PROPOSED CASPER
RESOURCE MANAGEMENT PLAN AND
FINAL ENVIRONMENTAL IMPACT STATEMENT

APPENDIX D

Oil and Gas Operations

Appendix D
Oil and Gas Operations

GEOPHYSICAL EXPLORATION

Oil and gas can be discovered by either direct or indirect exploration methods, such as geologic surface mapping, seeps, well data, and remote sensing data. In many cases, indirect-methods, such as seismic, gravity, and magnetic surveys, are required to delineate subsurface features that may contain oil and gas. Geophysical exploration provides information that increases the chances of drilling a discovery well, as well as information that may discourage drilling and the associated surface disturbance. More sophisticated geophysical techniques, such as a three-dimensional (3-D) seismic survey, is an intensive data acquisition and computer synthesis system used to analyze and three dimensionally depict subsurface geologic structures/stratigraphy. This technique is capable of locating and displaying unknown subsurface pools or pockets, which potentially could contain producible hydrocarbons. Data obtained through this 3-D geophysical data acquisition project should enable wells to be drilled with a much greater probability of locating producible hydrocarbons than is attainable via previous methods, such as two-dimensional (2-D) seismic data and wildcat wells. Thus, this should result in fewer "dry holes" in the future, minimizing the need for drilling and associated environmental disturbance.

Gravity Surveys

Gravitational prospecting detects micro-variations in gravitational attraction caused by the differences in the density of various types of rock. Gravity data are used to generate anomaly maps from which faults and general structural trends can be interpreted. These surveys generally are not considered definitive because of the many corrections required (e.g., terrain, elevation, latitude, etc.) and the poor resolution of complex subsurface 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. The gravimeter is transported either by backpack, helicopter, or off-road vehicle. The only surface disturbance associated with gravity prospecting is that which is caused by a vehicle, if used.

Magnetic Surveys

Magnetic prospecting most commonly is used for locating metallic ore bodies. It is used to a limited extent in oil and gas exploration. Magnetic surveys use an instrument called a magnetometer to detect small magnetic anomalies caused by mineral and lithologic variations in the Earth's crust. These surveys can detect trends in basement rock and the approximate depth to basement rocks, but, in general, they provide little specific data to aid in petroleum exploration. Many corrections are required to obtain reliable information. The generated maps lack high resolution and provide rudimentary views of subsurface geology. 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 nearly are identical to gravity surveys; surface disturbance is minimal to nonexistent.

Seismic Reflection Surveys

Seismic prospecting is the best and most popular indirect method used for locating subsurface structures and stratigraphy that may contain hydrocarbons. Seismic energy (shock waves) is induced into the earth using one of several methods, typically shot holes or vibrators. As these waves travel downward and outward, they encounter various rock strata, each having a different seismic velocity characteristic. As the wave energy encounters the interface between rock layers where the lower layer is of lower seismic velocity, some of the seismic energy is reflected upward. Sensing devices, commonly called geophones,

are placed on the surface to detect these reflections. The geophones are connected to a recording truck that stores the data. The time required for the shock waves to travel from the shot point down to a given reflector and back to the geophone is related to depth. This value is mapped to give an underground picture of the geologic structure.

Many methods exist today that an explorationist can use to induce the initial seismic energy into the earth. All methods require preliminary surveying and lying of geophones. The thumper and vibrator methods pound or vibrate the earth to create a shock wave. Usually, large trucks are used, each equipped with vibrator pads (about 4-foot square). The pads are lowered to the ground, and vibrators on all trucks are triggered electronically from the recording truck. Information is recorded, and then the trucks move forwards a short distance and the process is repeated. Less than 50 square feet of surface area is required to operate the equipment at each test site. The trucks are equipped with large flotation-type tires, which reduce the impact of driving over undisturbed terrain.

The drilling method uses truck-mounted and buggy-mounted drills that drill small-diameter holes to depths of 60 to 200 feet. Four to 16 holes are drilled per mile of line. Usually, a 30-pound charge of explosives is placed in the hole, covered, and then detonated. The detonated explosive sends a shock wave below the earth's surface that subsequently is reflected back to the surface from various subsurface rock layers. In rugged topography, a buggy-mounted drill is used or a portable drill is carried in by helicopter. Charges are placed in the hole as is done 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, about 3 feet above the ground. Usually, 10 charges in a line 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 subsurface geology. Subsequently, more extensive seismic lines are arranged to obtain the greatest amount of geologic information.

Seismic information can be obtained in 2-D or 3-D configurations. To obtain 3-D seismic information, the seismic sensors and energy source are located along lines in a grid pattern. This type of survey differs from the more common 2-D surveys because of the large volume of data and the intensive computerization of the data. The results are expensive to obtain but give a more detailed and informative subsurface picture. The orientation and arrangement of the components in 3-D seismic surveys are less tolerant of adjustments to the physical locations of the lines and geophones, but they are also more compact in the area they cover. Although alignment can be fairly critical, spacing of the lines often can be changed to increase the information collected. The depth of the desired geologic information will dictate the spacing of the grid lines, with smaller spacing detailing shallower formations. The 3-D surveys are very expensive and usually conducted after 2-D surveys or drilling has delineated a geologic prospect that will justify the extra cost. Extensive computer processing of the raw data is required to produce a useable seismic section from which geophysicists can interpret structural relationships to depths of 30,000 feet or more. The effective depth of investigation and resolution are determined to some degree according to the method used.

A typical drilling seismic operation can use 10 to 15 men operating five to seven trucks. Under normal conditions, 3 to 5 miles of line can be surveyed each day using the explosive method. The vehicles used for a drilling program include several heavy truck-mounted drill rigs, water trucks, a computer recording truck, and several light-weight pickup trucks for the surveyors, shot-hole crew, geophone crew permit person, and party chief. Helicopters are used to layout and pick up recording equipment.

Public roads, existing private roads, and vehicle routes are used. Off-road cross-country travel may be necessary to carry out tasks. Motor graders and (or) dozers may be required to provide access to remote areas. Concern about unnecessary surface disturbance has prompted government and industry personnel to plan surveys more carefully. As a result, earth-moving equipment is now rarely used in seismic

exploration work. Several trips a day are made along a seismograph line; this usually establishes a well-defined two-track vehicle route. The repeated movement back and forth along the line (particularly by the light-weight pickup trucks) defines the vehicle route. Spreading vehicles out so that vehicle routes are not straight and vehicles do not retrace the same route has, in some cases, prevented the establishment of new vehicle routes, thus reducing impacts. Drilling water, when needed, usually is obtained from the nearest source.

Each of the foregoing exploration methods has inherent strengths and weaknesses, and explorationists must decide which method will produce the most useful information, while being practical in regard to surface constraints (such as topography). Economics and past information also play a role in determining which method should be used. Reconnaissance type gravity and geomagnetic surveys can be conducted in areas where little information is available with the attendant lower costs and less impacts. More expensive and higher impact seismic surveys are conducted when more detailed information is required.

Geophysical Management (Permitting Process)

Geophysical operations on and off an oil and gas lease are reviewed by the appropriate federal surface management agency (i.e., Bureau of Land Management [BLM], U.S. Bureau of Reclamation, or U.S. Forest Service). Private and state surface land also is reviewed, but authorized by the Wyoming Oil and Gas Conservation Commission (WOGCC). Good administration and surface protection can be accomplished only through close cooperation between the operator and the impacted agency. Over an 8-year period (from 1995 through 2002) the Casper Field Office has processed 33 seismic exploration notices or permits (see Table D-1) on public lands. An average of four notices or permits can be expected to be processed each year.

Table D-1. Seismic Exploration Permits on Public Lands

Year	Number of Permits Approved
1995	5
1996	1
1997	3
1998	8
1999	6
2000	5
2001	1
2002	4
TOTAL	**33**

Note: Most of the seismic activity occurring within the Casper Field Office over the last 5 years has been 3-D seismic-authorizations related.

The responsibilities of the geophysical operator and the Field Manager are as follows:

- **Geophysical Operator –** An operator is required to file with the Field Manager a "Notice of Intent to Conduct Oil and Gas Geophysical Exploration Operations" (Notice of Intent). The Notice of Intent shall include a map showing the location of the line(s), all access routes, and ancillary facilities. The party filing the Notice of Intent shall be bonded. A copy of the bond or other evidence of satisfactory bonding must accompany the Notice of Intent. For geophysical operation methods involving surface disturbance, a cultural resources survey also is required. A pre-work field conference may be conducted. Earth-moving equipment shall not be used without prior approval. Upon completion of operations, including required rehabilitation, the operator is required to file a "Notice of Completion of Oil and Gas Geophysical Exploration Operations"

(Notice of Completion). If an operator/lessee planned on completing seismic activity as part of a lease activity, a Sundry Notice would be required to be filed along with a Notice of Intent and appropriate National Environmental Policy Act (NEPA) documentation would be need to completed prior to approval.

- **Field Manager –** The Field Manager must contact the operator after the Notice of Intent is filed and apprise the operator of the practices and procedures to be followed prior to commencing operations on BLM-administered lands. After the operations are completed, as specified by the Notice of Completion, the Field Manager shall complete a final inspection and notify the operator if the terms and conditions of the Notice of Intent have been met or that additional action is required. Consent to release the bond or termination of liability shall not be granted until the terms and conditions have been met.

State Standards

In Wyoming, the operator is required to register with the WOGCC. WOGCC standards for plugging shot holes, personnel safety, and so on, will be followed as specified in a memorandum of understanding (MOU) between the BLM and the WOGCC dated September 13, 1994, BLM MOU WY920-94-09-79. The MOU was entered into by and between the BLM and the WOGCC in accordance with the Federal Land Policy and Management Act (FLPMA).

Mitigation

Seasonal restrictions are 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 plugged properly.

OIL AND GAS 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. Based on the Federal Onshore Oil and Gas Leasing Reform Act of 1987, all leases must be exposed to competitive lease sales. Lands, for which bids are not received at the lease sale, 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 and noncompetitive leases are issued for a term of 10 years or for as long as oil and/or gas are produced. The federal government receives yearly rental fees on nonproducing leases. Royalty is received at the rate of 12.5 percent of the total saleable production, one-half of which is returned to the State of Wyoming.

In January 2003, federal oil and gas leases covered 1,738,185 acres, or about 39 percent of the federal mineral estate in the planning area. About 27 percent of the acreage leased was held by oil and gas production. Acreage leased is almost entirely in Natrona and Converse counties.

Lease stipulations may be attached to each parcel and become part of the lease after sale. Initially, stipulations are attached to a parcel by the state office leasing section from various databases. The parcel list is segregated and sent to the field office that has the majority of the parcel lands in its area. In the field office, the parcel is reviewed by the Wyoming Game and Fish Department and a BLM group of resource and NEPA specialists to ensure that lands conform to the Resource Management Plan (RMP), the stipulations are correct, and that any missing stipulations are included. This completes the process and allows the parcel to be included in a sale package.

The authorized officer has the authority to relocate, control timing, and impose other mitigation measures under Section 6 of the Standard Lease Form and in accordance with 43 Code of Federal Regulations (CFR) 3101.1-2. This authority is invoked when lease stipulations are not attached to the lease or new resources are discovered on a lease. Lease stipulations are conditions of lease issuance that provide protection for other resource values or land uses by establishing authority for delay, site changes, or the denial of operations within the terms of the lease contract. These stipulations adhere to the Uniform Format for Oil and Gas Lease Stipulations prepared by the Rocky Mountain Regional Coordinating Committee in March 1989. The stipulations are specified for each applicable parcel in the Notice of Competitive Oil and Gas Lease Sale and are intended to inform interested parties (i.e., potential lessees, operators) that certain activities will be regulated or prohibited unless the operator and the surface management agency arrive at an acceptable plan for mitigation of anticipated impacts. These stipulations are attached to the whole lease, regardless of whether the protection measure is in only a specific portion of the lease. Lease stipulations are developed during land use planning based on the known resource requirements and land uses as specified in NEPA documentation. New science, comprehensive documentation of resource requirements, land pattern interference, and ongoing monitoring of the effectiveness of a stipulation may allow granting of a waiver, exception, or modification to a stipulation. A lease stipulation waiver is a permanent exemption to a lease stipulation. An exception is a one-time exemption to a lease stipulation and is determined on a case-by-case basis. A modification is a change to the provisions of a lease stipulation either temporarily or for the term of the lease.

Drilling Permit Process

A federal lessee or the operator of record is governed by procedures set forth by the Onshore Oil and Gas Order Number 1 (as revised), "Approval of Operations on Onshore Federal and Indian Oil and Gas Leases," issued under 43 CFR 3164. These procedures cover the full gamut of operations on federal oil and gas leases from initial permitting of the well to subsequent operations to final abandonment. In the initial permitting process, the operator selects the location of a proposed drill site. This selection is based on WOGCC spacing requirements, the subsurface geology, the topography, and the avoidance of known protected surface resource values.

Spacing requirements are established by the WOGCC to protect the correlative rights of offsetting mineral owners and efficiently recover the resource. This applies to all mineral ownership (i.e., fee, state, and federal minerals). The spacing requirements are considered to be located at the subsurface point of production. Wells must be drilled within 200 feet of the center of a legal subdivision, such as a quarter section, depending on the spacing assigned to the particular area. A proposed location may be moved beyond the designated tolerance by a spacing exception granted by the WOGCC. A spacing exception requires notification of the offsetting mineral lease owners and, if there is a protest, the matter must be presented at a public hearing with full evidence of the need to relocate the well before a decision can be made by the WOGCC. The general spacing rules for the WOGCC is one well per 40 acres. Well spacing in the planning area, however, varies from one well per 10 acres in the Salt Creek Oilfield to one well per 640 acres.

BLM may require a lessee to drill a well if it is determined federal minerals are being drained by an adjacent well completed in private or state minerals. This can cause conflicts with sensitive surface resources if after a thorough environmental review, it is determined the economics are not sufficient to directionally drill a well away from the sensitive resource.

Permitting

After the operator makes a decision to drill a well, the well, access road, and pipeline can be surveyed and staked without notice to the BLM. Cultural resource inventories also can be obtained without notice.

Notice of Staking (NOS)—After the operator makes the decision to drill a well, the operator must decide whether to submit an NOS or an application for permit to drill (APD). The NOS is an abbreviated notice that includes an NOS form, a staked location map, and a sketched site plan. This notice is posted for a 30-day public review and begins the processing timeframe for approval of the APD. The NOS triggers the on-site inspection of the well site, which determines whether any conflicts with surface resource values are evident, as well as provides the preliminary data to assess which additional items are necessary to complete the APD.

Application for Permit to Drill (APD) – The operator can submit a completed APD in lieu of an NOS, but, in either case, no surface-disturbing activity can be conducted in conjunction with drilling operations until the Field Manager approves the APD.

If the APD option is used, an APD is submitted to the Field Manager and a field inspection is held with the operator and any other interested party. The purpose of the onsite field inspection is to evaluate the operator's plan, to assess the situation for possible impacts (surface and subsurface), and to formulate resource protection stipulations. To lessen environmental impacts, a site can be moved, reoriented, or resized, within certain limits defined in 43 CFR 3101.1-2, at the onsite inspection. The proposed access road or pipeline also can be rerouted. If necessary, site-specific mitigations can be added to the APD as Conditions of Approval (COA) for protection of surface and/or subsurface resource values in the vicinity of the proposed activity.

The Casper Field Office is responsible for preparing environmental documentation necessary to satisfy the NEPA requirements and for providing any mitigation measures needed to protect the impacted surface resource values. Consideration also is given to the protection of subsurface water resources. When processing an APD, the BLM geologist is required to identify the maximum depth of usable water as defined in Onshore Oil and Gas Order No. 2. Usable water is defined as that water containing 10,000 parts per million (ppm) or less of total dissolved solids. Water of this quality is to be protected usually by surface casing and cement. Determining the depth to fresh water requires specific water quality data in the proposed well vicinity or geophysical log determination of water quality, depending on existing well proximity and log availability. If water quality data or logs from nearby wells are not available, the area within a 2-mile radius of the proposed well is checked for water wells. If wells exist, surface casing is required to be set below the deepest fresh water zone found in these wells or to be placed below a depth reasonably estimated for future water wells. Usable water can be found at considerable depths and be below the surface casing setting point. In this case, surface casing is set through the fresh surface waters, and cement is required to protect the remaining useable water from the underlying nonuseable water. The depth of the casing is specified to be below a depth reasonably anticipated for future useable water recovery.

When final approval is given by the BLM, the operator can commence construction and drilling operations. Approval of an APD is valid for 1 year. If drilling does not begin within 1 year, the APD can be cancelled or stipulations can be revised prior to extending the APD for another year.

Economic conditions dramatically affect drilling activity and at the present time, oil and gas markets are buoyant nationwide. However, a downturn in the petroleum market could create a significant decrease in the number of drilling wells. Lower prices potentially could reduce the number of coalbed natural gas (CBNG) wells drilled because of the higher cost of these operations. Increases in activity have occurred over the past 3 years because of high gas prices. The Casper Field Office approved 37 drilling applications in 2000, 26 in 2001, 117 in 2003, and 162 in 2004. Approximately twice that number of fee and state wells has been approved.

Drilling depths in the planning area range from a few hundred feet in the Powder River Basin CBNG wells area to more than 19,000 feet in the Wind River Basin. The vast majority of the wells drilled in the resource area require 30 to 90 days to drill and complete. Some deep wildcat wells (17,000 to 20,000 feet) may require a year or more to drill and complete.

Rights-of-Way Requirements

Before an APD can be approved for some projects, a rights-of-way (ROW) may be required. If the project access road (including water haul road), pipeline, or powerline crosses public land outside the oil and gas lease or unit, ROW authorization may be required in addition to an approved APD for the well.

If an ROW is needed, payment of processing and monitoring fees to reimburse the United States for the processing and monitoring costs will be required. In addition, under new 2005 ROW regulations, the operator will be required to pay rental fees for the use of the ROW on federal land. ROWs associated with drilling a well may be granted for the duration of production from the well.

An ROW is not required for "casual use." Examples include driving vehicles on existing roads, sampling, surveying, marking routes, collecting data to prepare an application for a proposed oil and gas well or ROW, and performing certain activities that do not cause any appreciable disturbance or damage to the public lands, resources, or improvements. The regulations governing ROWs are contained in 43 CFR Group 2800.

Surface Disturbance Associated With Exploratory Drilling

Upon receiving approval to drill the proposed well, the operator moves construction equipment on existing roads to the point where the access road will begin. Generally, the types of equipment include dozers (track-mounted and rubber-tired), scrapers, and motor-graders. Moving equipment to the construction site requires moving several loads (some overweight and over width) on public and private roads. Existing roads and vehicle routes are improved in places and occasionally culverts and cattle guards are installed as specified in the approved APD.

The length of the access road varies. Generally, the shortest feasible route is selected to reduce the haul distance and construction costs. Environmental factors or the landowner's wishes may dictate a longer route. In rough terrain, the type of construction is sidecasting (using the material taken from the cut portion of the road to construct the fill portion); slightly less than one-half of the roadbed is on a cut area and the rest is on a fill area. Roads are constructed to BLM standards, usually with a l4-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. The total acreage disturbed for each mile of access road constructed varies according to the steepness of the slope.

Well locations are constructed by one of three different general types of construction, but, in every case, all soil material suitable for plant growth is first removed and stockpiled in a designated area. Sites on flat terrain usually require little more than removing the topsoil material 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 recovered easily for rehabilitation. It is important to confine extra cut material 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 and the depth and type of the well. The amount of level surface required averages 300 by 400 feet and should be constructed so that the drill rig can be placed on the cut surface instead of fill material to prevent the derrick from leaning or toppling as a result of the settling of uncompacted fill material.

In addition to the drilling rig footprint, a reserve pit is constructed, usually square or oblong, but sometimes in another shape to accommodate topography. 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. Depending on the relationship of the location to natural drainages, it may be necessary to construct water bars or diversion ditches. The area disturbed for construction depends largely on the steepness of the slope. Depending on the soil permeability, pits can be lined with an impermeable material to contain the drilling fluids. If water is encountered while digging the reserve pit, a closed mud system, comprising steel tanks, may be required. For oil base mud, closed systems usually are mandatory, and the mud and cuttings must be recycled or disposed of in an approved manner.

Usually, drilling activities begin within a week or two after the location and access road have been constructed. The conventional drilling rig and associated equipment are moved to the location and erected. Moving a drilling rig may require moving 10 to 25 truckloads of equipment on public highways and private roads. The derrick, when erected, is approximately 160-feet high. Drilling rigs for CBNG wells are much smaller, usually truck-mounted, require fewer loads, and are less structurally imposing.

Water for drilling is hauled to rig storage tanks or transported by surface pipeline. Water sources are usually existing water wells or commercial water sources. 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 and any applicable BLM surface use permits. When drilling commences, and as long as it progresses, water is continually transported to the rig location. Approximately 5,000 barrels (or 210,000 gallons) of water are required to drill an oil or gas well to the depth of 9,000 feet. More water is required if circulation is lost or permeable zones are encountered that cannot withstand the pressure of the drilling fluid.

Drilling Operations

Rotary Drilling

Initially, drilling proceeds rapidly because of the less competent nature of shallow formations. Drilling is accomplished by rotating the drill string and putting variable weights on the bit located at the bottom of the string. While drilling, the derrick and associated hoisting equipment bear a majority of the drill string's weight. The combination of rotary motion and weight on the bit causes rock to be gouged away at the bottom of the hole. The rotary motion is created by a square or hexagonal rod called a kelly, which fits through a square or hexagonal hole in a large turntable called a rotary table. The rotary table sits on the drilling rig floor and as the bit advances, the kelly slides down through it. When the kelly has gone as deep as it can, it is raised, and a new piece of drill pipe about 30 feet in length is attached in its place. The drill pipe is then lowered, the kelly is reattached, and drilling recommences. When the bit becomes dull, it is necessary to "trip" the drill string and replace the bit. This is a time-consuming process of withdrawing 90-foot sections of the drill pipe until the bit is out of the hole. This process requires a large part of the total drilling time and may cause other hole problems. New bits constructed with modern metals and manufactured polycrystalline diamonds, along with down-hole mud motors, have revolutionized drilling operations, whereby thousands of feet of hole can be drilled with one bit run. The mud motor is turbine-driven by high-pressure mud and is placed at the top of the bit to enable more rotational power to be transmitted to the bit, thus increasing penetration rates.

Drilling mud is circulated through the drill pipe to the bottom of the hole, through the bit, up the annulus of the well, across a screen that separates the rock chips, and into holding tanks from which finer sediments settle from the mud before it is pumped back into the well. The mud is maintained at a required weight and viscosity to cool the bit, reduce the drag of the drill pipe on the sides of the hole, seal off any porous zones, contain formation fluids to prevent a blowout, and bring the rock chips to the surface for disposal. Various additives are used in maintaining the mud at the appropriate viscosity and

weight. Most of the mud consists of bentonite, a naturally occurring mineral that is mined in Wyoming. Some of the additives are caustic, toxic, or acidic, but these hazardous additives are used in small amounts during the drilling operations and later contained within the reserve pit.

Drilling is usually accomplished with water or light mud to depths within about 1,000 feet of the prospective formation. Water and natural clays recovered during the drilling operation or light drilling mud allow fast drilling rates and the attendant reduction in mud chemicals. Once the bit reaches the target depth, the mud system gradually is made more sophisticated by adding bentonite, chemicals, and natural weight materials to reduce water loss to the potential producing zones and to control the subsurface pressure. In almost all cases, the subsurface pressure is higher than an equivalent water column and it is necessary to increase the mud weights to control the pressure and prevent a blowout or uncontrolled flow of formation fluids. Many wells are drilled in an underbalanced condition whereby the mud pressure is slightly less than the formation pressure, which increases the penetration rate and reduces the time on the well or in the formations of interest. This reduces the potential of damaging the formation, with the attendant loss of flow capacity and recovery. The wells are always overbalanced for safety requirements when a bit trip is made, the well is logged, or the casing is installed.

Drilling operations run continuously 24 hours a day, 7 days a week. The crews usually work three 8-hour shifts or two 12-hour shifts a day. Pickup trucks or cars are used for workers' transportation to and from the site. On remote isolated sites, a camp may be established to house the crews, reducing the travel requirements. Other operations, such as cementing, running casing, and rig maintenance will require road travel, sometimes with heavy equipment.

Upon completion of drilling operations, a determination is made regarding the productive potential of the well. If oil or gas is not discovered in commercial quantities, the well is considered dry. The operator is then required to follow BLM procedures to properly plug the dry hole. The drill site and access road are then rehabilitated in accordance with the COA attached to the APD and the plugging approval. If the well is a producer, drilling rig operations continue until the production casing is cemented into the well prior to removing the drilling equipment from the location.

Logging

Geophysical logs are obtained by running various instruments into the hole on a wire cable. Logs are usually run at a depth point where casing will be installed. A log usually is not run before surface casing is set, but in most instances, log-recording natural gamma radiation is run through the surface casing to determine the geology of that section. Logs can help determine water resistivity, hydrocarbon saturations, natural gamma radiations, porosity of the rock by density, nuclear receptivity and sonic measurements, permeability, pressure, temperature, hole geometry, and subsurface track. Logs are used to evaluate whether the well is dry or has the potential for a satisfactory completion. Logs also delineate the various geologic horizons; hydrocarbon zones; fresh, usable, and unusable water; and sands, shale, limestones, coals, and other minerals. The hydrocarbon intervals usually are randomly situated in each well, and logs are required to specify these intervals so that they can be perforated and stimulated during the completion program. Normally, logs recording resistivity and a combined porosity log of density and nuclear receptivity are run in the well. The dual porosity logs are a direct indicator of gas because the measured values can be compared to provide contrasting porosities.

Casing

Various types of casing are placed in the drilled hole to enhance completion operations and safety. Casing is a string of steel pipe composed of approximately 40-foot lengths of pipe that are threaded together. Casing is cemented into the well to protect against migration of fluids within the hole and to isolate the productive zones so they can be completed and produced without interference from other zones

containing hydrocarbons or water. Hole deviation, depth, bore hole environment, placement of centralizers (if any), and a myriad of other factors affect the integrity of the casing and cement job and must be considered in the original design.

Surface casing that is properly set and cemented also protects surface aquifers from contamination by drilling and production operations. Surface casing should be set to a depth greater than the deepest fresh water aquifer that could be reasonably developed. The operator shall isolate fresh water-bearing and other usable water containing 5,000 ppm or less of total dissolved solids (TDS) and other mineral bearing zones and protect them from contamination (43 CFR 3162.5-2). Usable water may exist at great depths, but these aquifers are not normally considered to be important water sources. Surface casing is designed to be large enough to allow subsequent strings of smaller casing to be set as the well is drilled deeper. Cement is placed in the annulus of the surface casing from casing shoe to ground level. The surface casing is the first string on which blowout prevention equipment is installed. The blowout prevention allows the well to be shut-in at any time that conditions warrant, protecting against unanticipated formation pressures and allowing safe control of the well. 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 part of Onshore Order No. 2. Well-trained rig personnel are a necessity for proper blowout prevention.

Generally, only the bottom portion of intermediate or production casing is cemented, which often leaves some uncemented intervals behind the casing. The annulus is filled with sufficient cement to provide adequate protection from interzonal migration of unsuitable water and hydrocarbons. Production casing or production liner is designed to provide isolation of oil and gas formations and to provide a high-pressure conduit to the hydrocarbon zones that allows stimulation of these intervals to improve the productivity.

During completion operations, the production casing or liner is perforated into zones containing the oil or gas. A zone of low permeability (ability to permit fluid flow) might require “fracturing” with a medium such as water to carry sand or other proppants designed to hold open the artificially created flow channels or fractures. Several zones in one well may be stimulated in this manner and flowed back to remove debris and excess proppant, and to determine if commercial hydrocarbon producing rates can be established. This process might be used for both gas and oil wells; testing of multiple zones can require a period of several weeks. Once completion operations are finished, wellhead and production equipment is installed.

Oil and Gas Exploratory Units

Surface use in an oil or gas field may be affected by unitization of the leaseholds. In areas of federal and mixed mineral ownership, an exploratory unit can be formed before a wildcat exploratory well is drilled. The boundary of the unit is based on geologic data and attempts to consolidate the interests in an entire structure or geologic play. The developers of the unit enter into an agreement to develop and operate as a single entity, without regard to separate lease ownerships. Costs and benefits are allocated according to agreed-upon terms. Development in a unitized field can proceed more efficiently than in a field composed of individual leases because competition between lease operators and drainage considerations is not a primary concern. Unitization also can reduce surface use requirements because all wells are operated as though under a single lease, and operations can be planned for more efficiency. Duplication of field-processing facilities is eliminated, and consolidation of facilities into more efficient systems is probable. Unitization also can involve wider spacing than usual or spacing based on reservoir factors rather than a set rule. This could result in fewer wells and higher recovery efficiency. The WOGCC allows wells to be placed in units at any location as long as they are placed within 1,120 feet of the unit

boundary. Through planning, access roads usually are shorter and better organized, facilities usually are consolidated, and well efficiency is maximized to a degree not seen in individual lease operations.

Fifty-six oil and gas unit agreements are lying wholly or partly within the planning area. These units encompass approximately 345,757 acres, or about 4 percent of the planning area. Thirty-four of the units have been primarily oil production. The remaining units primarily produce either gas or substantial quantities of both oil and gas. The oldest unit, Salt Creek, was established in 1939. No CBNG units have been established in the planning area.

Field Development

Full field development is analyzed in an Environmental Assessment or Environmental Impact Statement (EIS) after sufficient confirmation wells are drilled. The operator generally can estimate the extent of drilling and disturbance required to extract and produce the oil and gas at that time. Many fields go through several development stages. A field can be considered fully developed and produce for many years when it is determined that a well can be drilled to a deeper pay zone or a new interval is discovered to be economically attractive. In this situation, there is generally little new disturbance because the old well bores or the old well pads are used for the new completions. A new stage of field development, such as infill drilling, can lead to increases in roads and facilities. All new construction, reconstruction, or alterations of existing facilities, including roads, flow lines, pipelines, tank batteries, or other production facilities must be approved by the BLM and may require a new environmental document. Throughout field development, partial restoration and rehabilitation is required to reduce the surface impacts to the minimum required to produce the resource.

The most important factor in further development of an oil or gas field is the economics of production. When an oil or gas discovery is made, a well-spacing pattern can be established before development drilling begins. This depends on the current statewide or area-wide spacing. Well spacing is regulated by the WOGCC. Factors considered in the establishment of a spacing pattern include data from the discovery well that translate into recovery efficiency. These data include porosity, permeability, pressure, composition of reservoir and fluids, depth of formations, well-production rates, and the economic effect of the proposed spacing on recovery. These data are relatively sparse in the initial phase of development and extended production permits refinement of these values. Because these data are so tentative, the WOGCC tends to define large spacing until the data are more conclusive. The statewide spacing for oil production is 40 acres. Spacing for oil wells usually varies from 40 to 320 acres per well, but can be as little as 2-½ acres per well. Spacing for gas wells is generally from 160 to 640 acres per well, but may be as small as 10 acres if reservoir recovery efficiency dictates that spacing. Spacing requirements can pose problems in selecting an environmentally sound location or in the cumulative overall impacts. Reservoir characteristics determine the most efficient spacing to achieve maximum recovery. If an operator determines that a different spacing is necessary to achieve maximum recovery, the state (with input from the BLM) may grant exceptions to the spacing requirements.

Production

Gas, oil, and water are being produced in the planning area by means of natural flow and artificial lift (gas and electric pumping units and submersible pumps).

Gas Production

A typical gas well facility contains methanol injection equipment (to keep production and surface lines from freezing), a separator (which separates gas, oil, and water), a dehydrator (which uses glycol or calcium chloride to extract entrained water in the gas), and an orifice meter. An intermitter is sometimes used to either shut-in the well to build up pressure or to blow the well down if it is being loaded with fluid. If the gas well is producing some oil or condensate, oil tanks are used to store the oil or condensate

until it is sold via truck or pipeline. Pipeline quality gas at the wellhead requires a minimum of processing equipment. As the quality of gas decreases with the increased presence of water, solids, or liquid hydrocarbons, the amount of processing equipment increases. Water or liquid hydrocarbons in the gas are removed before the gas is sold, usually in the separation equipment near the wellhead. If liquid hydrocarbons are present, storage facilities (tank batteries) are required to store the liquids until they accumulate in sufficient quantities to be hauled out by large trucks. Gas dehydration equipment also may be present to remove water entrained in the gas to a water content defined by pipeline specifications. In 2002, 62.9 billion cubic feet of natural gas (or 3.6 percent of Wyoming's total gas) was produced in the planning area. Gas production was 39 percent more than in 1974, a 4.9 percent annual increase in production. These data are compiled from WOGCC files. Gas production curves are included in the Reasonable Foreseeable Development (RFD) scenario for oil and gas developed for the planning area. The RFD is available at www.blm.gov/rmp/casper.

Gas that occurs with oil is separated and either vented at the tank battery when uneconomical to capture and sell or collected into feeder lines leading to compressors that boost the pressure to the transportation system. If enough casinghead gas is separated to make it economical for marketing, a plant can be constructed to process the gas, or a pipeline can be constructed to carry the product to an existing plant. If the volume of casinghead gas is insufficient to warrant treatment in a gas plant, it is usually used as fuel for pump engines in the field or as heating fuel for the heater-treaters. Gas is flared or vented into the atmosphere if it exceeds the fuel requirements on the lease but is not in commercial quantities. Wyoming law prohibits the flaring or venting of natural gas. Exceptions allowed by the WOGCC are (1) during testing of a new well, or (2) when the amount of gas produced with the oil is so small that pipeline construction is not practical. Otherwise, if a well produces both oil and gas, provisions for conserving the gas must be made before oil production can continue. BLM Notice to Lessee 4A requires that all gas that is not used on the lease, vented, or flared without prior authorization either by the BLM or the WOGCC/BLM or avoidably lost, is subject to royalty obligations. Standard APD COAs allow only 30 days of testing or 50-million cubic feet of vented or flared gas, whichever occurs first. If it is found that gas is produced beyond this point, a determination may be made that the gas was avoidably lost and subject to royalty obligations.

Oil Production

Oil is generally produced using artificial lift methods (pumping units). The oil production equipment, heater-treater, tank battery, and holding facility for production water are either placed on a portion of the location (on cut rather than fill) and located a safe distance from the wellhead or placed at a centralized facility that services a number of wells with pipeline connection. Earthen dikes to contain accidental spills surround the heater-treater and tanks. Either all the facilities or only the produced water pit (if present) will be fenced. Production facility colors are required to be from the standard color chart and are specified in the APD COAs.

Production from several wells on one lease can be carried by pipeline to a central tank battery. Use of a central tank battery can depend on whether the oil is from the same formation, the same lease ownership, or multiple lease ownerships and formations if a commingling agreement is approved. Generally, because of the nature of the oil, adequate separation of oil and water is obtained only through applications of heat.

The fluid stream arrives at a separator point at which the flash gas is taken off and, in most cases; this flash gas is used for lease operations. The remainder of the flash gas is either compressed and sold or flared. Flash gas is defined as solution gas liberated from the oil through a reduction in pressure. Water and oil also are being separated at this point by gravity segregation. The oil is sent to storage tanks and the water is sent to a disposal or injection facility. Two main methods of oil measurement are used—lease automatic custody transfer units and tank gauging. Measurement is required by 43 CFR 3162.7-2 and Onshore Order No. 4 to ensure proper and full payment of federal royalty.

Oil wells can be completed as flowing (those wells with sufficient underground pressure to raise the oil to the surface) or, if the pressure is inadequate, they are completed with the installation of subsurface pumps. A pumping unit usually mechanically powers the subsurface pumps. Pumping units come in a variety of sizes, the larger ones reaching a height of 30 to 40 feet. Internal combustion engines or electric motors power the units. Fuel for the engines may be casinghead gas or propane. In cases in which large volumes of water are produced with the oil, electric submersible pumps can be installed. These pumps may produce up to 6,000 barrels of fluid per day at an oil cut of one-half of 1 percent oil. In 2002, almost 6-million barrels of oil, about 10.4 percent of Wyoming's total oil production, was produced in the planning area. Oil production was about 25 percent of the oil production in 1974, a 4.8 percent average annual decrease in production. The application of enhanced oil recovery technology at the Salt Creek Field is expected to increase oil production from the planning area, at least in the short term. These data are compiled from WOGCC files. Currently, a large portion of the oil is condensate produced with natural gas. Oil production curves are included in the RFD scenario for oil and gas developed for the planning area.

Coalbed Natural Gas Production

CBNG production combines high water production rates of some oil fields with low-pressure operations of some gas fields. Because of the reservoir characteristics of coal, high water production rates are initially required to dewater the reservoir and allow gas to be liberated from cleat surfaces within the coal. In a coal reservoir, gas primarily is trapped on the face of the coal within the cleat system via molecular attraction. Pressure must be reduced to liberate the gas molecules from the coalface. The production history shows that water production rates begin high, with little or no gas. The water rate then drops at a constant rate with increasing gas rates until a maximum rate is achieved relative to the original gas saturation and reservoir pressures. The gas rate then declines to the economic limit. This process is the exact opposite of that associated with most oil and gas production, which starts at high hydrocarbon rates and low water rates and advances to low hydrocarbon rates and high water rates. The reservoir depths of CBNG production generally are shallow (less than 2,000 feet) compared with most oil and gas production in the planning area. The depth limit is based on coal permeability, which is highly sensitive to overburden weight. A CBNG operation usually comprises a high-capacity submersible or progressive cavity pump, with water produced out of the tubing, and low-pressure gas produced out of the casing. Centralized facilities collect the gas for compression to pipeline pressures and the water for disposal. Electric power usually is used to power the well pumps and is connected to the well via a subsurface cable laid with the water and gas lines. The producing well pad is very small, with only the wellhead and an insulating house to cover the wellhead. The centralized production facilities contain wellheader buildings, where the individual well gas is measured and where collection tanks, injections wells, and pumps for disposal of the water and multistage compressors are housed to bring the very low pressure gas to sales line pressure. Sometimes the water can be disposed of in the local drainages if the Wyoming Department of Environmental Quality (DEQ) and the BLM approve of this type of disposal. Currently, CBNG production in the planning area is in its infancy, and little history is available regarding its economics and production rates. As of January 2005, only 50 CBNG wells had been drilled in the planning area. Nine of these wells had been plugged, while the rest were shut-in. Little producing history is available for these wells.

Water Production

Associated water produced with the oil, gas, or CBNG is transported to an authorized disposal pit, by placing the water in lined or unlined pits, by discharging the water into surface drainages, or through subsurface injection. Water disposal is controlled by the Wyoming DEQ for surface or near-surface disposal or by the WOGCC for subsurface disposal and secondary recovery purposes. The quality and quantity of the water often dictates the appropriate disposal method, and the Wyoming DEQ has primacy through the U.S. Environmental Protection Agency (EPA) to approve surface disposal of this water.

Produced water also is used in enhanced recovery projects. The Casper Field Office has been handling large volumes of produced water for a long period of time. This area was among the first in establishing secondary recovery operations in Wyoming, with several secondary recovery units created in the late 1950s. Secondary recovery generally is considered to be water flooding of a depleted reservoir. Annual water production in the planning area was almost 350 million barrels. About 80 percent of the water production came from the Salt Creek Field and about 89 percent was from federal wells. Rates of future water production will be influenced by the completion of new CBNG wells and reduction in water production expected at the Salt Creek Field. Water production from CBNG wells could increase annual water production by about 20 percent. Enhanced oil recovery from Salt Creek Field could decrease water production by an unknown, but significant, amount.

Most water produced from the Salt Creek Field will be re-injected, while most water from CBNG wells will be discharged on the surface. Water production per (CBNG) well is expected to be about 800,000 barrels (103 acre feet) over a 7- to 8-year life.

Production Problems

Weather extremes pose problems for producers by causing roads to become impassable, equipment to malfunction, and flow lines, separators, and tanks to freeze up. Other problems producers face in the area are production of hydrogen sulfide (H_2S), carbon dioxide (CO_2), and paraffin; corrosion; electrolysis; and broken flow lines, resulting in oil and produced water spills.

Secondary and Enhanced Oil Recovery

Secondary oil recovery projects are initiated because of the limited production efficiency of primary recovery and water-flood projects. Locale can be important in enhancing oil recovery projects. Proximity to a CO_2 source is a factor in choosing a CO_2 project. A source of fresh or treatable water is needed for steam-flood or chemical projects. Accessibility of cheap natural gas is a consideration for gas injection projects. Oil and gas prices play a very important role in determining whether an enhanced oil recovery project will be viable and deciding what type of recovery project would be appropriate. A large number of older oil fields within the planning area and a number of different types of secondary projects have been used to increase production. Presently, no active hydrothermal injection projects exist within the planning area.

Gas reservoirs typically have no secondary recovery associated with the recovery of gas. This is because natural gas is produced by expansion resulting from the reduction of reservoir pressure. Typically, a high reservoir recovery factor can be expected from this expansion process unless the reservoir is of such low permeability that economics becomes a factor in the recovery efficiency. Economics is a determining factor because of the expense of operating compression facilities to reduce the reservoir pressure to the minimum.

In rare cases in which the gas is very rich and contains a large quantity of entrained liquids, secondary recovery uses inert gases such as nitrogen or dry natural gas to keep the reservoir pressure above the condensation point to produce the maximum amount of liquids. This secondary recovery process requires sweeping the reservoir with undersaturated gas to entrain and sweep out the rich gas. After this secondary process is accomplished, especially in dry natural gas secondary recovery operations, the reservoir is depressurized to recover the maximum amount of the remaining gas reserves.

Secondary recovery in coal reservoirs has been tested in the San Juan Basin and found to be technically feasible. It involves the molecular replacement of natural gas by CO_2 or nitrogen. This process has also been touted as a method of sequestering CO_2 to remove greenhouse gas from the atmosphere. A large quantity of CO_2 is being pipelined to the Salt Creek Field, which is west of the projected CBNG development, so this process potentially may be used in the future if the economics are favorable.

An oil reservoir typically contains oil, gas, and water trapped within a rock matrix under pressure. Because of the pressure, much or all of the gas is dissolved in the oil. "Primary drive" is accomplished by the expansion of gas in solution, which forces oil out of the reservoir into the well and up to the surface. Oil flowing out of the reservoir drains energy from the formation and the primary drive diminishes. To keep oil flowing in the reservoir, pressure drawdown is required, and subsurface pumps may be used to lift oil to the surface. As reservoir pressures continue to drop, solution gas in the oil escapes, forming bubbles in the pore space. These bubbles further retard the flow of oil and increase the gas saturation and flow of solution gas. This process accelerates as the pressure declines, and at some point, production rates become uneconomical, with as much as 80 percent of the original oil remaining in the reservoir. Currently, in the United States, primary oil recovery accounts for less than half of the current oil production. The remaining oil is produced via secondary and enhanced recovery techniques.

Two basic secondary recovery methods are in use: (1) water flooding and (2) displacement by gas, including CO_2. The preferred secondary recovery method is water flooding. This process involves injecting water into oil reservoirs to maintain or increase pressure. The process is usually most efficient when the pressure has not fallen to the point at which the reservoir is highly saturated with gas. Reservoir heterogeneity in the form of fractures, directional permeability, and thin zones may limit the success of this process.

The process of displacement by gas is a less popular secondary recovery technique. Historically, produced gas was considered a waste product and was flared (burned) at the point of production. 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 reservoir. 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 gas drive that displaced the oil. To achieve miscibility, the reservoir must have reasonably high pressures and temperatures and contain high-gravity oil. Many gas-injection projects use the water and gas (WAG) process (i.e., inject water and gas alternately to achieve better contact with the oil within the reservoir). Currently the high price and demand for natural gas has precluded this type of secondary recovery.

In 2002, there were 21 active water-flooding projects in 11 fields in the planning area. Essentially, all the floods are very mature, and economics becomes a major factor. Under the current high oil price environment, these floods should continue to produce, but it is estimated that within the life of the plan, many will reach their economic limit and be abandoned. A potential caveat is the potential for tertiary CO_2 injection, as described below. The State of Wyoming is currently funding a major study related to the potential for CO_2 tertiary recovery, which may result in increased incentives via the tax system to implement this potential process and extend the life of these fields.

In 2002, there were five active gas-injection projects within the planning area. Gas-injection projects are used to maintain reservoir pressures or to aid in secondary recovery of oil or for enhanced oil recovery.

Tertiary projects use improved recovery methods that not only restore formation pressure, but also improve oil displacement or fluid flow within the reservoir. They may include projects such as water-polymer floods, water-micellar floods, or water-carbon dioxide floods. In 2002, there were three active tertiary projects within the planning area.

Some reservoirs contain large quantities of heavy oil that cannot be produced using normal or secondary methods. Thermal drive processes in which heat is introduced from the surface or developed in place in the subsurface reservoir may stimulate these. In the surface introduction process, hot water or steam is injected. Raising the temperature of heavy oil reduces the viscosity and makes the oil more mobile. Thermal recovery techniques may be considered at the West Poison Spider and South Casper Creek fields

since heavy oils are present in these fields. In the in-situ process, both heavy and light oils can be processed. Spontaneous or induced ignition within the reservoir is induced by injected air to develop a fire front that burns the hydrocarbons. Evaporation of the lighter ends immediately ahead of the fire front and, later, condensation is the primary recovery mechanism. The remaining hydrocarbons are consumed by the fire and generally are not considered of any value. These techniques are very expensive and must have large reserves and thick pay zones to be economical. No active hydrothermal injections projects exist in the planning area.

Several chemical drive techniques are currently in use, including (1) polymer flooding, (2) caustic flooding, and (3) surfactant-polymer injection. These methods attempt to change reservoir conditions to allow recovery of additional oil. Caustic and surfactant-polymer flooding have not been economical in the past, and unless a breakthrough in technology is achieved, they probably will not be considered during the planning period. Polymer flooding is an economically viable process, but is used mainly in viscous reservoirs with high permeability. Currently, no such reservoirs exist in the planning area, but future discoveries could be made.

Carbon dioxide appears to have the best potential for enhanced and tertiary recovery methods. CO_2 is miscible with oil at relatively low pressures and temperatures, and can be used with oil with a wide range of characteristics. CO_2 miscibility reduces the oil viscosity and allows much more efficient displacement by water. Usually, CO_2 is injected via the WAG process in alternating slugs of CO_2 and water. Not only does CO_2 create miscible flow, but it also can displace oil by gravity segregation between the CO_2, gas, and oil. This process may allow sequestration of large volumes of the CO_2 greenhouse gas in the many applicable reservoirs in the planning area and recover the last possible oil reserves. Sequestration of CO_2 is advocated as a method to remove the gas from the earth's atmosphere by storing the gas for geologic time. Other structures within the planning area that do not contain oil also could be applicable for sequestration.

Gas Storage

Pipeline-quality gas can be stored in good quality reservoirs with excellent sealing parameters. This gas is pumped into the reservoir during nonpeak, usually lower-priced time periods, and then pumped out into the transmission lines at times of peak demand and good prices. The differential in price pays the governmental storage fees for the use of the reservoir and the injection/compression costs required to store and retrieve the gas. The differential also serves as a buffer for cold periods when demand is high and levels out the summer slack period of production. Currently, there are no active gas storage reservoirs within the planning area.

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, subsurface well design, and specific rehabilitation concerns; therefore, only minimum requirements can be established, and these must be modified for individual wells.

The first step in the plugging process is the filing of the Notice of Intent to Abandon. Both the surface management agency and the BLM petroleum engineer will review this notice. The notice must be filed and approved prior to plugging a past producing well. Verbal plugging instructions can be given for plugging current drilling operations, but a notice must be filed after the work is completed. If usable fresh water was encountered while the well was being drilled, the surface management agency may be allowed, if interested, to assume future responsibility for the well and the operator will be reimbursed for the attendant costs. This assumption of responsibility becomes effective after the deeper zones are plugged

back to the usable water zone. Usually, the operator is more than satisfied to remove the surface reclamation liability and will not charge for the remaining well equipment.

The operator's plan for securing the hole is then reviewed. The minimum requirements, as stated in Onshore Order No. 2, are as follows: In open hole situations, cement plugs must extend at least 50 feet above and below zones that have fluid with the potential to migrate, zones of lost circulation (this type of zone may require an alternate method to isolate it), and zones of potentially valuable minerals. Thick zones may be isolated using cement 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 cement plugs placed every 3,000 feet. In cased holes, cement plugs must be placed opposite perforations and extend 50 feet above and below, except where limited by plug back depth. The length of the plug is 100 feet plus 10 percent per 1,000 feet (i.e., at 10,000 feet, the plug will be 200-feet long).

Cement plugs could be replaced with a cement retainer if the retainer is set 50 feet above the open perforations and the perforations are squeezed with cement. A bridge plug also may be used to isolate a producing zone and must be capped, if placed through tubing, with a minimum of 50 feet of cement. If the cap is placed using a dump bailer, a minimum of 35 feet of cement is required. A dump bailer is an apparatus run on wire line to convey the cement to the bottom of the hole. In the event that the casing has been cut and recovered, a plug is placed 50 feet within the casing stub, and the 100 feet plus 10 percent per 1,000 feet rule is used for the space above the cutoff point. In all cases, a plug is set at the bottom of the surface casing that has a volume of cement using the 100 feet plus 10 percent per 1,000 feet rule. This may require perforating the casing and circulating or squeezing cement behind the production casing if that casing is not removed. Annular space at the surface will be plugged with 50 feet of cement using small-diameter tubing or by perforating and circulating cement.

If the integrity of a plug is questionable or the position is extremely vital, it can be tested with pressure or by tagging the plug with the tubing or drill string. Tagging the plug involves running pipe into the hole until the plug is encountered and placing a specified amount of weight on the plug to verify its placement and competency. The surface plug within the casing must be a minimum of 50 feet. The interval between plugs must be filled with mud that will balance the subsurface pressures; if this balance point is unknown, a minimum of 9 pounds per gallon is specified. After the casing has been cut off below the ground level, any void at the top of the casing must be filled with cement. If a metal plate is welded over the top of the casing, a weep hole is placed in the plate. A permanent abandonment marker is required on all wells unless otherwise requested by the surface management agency. This marker pipe is usually at least 4 inches in diameter, 10-feet long, 4 feet above ground, and embedded in cement. The pipe must be capped with the well identity and location permanently inscribed.

The surface management agency is responsible for establishing and approving methods for surface rehabilitation and determining when this rehabilitation has been satisfactorily accomplished. With satisfactorily rehabilitation, a Final Report of Abandonment is approved, and the well bond released. As of March 7, 2005, 8,073 wells, of which 5,293 are federal wells, had been plugged and abandoned in the planning area.

This page intentionally left blank.