), and the ratio of fluids present in the pores of the rock (oil, gas, and water) (Berg, 1986).

Another method used to obtain whole rock samples is the side-wall core sampler. Side-wall cores are obtained using a wireline tool that shoots small core barrels into the side of the well bore. The barrels are secured to the wireline tool by cables and the core is retrieved by pulling on the tool.

Measurement While Drilling

MWD is a well logging technique developed in the last two decades that allows some of the same measurements that are done by wireline logs to be accomplished in real time while the well is being drilled. This technique allows certain types of information to be gained in case the hole is lost before the wireline logs are run, to monitor rock properties that can indicate the presence of abnormal pressure conditions before drilling into them. Data from the measurement sensors near the bit are transmitted through fluid pulses through the drilling mud. MWD also is critical to directional and horizontal drilling providing real-time measurements so that immediate adjustments can be made in hole attitude and direction.

A3.4.2 Coalbed Methane

A3.4.2.1 Drilling Procedures

Drilling for CBM is very similar to drilling for conventional oil and gas except that generally much smaller drilling rigs are used since, at present, CBM resources are at much shallower depths on average than oil and gas. In addition to the smaller drilling rigs, instead of drilling mud, air also can be used for the same purpose, to clean the bottom of the hole and to move rock cuttings to the surface. Often the holes are drilled with air to the top of the coal zones, then the system is changed over to mud (Logan, 1993).

A3.4.2.2 Casing and Cementing

Surface casing is also required to be set in CBM wells to protect potential aquifers. The depth of surface casing is determined by the regulatory agency and depends on the depth of water zones that need to be protected. Production casing can be set in either one of two ways: 1) the casing can be set below the coal zone and cemented in as completed for typical oil and gas wells, or 2) the casing can be set above the coal zone, which is called an open hole completion (Logan, 1993).

A3.4.2.3 Blowout Prevention

BOPs also are required for drilling CBM wells as required by Onshore Rule No. 2 (BLM, 1988).

A3.4.2.4 Formation Evaluation

Wireline well logs are common formation evaluation tools for CBM wells. The well logs provide information on depth, thickness, and total number of coal seams. In addition, other properties can be determined such as porosity, fractures, and the amount of ash (mineral material) in the coal (Sholes and Johnson, 1993).

An important aspect of formation evaluation of coals for methane production is to estimate the amount of gas that is potentially available to produce from the coal. The gas in coal is present through a process called sorption, whereby the gas is present on the surface of the coal in a compressed or liquid state. In order to produce the gas, it must be desorped from the coal. Desorption is accomplished by lowering the hydrostatic pressure on the coal by producing the water in the coal. In CBM formation evaluation, the amount of gas that can be desorped is critical in determining whether a well or number of wells will be economic. The amount of gas that can be produced can be estimated using direct or indirect methods (Yee and others, 1993). One direct method is to conduct tests on whole core or drill cuttings whereby the coal samples are put into a gas-tight chamber and the gas is allowed to evolve and is measured. Corrections are made for the potential lost gas that occurs when the cores are brought to surface and before they can be placed into the gas-tight containers. A variation on the foregoing technique is to obtain pressure cores, a method that seals the core under formation pressure. In the pressure core method, gas losses are minimized and a more accurate estimate of potential gas can be made (Yee and others, 1993). Indirect methods of desorption potential do not measure gas directly but rather measure the sorption capacity of the coal.

A4.0 FIELD DEVELOPMENT AND PRODUCTION

A4.1 Oil and Natural Gas

A4.1.1 Field Development

New field developments are analyzed under NEPA by means of an environmental assessment (EA) or environmental impact statement (EIS) after the second or third confirmation well is drilled. The operator should then have an idea of the extent of drilling and disturbance required to extract and produce the oil and gas, once the second or third well is drilled.

When an oil or gas discovery is made, a well spacing pattern must be established before development drilling begins. Well spacing is regulated by the WOGCC. Factors considered in the establishment of a spacing pattern include reservoir data from the discovery well including porosity, permeability, pressure, composition, and depth. Other information pertinent to determining spacing includes well production rate, relative amounts of gas and oil in the production stream, type, and the economic effect of the proposed spacing on recovery. Spacing for oil wells usually varies from 40 to 320 acres per well, but can be as dense as 10 to 20 acres per well.

Spacing for gas wells is generally from 160 to 640 acres per well, but spacings of 20 to 40 acres are possible. Spacing requirements can pose problems in selecting an environmentally sound surface location. Reservoir characteristics and the drive mechanism determine the most efficient spacing to achieve maximum production. If an operator determines that a different spacing is necessary to achieve maximum recovery, the state and federal agencies may grant exceptions to the spacing requirements. Exceptions also may be obtained if the terrain is unsuitable, provided no geologic or legal problems are encountered. The procedures for obtaining approval to drill and for the drilling of development wells are generally the same as those for wildcat (exploration) wells.

Many fields go through several development stages. A field may be considered fully developed and produce for several years and then new producing zones may be found. If commercial hydrocarbons are discovered in a new producing zone in an existing field, it is called a new pool discovery, as distinguished from a new field discovery. New pools can either be deeper or shallower that the existing producing zone. A new pool discovery may lead to the drilling of additional wells. Shallower pay might be exploited from existing wells or deeper zones may be accessed by deepening existing wells. Often it is found that an established spacing rule is not effectively draining the producing zone in the field because of factors, such as reservoir heterogeneity or non-continuity of the reservoir, that were not detected when the field was initially developed. If an operator can substantiate (through pressure testing, 3-D seismic surveys, or other evidence) that the initial spacing is not effectively draining the reservoir, the operator can petition the WOGCC for a new spacing.

As more wells are placed in production, roads are improved by regular maintenance, surfacing with gravel or scoria, and installing culverts. Mineral materials are usually purchased from local contractors and obtained from federal sources. Materials that are obtained from areas of federally owned minerals require a sales contract and are processed through the FO where the materials occur. A new stage of field development can lead to changes in locations of roads and facilities. All new construction, reconstruction, or alterations of existing facilities-including roads, dams, pits, flowlines, pipelines, tank batteries, or other production facilities must be approved by the BLM.

Production from multiple wells on one lease may be carried by flowlines to a central processing facility. Central processing and storage facilities can be used for multiple wells on the same contiguous lease or multiple wells in an established unit.

During the productive life of a field, problems may arise such as erosion, barren to sparsely vegetated areas, washouts of drainage crossings, plugging of culverts, deterioration of cattleguards, accumulation of derelict equipment, construction of unnecessary roads, unauthorized off-road cross-country travel, and improperly placed or out of service pipelines. Rehabilitation plans are prepared by either industry or BLM to correct these problems and to return the field surface area to its original productivity. Corrective action will be taken as problems arise. This ongoing restoration will allow total rehabilitation to be more quickly accomplished at the end of a field's productive life (BLM and USFS, 1989).

A4.1.2 Unitization

In areas of federally owned minerals, an exploratory unit can be formed before a wildcat exploratory well is drilled. Federal units were authorized by The Mineral Leasing Act of 1920 and Title 43 CFR Subpart 3186 (2002) sets forth a model onshore unit agreement for unproven areas. The boundary of the unit is based on geologic data. A unit operator is determined by agreement of the leaseholders (often the leaseholder with the largest leasehold position is designated operator of the unit). An advantage of a unit is that, if oil and gas are discovered, unit development can proceed in a deliberate and efficient manner to minimize waste of hydrocarbon resources. For instance, pressure maintenance wells can be installed prior to full-scale production, which, in some types of reservoirs, may significantly increase recovery factors.

Another advantage of unitization is that surface use is minimized because all wells are operated as though on a single lease. Duplication of field processing facilities is minimized because development and operations are planned and conducted by a single operator. Often powerlines can be distributed throughout the unit and well pump can be powered by electric motors.

Unitization may enable the field to be developed with fewer wells minimizing surface disturbance through fewer locations and less road mileage.

It is the general intent of unitization to pool or unitize the interests in an entire structure or area in order to provide for adequate control of operations so that development and production can proceed in the most efficient and economical manner and with minimized environmental impact. Accordingly, each proposal to unitize federally supervised leases must be evaluated upon its specific merits. The unit agreement provides for the exploration, development, and production by a single operator. In effect, the unit functions as one large lease.

The purpose of a unit is to conserve the natural resources of the pool, field, or area involved. The early consolidation of separate exploration and development efforts through unitization of separate leasehold interests eliminates the need (with respect to drainage) to drill protective wells along common boundaries between leases and serves to maximize benefits through a consistent exploration and development program.

A4.1.3 Production Practices

A4.1.3.1 Well Completion

After the production string is cemented into place, the drilling rig is moved off and a smaller rig (called a workover rig or pulling unit) is set in place over the hole. After time is given for the cement to cure, an interval coinciding with the producing zone is perforated. Perforating is accomplished through the use of bullet-like projectiles or, more commonly, with shaped-charges. Perforating cuts holes through the casing and to several feet into the formation. After the zone is perforated, the holes may be cleaned out using a fluid flush treatment, commonly acid. The acid helps remove invaded drilling mud and pulverized rock particles created by perforating.

Generally, most hydrocarbon wells require stimulation beyond cleanup of the perforations. Additional stimulation is accomplished through hydraulic fracturing of the producing zone. Hydraulic fracturing is accomplished by pumping large volumes of liquid (usually water) and proppant material under pressure into the formation. The fluids from the fracturing are recovered (swabbed back), and the proppant is left in the fractures. The proppant may be composed of silica sand obtained from natural sandstone formations or may be derived from artificial materials such as ceramic. The proppant is used to keep the fractures open once the pumping pressure is stopped in the fracturing process.

After stimulation is complete, production tubing is run into the well and may be anchored to the inside of the production string by the use of a production packer. The packer not only anchors the tubing but also prevents fluid from entering the annular space between the casing and tubing. At the surface, equipment is installed on the tubing to control pressure and the flow of the production stream to processing equipment.

A4.1.3.2 Well Production

Gas, oil, and water are being produced in the RMPPA by means of natural flow and artificial lift (pumping or gas lift). The following describes typical production practices at gas and oil wells.

Gas Wells

Production and processing equipment at a typical gas well location might consist of a wellhead (called christmas tree), a production separator, a dehydrator, and tanks (**Figure A-7**). The christmas tree has valves used to control the flow of gas and liquids from the well (**Figure A-8**). As gas comes to the surface, it is diverted to processing equipment on the location. The gas must be separated from liquids in the production stream that may consist of water, gas condensates, or light crude oil. The production stream is placed into a production separator where the majority of the water and liquid hydrocarbons are removed from the gas. The gas is then fed into a device called a dehydrator to remove water that may remain in the gas. There are several processes used for dehydration, one of the most common being the use of glycol. The gas then goes through a metering facility and then into a sales or gathering pipeline. The hydrocarbon liquids are recovered and placed into tanks. Often 400-barrel tanks (1 barrel equals 42 gallons) are used, but commonly gas wells make so little hydrocarbon condensate (drip) that it can be placed in smaller tanks. Condensate or crude oil is trucked from the well for sale or placed into a pipeline. Produced water is either placed into a tank (often a below-grade steel tank called a tinhorn) or, if permitted, into a shallow evaporation pit. Unlined evaporation pits can be used if water production is less than 5 barrels of water per day and if there are no potential impacts to shallow groundwater (WOGCC, 2001).

Methanol is commonly used to keep production and surface lines from freezing because of pressure drops that occur when gas comes to the surface and result in line freeze ups, even in summer. The methanol is injected into the wellhead. Sometimes a device called an intermitter is used to either shut-in the well to build up pressure or to open up the well (blow down) if it is being loaded with fluid. If too much fluid is coming in to the well bore, gas may cease to flow, a condition called loading up. Loading up may cause loss of productivity or permanent damage to the well, which may result in the loss of flow.

After dehydration, the gas is moved into field pipeline gathering systems. In order to move the gas through the pipelines, compression equipment is used. Field compression units are small and

Figure **A-7** Typical Gas Well Production Facility

Figure **A-8** Well Heads or (Christmas Trees): Gas Well (Left), Pumping Oil Well (Right) mobile and are often skid-mounted for portability. Field units are sized for the amount of gas that needs to be moved and are often temporary because of the changing compression needs in a field, especially as it undergoes initial development. From the field gathering lines, the gas is fed into larger transportation lines, often at compressor stations along the transportation line. Before the gas is put into the transportation lines, it may undergo further processing to remove hydrocarbon condensates and water to ensure the gas meets stringent transportation pipeline specifications.

Commonly, natural gas needs more than simple wellsite processing. Large scale gas processing is conducted at facilities called gas plants. Gas plants typically handle large volumes of gas from multiple wells and can be designed to handle a variety of product and impurity separation processes. Sometimes the gas contains heavier hydrocarbon compounds known as natural gas liquids (NGLs). These NGLs, in addition to being valuable products, also need to be processed out of the methane stream to meet the transportation pipeline specifications. In addition to NGLs, natural gas also may contain impurities or large amounts of non-flammable gases that need to be removed from the methane. A major impurity is H_2S that, for safety and environmental concerns, needs to be removed from the gas. Carbon dioxide (CO_2) is an important non-flammable gas that, if found in large enough quantities, may be commercially viable.

Oil Wells

Typical oil well locations consist of a wellhead, pumping equipment, phase separation equipment, and storage tanks. Multiple wells on the same lease or unit may produce into central processing facilities, whereas more remote wells or a single well on a lease will have all the necessary processing and storage equipment.

Oil wells can be completed as flowing wells or pumping wells. Flowing wells have sufficient formation pressure to raise the oil to the surface. If formation energy is insufficient to raise the fluids to the surface, the oil is pumped. The most common types of pumps are called rod pumps **(Figure A-9)** (Boyd, 1971). These pumps are placed next to the perforations and are actuated by surface beam pumping units at the surface (or pump jacks). The downhole pumps are connected to the pump jacks by a string of steel rods called sucker rods. In both types of pumps, movement of the sucker rods moves traveling valves that either open or close and cause the fluid to move in to the well casing and up the tubing. Pump jacks come in a variety of sizes depending on the depth and the total amount of fluid anticipated to be pumped, the larger ones reaching a height of 30 to 40 feet. Pump jacks are powered by internal combustion engines or electric motors. Fuel for the internal combustion engines may be casinghead gas (gas produced with the oil) or propane.

Another pumping method involves the use of electrically powered submersible pumps that are suspended below the fluid level in the well. The fluids are pulled into the tubing and pumped to the

Figure **A-9** Pump Jack and Downhole Pump surface. Submersible pumps are used when large volumes of fluid have to be produced such as wells where there are large amounts of water produced with the oil. The submersible pumps can pump higher volumes of fluid and enable wells with high water cuts to remain economically viable.

Another method of artificial lift is called gas lift, whereby natural gas is pumped into a well to provide the energy to lift the fluids to the surface (Boyd, 1971).

Fluids produced from an oil well are generally composed of three phases: oil, water, and gas. When the fluids reach the surface, they must be separated. This is accomplished through the use of separation equipment that is appropriate for the proportions of fluid that are being produced (**Figure A-10**). If there are large amounts of water, the water is separated by a vessel called a free water knockout (FWKO). Free water is water that is easily gravity-separated from the oil. The remaining fluid is fed into heater-treaters, which separate not only the gas and the oil, but also break apart water-in-oil emulsions that may occur during the production process. Dilute brines can form emulsions that are difficult to separate into distinct oil-water phases (Manning and Thompson, 1995). Produced water that is separated from the oil is routed into tanks for disposal. FWKOs and heater-treaters burn gas to facilitate separation of the fluids. The gas may be used to heat the fluids and is either provided from commercial propane or casinghead gas. Emulsions are usually treated with chemicals for severe or difficult emulsion problems.

The casinghead gas, depending on the quantities produced, can be used on the lease, recovered and placed into pipelines for sale, or vented. The WOGCC prohibits the flaring or venting of natural gas except during testing of a new well or when the amount of gas produced with the oil is so small that pipeline construction is not practical. An operator that intends to vent gas must submit an air quality permit application to the Wyoming Department of Environmental Quality. Normally gas produced in such circumstances will be granted a waiver of permit because the amounts are small. Flaring of gas would also require the submission of an air quality permit application. If an oil well produces sufficient quantities of gas, provisions for recovering the gas must be made before oil production can commence. If casinghead gas is placed in gathering or sales pipelines, it must be dehydrated and metered as at a gas well.

After the separation process, oil and water are stored in tanks either at the location or at central processing facilities. The capacities of the tanks are generally from 400 to 600 barrels and any given tank battery will have varying numbers of tanks depending upon the productive capacity of the well. Tanks and separation vessels are placed within earthen berms or other containment structures in order to contain spilled fluids in case of an upset condition or rupture of a tank or vessel. Production equipment are required to be painted in colors that will blend into the surrounding environment. Popular colors are brown and green. Some or all of the facility must be fenced. If production pits are present, the pits must be fenced and netted to protect livestock and wildlife.

Figure **A-10** Oil Well Process Equipment

Two main methods of oil measurement in the area are utilized. These are the lease automatic custody transfer meters for pipeline transport and tank gauging by company personnel. Measurement is required by 43 CFR 3162.7-2 (2002) and Onshore Order No. 4 (BLM, 1989) to ensure proper and full payment of federal royalty.

Production Waste

Water is produced in large quantities and is the largest volume of waste generated in oil and gas production. Disposal of water produced on leases managed by the BLM is regulated by the Onshore Oil and Gas Order No. 7 (BLM, 1993). Although produced water can have less than 5,000 parts per million (ppm) TDS and is often usable for livestock and irrigation, usually the water cannot be used for beneficial purposes and must be disposed in a manner protective of the environment. The water can be handled in several ways. One of the most common methods is to re-inject the water into the producing formation to maintain pressure in the reservoir as part of a secondary recovery waterflood. Another method involves the injection of the fluid into brine disposal wells, either owned by the operator or by third parties. A new method has been developed that injects water into another zone in the same well and much of the water never reaches the surface. Subsurface water disposal methods are permitted by the WOGCC under the underground injection control program. Downhole injection in the same well is still a relatively new and experimental method for disposing of water and still being evaluated by the U.S. Environmental Protection Agency (USEPA).

As mentioned above, water can be placed into evaporation pits if water volumes are small. Pits may be lined or unlined depending upon the discretion of the permitting authority. Water can also be hauled from the location by third-party commercial contractors and disposed of in large lined evaporation pits. Such commercial facilities are licensed and regulated by the WOGCC and must conform to construction, operating, and closure standards specified by rule (WOGCC, 2001).

Much of the waste generated by production operations is exempt from regulation as hazardous waste. However, the waste must be disposed of in a manner acceptable by law. Waste that is exempted is waste that is intrinsic to the production process (USEPA, 1988 and 1993). Examples of exempt waste are formation water, hydrocarbon impacted soil, drilling mud, and drill cuttings. These wastes can be dealt with in a variety of ways under existing regulations, but must be handled in a manner protective of public health and the environment. Other wastes, not classified as exempt, must be disposed of properly according to regulation.

Production Problems and Workovers

Weather extremes pose problems for operators by causing roads to become impassable, equipment to malfunction, and freeze-up of flowlines, separators, and tanks. Other problems that operators face are H_2S, CO_2, paraffin, corrosion, electrolysis, and broken flowlines.

During the life of a producing well, it may be necessary to take the well off-line and service the well or conduct a workover. Often workovers are done for routine maintenance (replace pumps, clean out perforations) or may be conducted because of severe operating malfunctions (e.g., rod separation, casing leaks, cement breakdowns). Workovers are conducted with small rigs called workover rigs or pulling units. Pulling units are typically self-propelled rigs that have a mast that is erected over the hole. Rods and tubing are pulled out of hole and stacked vertically within the mast.

A4.1.4 Secondary and Enhanced Recovery

The initial stages of production, whether by natural flow or by pumping, is referred to as primary recovery. As the reservoir is produced over time, the energy needed to move fluid from the formation to the wellbore is depleted. Depending on economics, additional recovery methods may be used. These methods are referred to as secondary recovery.

There are two basic secondary recovery methods in use, water flooding and displacement by gas. The most important secondary recovery method in use is water flooding. Water flooding is the process of injecting large volumes of water into oil reservoirs where primary reserves are being depleted to enhance and accelerate recovery.

The process of injecting gas into the producing zone is another, but less common, secondary recovery technique. Historically, produced gas was often flared (burned) at the point of production because of poor market conditions or absence of pipelines to transport the gas. Later, it was recognized that the energy could be conserved and the recovery of oil increased if the produced gas was re-injected into the producing zone. This increased production was achieved by: 1) maintaining reservoir pressure by injecting the gas into the existing gas cap; and 2) by injecting the gas directly into the oil saturated zone, creating an immiscible or miscible gas drive, which displaced the oil.

Beyond secondary recovery, enhanced recovery is used to describe recovery processes other than the more traditional secondary recovery procedures. These enhanced recovery methods include thermal, chemical, and miscible (mixable) CO_2 drives. When enhanced recovery methods are used after secondary recovery methods have reached viable limits, they are often referred to as tertiary recovery.

Some reservoirs contain large quantities of heavy oil that cannot be produced using primary or secondary methods. In thermal drive processes, heat is introduced from the surface or developed in place in the subsurface reservoir. In the thermal drive process, hot water or steam is injected. In the in-situ process, spontaneous or induced ignition of in-place hydrocarbons are created in the presence of injected air to develop an in-situ fire front. Raising the temperature of heavy oil causes it to become less viscous and more mobile so that it may be produced through gravity forces or preferably by displacement.

There are several chemical drive techniques currently in use, including: 1) polymer flooding, 2) caustic flooding, and 3) surfactant-polymer injection. These methods attempt to change reservoir conditions to allow additional oil to be recovered.

A4.2 Coalbed Methane

A4.2.1 Field Development

Because CBM has some inherent differences from oil and non-coalbed gas development, it occurs in a different way. The economic viability of any particular project will not be known until several wells have been drilled and completed and the coal has been depressured enough to make an estimate of economic viability. When federal managed lands are involved, new CBM developments are analyzed under the NEPA by means of an EA. In initial CBM development, the operator may drill 2 or 3 wells from which to obtain core samples to determine methane desorption potential, total aggregate thickness of coal seams, and other data from which to get an estimate of future production.

If it is determined that there is commercial potential for CBM, the typical route to development is to begin to produce the wells in order to draw off the water to see if the coal seams are able to produce at preliminary estimated rates. Often a pilot project will be proposed in which a few wells are drilled at an adequate spacing to test the efficacy of pumping water. Usually 8 to 10 wells are drilled and pumped to the point until significant gas is produced. If the production proves to be economical, then the operator will propose to drill a number of wells that will most efficiently drain the gas from the coal. Spacing in CBM projects can vary from one well per 320 acres to one well per 20 or 10 acres. The spacing depends on the amount of gas that could be recovered, depth, permeability, porosity, and net coal thickness (Kruuskra and Boyer, 1993).

When a CBM project is deemed economical to warrant full-scale production, often many wells are proposed to be drilled. The number of wells is dependent several variables and the number of proposed wells can exceed 100. The large number wells may cause an EIS to be conducted. As in oil and natural gas developments, a CBM development will require drilling pads, roads, pipelines, compressors, and other infrastructure. On federally managed lands, the construction and installation of the production infrastructure must be approved by the BLM.

A4.2.2 Unitization

The establishment an exploration unit is advantageous for CBM production so that the development can be conducted in an orderly manner by one operator.

A4.2.3 Production Practices

A4.2.3.1 Well Completion

CBM wells can either be open hole completions or cased hole completions. In open hole completions, the production casing is set above the target coal zones. In cased hole completions, production casing is placed through the coal zones and cemented in. Often there are several coal zones that are produced in one well, rather a single coal zone. One common method of openhole completion involves creating a cavity in the coal (Palmer and others, 1993). The cavity that is created can be 4 to 5 feet across (nominal borehole size: 7 7/8 inches) by repeated injection of compressed air into the coal zones. The cavitation process can enhance permeability without the use of hydraulic fracturing. In the traditional cased hole method, the coals are hydraulically fractured to enhance permeability. Certain types of hydraulic fracturing can damage coal zones so that, over the years, treatments have been designed especially for CBM wells.

A4.2.3.2 Production Practices

A CBM production unit consists of wells, gas and water gathering lines, separators, compressors, gas dehydrators, measurement systems, water treatment facilities, roads, and utilities (Schraufnagel, 1993).

In the production process, typically large amounts of water have to initially be drawn out of the coal seam in order to desorb the gas. **Figure A-11** shows typical water-gas production curves for a CBM well. Several methods of artificial lift can be used to move the water to the surface. Pumping methods include rod pumps, submersible pumps, gas lift, and progressing cavity pumps (Schraufnagel, 1993). Once the water and gas are lifted to surface, the fluids are put through separators. Because of the quantities of water typically produced, the production stream is put through FWKO to remove most of water. At this stage the gas may still be saturated with water and is put through a two-phase separator. The gas is then routed through a metering system and placed into a gathering pipeline system. The gas may have to go through another dehydration step prior to putting it into a sales or transportation line.

Figure **A-11** Typical Production Curves for a CBM Well

The produced water also is routed into a gathering pipeline system for disposal. There are two major disposal options for the water: surface discharge and subsurface injection (Schraufnagel, 1993). All water disposal methods must be approved by appropriate regulatory authorities. Surface disposal is allowed only if the water meets certain permit-required limitations on quality and constituents. Often the water is usable for livestock watering and irrigation. In those cases, it can be discharged to surface drainages or, more commonly, into ponds. If the water, as pumped from the subsurface, does not meet discharge limits, it can be treated and then discharged to the surface. However, pretreatment options such as reverse osmosis are relatively expensive compared to other disposal options, may not be effective for large volumes of water, and must be properly designed to ensure that the system operates effectively. Evaporation ponds can be used for disposal but are not effective for handling large amounts of water over long periods of time, especially in Wyoming. Although Wyoming has a semi-arid climate, ideal conditions for evaporation occur only within a period of a few months of high temperatures. For most of the year, conditions are not conducive to effective evaporation of large amounts of water.

Subsurface disposal can be accomplished through deep well injection. The water can also be re-injected into an aquifer only if the water meets water quality requirements. To accomplish injection, the water may have to undergo limited pretreatment, such as solids settling and filtration (Schraufnagel, 1993).

As in oil and non-CBM gas wells, workover operations are conducted for routine maintenance, failure of downhole equipment (rods or pumps), or re-stimulation (Schraufnagel, 1993).

A5.0 ABANDONMENT AND RECLAMATION

A5.1 Plugging and Abandonment of Wells

The purpose of plugging and abandoning a well is to prevent fluid migration between zones, to protect minerals from damage, and to restore the surface area. Each well has to be handled individually due to a combination of factors including geology, well design limitations, and specific rehabilitation concerns. Therefore, only minimum requirements can be established then modified for the individual well. Oil, non-CBM gas, and CBM wells must be plugged according to the same protection requirements.

The first step in the plugging process is the filing of the NOI to Abandon to the BLM or the State. This notice will be reviewed and approved by the controlling agency prior to plugging whether the well is former producing well or if the well was an exploratory well. If the well is an exploratory well, verbal plugging instructions can be given for plugging current drilling operations, but a Sundry Notice of Abandonment must be filed after the work is completed. If usable fresh water was encountered while the well was being drilled, the surface owner may be allowed, if interested, to assume ownership of the well and convert it to a water well.

The operator's plan for plugging the hole is reviewed by the SMA. The minimum requirements are stated in Onshore Order No. 2 (BLM, 1988). There are different requirements for open holes (wells without production casing) than for cased holes. In open holes, cement plugs must extend at least 50 feet above and below zones with fluid that has the potential to migrate, zones of lost circulation (this type of zone may require an alternate method to isolate), and zones of potentially valuable minerals. Thick zones may be isolated using 100-foot plugs across the top and bottom of the zone. In the absence of productive zones and minerals, long sections of open hole may be plugged with 150-foot plugs placed every 3,000 feet.

In cased holes, cement plugs must be placed opposite perforations and extending 50 feet above and below except where limited by the plug back total depth of the well (**Figure A-12**). The cement plugs could be replaced with a bridge plug if the bridge plug is set within 50 to 100 feet above the open perforations, and only if the perforations are isolated from any open hole below. The bridge plug must be capped with 50 feet of cement. If the cement cap is placed using a dump bailer, a minimum of 35 feet of cement is sufficient. A device called a dump bailer is a wireline apparatus useful for cement placement because tubing does not have to be run and cement contamination is minimized. This method employs the use of a container of cement, which is lowered into the hole and dumped.

Figure **A-12** Completed and Abandoned Well Bore Diagrams

In the event that the casing has been cut and recovered, a plug is to be placed 50 feet above and below the cut off point. No annular space can be open to the surface from the drilled hole below. At a minimum, the top 50 feet of annular space must be plugged with cement.

If the integrity of a plug is questionable or the position extremely vital to protect certain zones, it can be tested with pressure or by tagging the plug with the drill string. Tagging the plug means running pipe into the hole until the plug is encountered and placing a certain amount of weight on the plug to verify its placement and competency. The top surface plug must be a minimum of 100 feet and no less than 25 sacks of cement. The interval between plugs must be filled with drilling mud of a minimum weight of 9 pounds per gallon.

After the casing has been cut off below the ground level, any void in the top of the casing must be filled. If a metal plate is welded over the top of the casing, weep holes should be drilled in the plate to vent the annular space.

A permanent abandonment marker is required on all wells unless otherwise requested by the SMA. This marker pipe is usually at least 4 inches in diameter, 10 feet long, 4 feet aboveground, and embedded in cement. The well identity and location must be permanently inscribed on the side of the pipe or on a cap placed on top of the pipe.

The SMA is responsible for establishing and approving methods for surface rehabilitation and determining when the rehabilitation has been satisfactorily accomplished. At this point, a Subsequent Report of Abandonment can be approved.

A5.2 Reclamation

An exploratory drilling location or an abandoned producing well location must be reclaimed according to requirements set forth by the BLM (BLM and USFS, 1989), the WOGCC (2001), and stipulations in the original lease agreement. Once the drilling or production equipment is removed, the location and access road must be graded to original contours, pits properly closed and backfilled, and then the disturbed areas are revegetated with appropriate seed mixtures to enhance the reclamation of the area.

A6.0 NEW TECHNOLOGIES

Drilling and production methods are constantly being improved to reduce costs and to more effectively produce oil and gas. Often new technologies create benefits for the environment. The following is a discussion of a number of new technologies that are being used or could be used in the RMPPA to improve production practices or help limit the impact to the environment.

Innovative drilling and completion techniques have enabled the industry to drill deeper (with fewer dry holes) and to recover more reserves per well. Smaller accumulations once thought to be uneconomic can now be produced. Nationally, increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy [USDOE], 1999). These efficiencies can also be applied to southwest Wyoming.

Advances in technology have boosted exploration efficiency and new advances will continue this trend. Significant progress that has and will continue to occur is expected in the following:

- computer power, speed, and accuracy;
- remote sensing and image-processing technology;
- developments in global positioning systems;
- advances in geographical information systems;
- 3-dimensional and 4-dimensional time-lapse imaging technology that permits better interpretation of subsurface traps and characterization of reservoir fluid, improved borehole logging tools that enhance our understanding of specific basins, plays, and reservoirs; and
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions.

These new technologies will allow companies to target higher-quality prospects and improve well placement and success rates. As a result, fewer drilled wells are needed to find a new trap and production per well is increased (USDOE, 1999). With fewer wells drilled, surface disturbance and volumes of waste, such as drill cuttings and drilling fluids, is reduced. An added benefit of improved remote sensing technology is the ability to identify hydrocarbon seeps.

Technology improvements have cut the average cost of finding oil and gas reserves in the U.S. The USDOE (1999) estimated finding costs were approximately $12 to $16 per barrel of oil equivalent in the 1970s. Currently, the estimated finding costs are $4 to $8 per barrel.

A6.1 Drilling and Completion

Advanced Resources International (2001) used industry guidance to determine an average time required to drill and complete a well for certain depth ranges. They predicted an average time of 40 days to drill and complete a well of less than 10,000 feet, 65 days for wells between 10,000 and 14,000 feet, and 190 days for wells greater than 14,000 feet.

Drilling improvements have occurred in new rotary rig types, coiled tubing, drilling fluids, and wellbore condition monitoring during the drilling operation. Technology is allowing directional and horizontal drilling use in many applications. New bit types have boosted drilling productivity and efficiency. New casing designs have reduced the number of casing strings required. Environmental benefits of drilling and completion technology advances include:

- smaller footprints (less surface disturbance);
- reduced noise and visual impact;
- less frequent maintenance and workovers with less associated waste;
- reduced fuel use and associated emissions;
- enhanced well control for greater worker safety and protection of groundwater;
- less time on site with fewer associated environmental impacts;
- lower toxicity of discharges; and
- better protection of sensitive environments and habitat.

A6.1.1 Horizontal and Directional Drilling

Oil and gas wells in the RMPPA traditionally have been drilled vertically, at depths ranging from a few hundred feet in the La Barge area to 19,000 feet in the Wagon Wheel No. 1 gas well on the Pinedale Anticline. Depending on subsurface geology, technologic advances now allow wells to deviate from a few degrees from vertical to completely horizontal. Directional and horizontal drilling enable producers to reach reservoirs that are not located directly beneath the drilling rig. The capability to directionally drill has been useful in avoiding sensitive surface features in parts of the resource management plan planning area. Drilling and completing costs can be considerably higher for directional wells than for conventional vertical wells. Because of this, the need for directional wells must be evaluated in regard to the increased costs. It will not be economical in all cases to drill a directional well in lieu of conventional vertical well.

The industry has drilled 281 known directional wells in the RMPPA (IHS Energy Group, 2002). Exxon/Mobil Production Company, EOG Resources, Inc. and Chevron/Texaco have drilled most of the directional wells (227 wells) in the La Barge area. A few oil and injection wells have been directionally drilled but the majority of the directional wells have been drilled as Cretaceous-aged gas producers. In recent years, 10 to more than 20 directional wells have been drilled each year.

BP America Production Company, Forest Oil Corporation, and McMurry Oil Company have drilled 19 directional wells in the Jonah Field. The first directional well was drilled in 1998 and all were drilled as gas tests of the Lance Formation or Mesaverde Group. Anschutz Exploration Corporation, Wexpro Company, Ultra Resources, Inc., McMurry Energy Company, Questar Exploration and Production Company Oil, Petrogulf Corporation, ST Oil Company, and Yates Petroleum Corporation have drilled 35 wells along the Pinedale Anticline. The first was drilled in 1999 and all were drilled as gas tests of the Lance Formation or Mesaverde Group. Most of the directional wells drilled in the Jonah Field and on the Pinedale Anticline were located to avoid sensitive surface features identified in recent EISs.

Horizontal drilling targets can be hydrocarbons in thin, tight reservoirs, or targets that allow a wellbore to intersect more reservoir rock to increase hydrocarbon recovery. The benefits from increased production can, in some cases, outweigh the added cost of drilling these wells. Five horizontal wells have been drilled in the RMPPA (IHS Energy Group, 2002). In 1995, Mobil Oil Corporation drilled three productive Frontier Formation gas wells in the 6,000- to 7,000-foot depth range within the Tip Top Unit. In 1990, Texaco Exploration and Production Company (now ChevronTexaco) drilled one shallow, horizontal (400-foot depth range) oil well in the La Barge Unit. In 2001, Devon SFS Operating, Inc., completed the fifth well as a 7,800-foot horizontal Lance Formation gas producer in the Jonah Field.

Recent advances in directional drilling have encouraged multilateral drilling and completion, enabling multiple offshoots from a single wellbore to radiate in different directions or contact resources at different depths. Multilateral drilling can increase well productivity and enlarge recoverable reserves, even in aging fields. Environmental benefits of horizontal and directional drilling include:

- fewer wells and surface disturbance;
- lower waste volume; and
- protection of sensitive environments.

Chevron/Texaco is the only company that has drilled a multilateral oil well in the RMPPA. In 1990, they drilled three Almy Formation offshoots from one wellbore in the 400 to 500-foot depth range in the La Barge Unit.

A6.1.2 Slimhole Drilling and Coiled Tubing

Slimhole drilling is a technique used to tap into reserves in mature fields but has not yet been used much in southwestern Wyoming. It has the potential to improve efficiency and reduce costs of both exploration and production drilling. Coiled tubing, used effectively for drilling in reentry, underbalanced, and highly deviated wells, is often used in slimhole drilling. The USDOE (1999) reported that a conventional 10,000-foot well in southwestern Wyoming costing $700,000 could be drilled for $200,000 by using slimhole and coiled tubing. It is expected that slimhole drilling and coil tubing technologies will be used more often in the future. The USDOE (1999) has identified the environmental benefits of using these techniques, which include the following:

- lower waste volumes;
- smaller surface disturbance areas;
- reduced noise and visual impacts;
- reduced fuel use and emissions; and
- protection of sensitive environments.

A6.1.3 Light Modular Drilling Rigs

New light modular drilling rigs currently in production can be more easily used in remote areas and are quickly disassembled and removed. Its components are made with lighter and stronger materials and its modular nature reduces surface disturbance impacts. Also, these rigs reduce fuel use and emissions.

A6.1.4 Pneumatic Drilling

Pneumatic drilling is a technique in which boreholes are drilled using air or other gases rather than water or other drilling liquids. This type of drilling can be used in mature fields and formations with low downhole pressures and in fluid-sensitive formations. It is an important tool in drilling horizontal wells. This type of drilling significantly reduces waste, shortens drilling time, reduces surface disturbance, and decreases power consumption and emissions.

A6.1.5 Improved Drill Bits

Advances in materials technology and bit hydraulics have yielded tremendous improvement in drilling performance. Latest-generation polycrystalline diamond compact bits drill 150 to 200 percent faster than similar bits several years ago (USDOE, 1999). Environmental benefits include the following:

- lower waste volumes;
- reduced maintenance and workovers;
- reduced fuel use and emissions;
- enhanced well control;
- less time on site; and
- less noise.

Reducing the time a drilling rig spends on location reduces potential impacts on soils, groundwater, wildlife, and air quality.

A6.1.6 Improved Completion and Stimulation Technology

Hydraulic fracturing of reservoirs enhances well performance, can minimize the number of wells drilled, and allows the recovery of otherwise inaccessible resources. However, traditional fracturing techniques have caused damage to the formations and subsequent loss in expected productivity. The flow of hydrocarbons is restricted in some low-permeability and in unconventional resources (such as CBM), but can be stimulated by hydraulic fracturing to produce economic quantities of hydrocarbons. Fluids are initially pumped into the formation at high pressures that fracture the rock and followed by pumping a sand slurry into the fractures which props open the fractures, allowing hydrocarbons to enter the wellbore. Improvements such as CO_2-sand fracturing, new types of additives, and fracture mapping, promise more effective fractures and greater ultimate hydrocarbon recovery. Improvements in hydraulic fracturing technology have encouraged the extensive development of Jonah Field and along the Pinedale Anticline.

A6.2 Production

Once production commences, reservoir management is needed to ensure that as much hydrocarbon as possible is produced at the lowest possible cost, with minimal waste and environmental impact. In earlier days, recovery was only about 10 percent of the oil in a given field and sometimes the associated natural gas was vented or flared. Newer recovery techniques have allowed the production of up to 50 percent of the oil. Also, 75 percent or more of the natural gas in a typical reservoir is now recovered. Operators have taken significant steps in reducing production costs. The USDOE (1999) estimated that costs of production had decreased from a range of $9 to $15 per barrel of oil equivalent in the 1980s to an average of about $5 to $9 per barrel of oil equivalent in 1999.

Since 1990, most reserve additions in the United States, 89 percent of oil reserve additions and 92 percent of gas reserve additions, have come from finding new reserves in old fields (USDOE, 1999). Significant recent reserve additions in southwest Wyoming have come from old fields. The

USDOE (1999) also reports that about half of new reserve additions are from more intensive development within the limits of known reservoirs. They report that the other half of reserve additions has come from finding new reservoirs in old fields and extending field limits.

The following summarizes technologies and efficiencies that have helped reduce production costs and reduce impact on the environment.

A6.2.1 Acid Gas Removal and Recovery

Before natural gas can be transported safely, any H_2S or CO_2 must be removed. Special plants are needed to recover the unwanted gases and sweeten gas for sale. Improvements in the process have made it possible to produce sour natural gas resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and CO_2 for later sale or disposal.

A6.2.2 Artificial Lift Optimization

Improvements have enhanced production, lowered costs, and lowered power consumption, which reduce air emissions.

A6.2.3 Glycol Dehydration

Dehydration systems use glycol to remove water from wet natural gas before it enters a pipeline. During operation, these systems may vent methane and other volatile organic compounds (VOCs) which may include hazardous air pollutants (HAPs). Improvements to these systems have allowed increased gas recovery and have reduced emissions of methane, VOCs, and HAPs.

A6.2.4 Freeze-Thaw/Evaporation

A new freeze-thaw/evaporation process has been shown to be useful in separating out dissolved solids, metals, and chemicals that are contained in water produced from oil and gas wells. In 1998, this type of produced water facility was constructed for McMurray Oil Company (now Shell Oil) at Jonah Field (Petroleum Technology Transfer Council, 2002). Over the first winter season, 17,000 barrels of water with a TDS content of 22,800 milligrams per liter (mg/l) was treated. It yielded 9,500 barrels of treated water and 5,900 barrels of brine solution (1,900 barrels were lost to evaporation and sublimation). The treated water (1,200 mg/l dissolved solids) was suitable for reuse in near-surface wellbore applications. The brine (66,900 mg/l dissolved solids) was suitable for reuse in deep drilling operations. In each of the following years (2000 and 2001), progressively greater amounts of treated water have been produced at this facility.

A6.2.5 Leak Detection and Low-bleed Equipment

New technology is facilitating hydrocarbon leak detection and the replacement of equipment that bleeds significant gas, thus allowing increased worker safety, reduced methane emissions, and increased recovery and usage of valuable natural gas.

A6.2.6 Downhole Oil/Water Separation

Emerging technology to separate oil and water could cut produced water volumes by as much as 97 percent in applicable wells (USDOE, 1999). By separating the oil and water in the wellbore and injecting the water directly into a subsurface zone, only the oil needs to be brought to the surface. The new technology can minimize environmental risks associated with produced water handling, treatment, and disposal, and would reduce costs of lifting and disposing of produced water. In addition, surface disturbance could be reduced, oil production could be enhanced, and marginal or otherwise uneconomic wells could become producible.

A6.2.7 Vapor Recovery Units

Vapor recovery can reduce a lot of the fugitive hydrocarbon emissions that vaporize from crude oil storage tanks, mainly from tanks associated with high-pressure reservoirs, high vapor releases, and large operations. The emissions usually consist of 40 to 60 percent methane, along with other VOCs and HAPs (USDOE, 1999). Where useable, this technology can capture over 95 percent of these emissions.

A6.2.8 Site Restoration

Regulatory agencies are allowing flexible risk-based corrective action (RBCA) as a process to ensure quicker and more efficient clean up of sites impacted by oil or other regulated substances. RBCA allows cleanup standards for soil, groundwater, and surface water to be customized to the environmental setting of a particular site. Sites where drinking water or other sensitive receptors may be at risk may have more stringent cleanup standards than sites where there is a low probability of impact. This allows for a case-by-case approach to site remediation rather than one cleanup standard for all sites, regardless of threat.

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