APPENDIX 20—OIL AND GAS OPERATIONS

GEOPHYSICAL EXPLORATION

Oil and gas can be discovered by either direct or indirect exploration methods, such as the mapping of rock outcrops, seeps, borehole 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 may provide information that increases the chances of drilling a discovery well and information that may discourage drilling and the associated surface disturbance. More sophisticated geophysical techniques, like three-dimensional (3-D) seismic surveys, may supply enough information to model a reservoir and optimize drilling to prevent excess wells and the associated surface 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 are generally not considered definitive because of the many corrections required (e.g., terrain, elevation, latitude) 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, and the gravimeter is transported either by backpack, helicopter, or offroad vehicle. The only surface disturbance associated with gravity prospecting is that caused by a vehicle, if used.

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 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 those 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 resolution and are considered 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 are nearly identical to gravity surveys and 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. 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, and this value is mapped to give an underground picture of the geologic structure.

There are many methods available today that an explorationist can use to induce the initial seismic energy into the earth. All methods require preliminary surveying and laying 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 forward 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 drills that drill small-diameter holes to depths of 100 to 200 feet. Four to 12 holes are drilled per mile of line. Usually, a 50-pound charge of explosives is placed in the hole, covered, and detonated. The detonated explosive sends a shock wave below the earth's surface that is subsequently reflected back to the surface from various subsurface rock layers. In rugged topography, a portable drill is sometimes 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 obtain the greatest amount of geologic information.

Seismic information can be obtained in two-dimensional (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 can often be changed to significantly 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, by which method is used.

A typical drilling seismic operation can use 10 to 15 men operating 5 to 7 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 pickup trucks for the surveyors, shot hole crew, geophone crew permit man, and party chief.

Public roads and existing private roads and vehicle routes are used. Off-highway cross-country travel may be necessary to carry out tasks. Motor graders and/or dozers may be required to provide access to remote areas. Vehicle use for necessary tasks, such as geophysical exploration, including project survey and layout, would be permitted. Concern about unnecessary surface disturbance has caused government and industry to more carefully plan surveys. As a result, earth-moving equipment is now only 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 the light 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 and has reduced impacts. Drilling water, when needed, is usually obtained from the nearest source.

Each of the foregoing exploration methods has inherent strengths and weaknesses, and explorationists must decide which method is the most practical with regard to surface constraints (such as topography) while still producing useful information. Economics and past information also plays a role in determining the method used. Reconnaissance type surveys of gravity and geomagnetic can be run in areas where little information is available, with the attendant lower costs and less impacts. More expensive and higher impact seismic surveys are run 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 (SMA) (i.e., Bureau of Land Management [BLM], Bureau of Reclamation, or U.S. Forest Service). Good administration and surface protection can only be accomplished through close cooperation between the operator and the affected agency. During a 10-year period (from 1994 through 2003) the Rawlins Resource Management Plan Planning Area (RMPPA) has processed 40 seismic exploration notices or permits (Table A20-1) on public lands. An average of four notices or permits can be expected to be processed in any year.

Table A20-1. Seismic Exploration Permits on Public Lands

Year	Number of Permits Approved
1994	1
1995	1
1996	1
1997	4
1998	5
1999	11
2000	5
2001	3
2002	5
2003	4
TOTAL	**40**

The responsibilities of the geophysical operator and the field manager are as follows (USDI 1989b):

- **Geophysical Operator—**An operator is required to file with the field manager a "Notice of Intent (NOI) to Conduct Oil and Gas Exploration Operations." 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. For geophysical operation methods involving surface disturbance, a cultural resources survey is also 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 Exploration Operations."

- **Field Manager**—The field manager shall contact the operator after the NOI 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 NOI 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 Wyoming Oil and Gas Conservation Commission (WOGCC). WOGCC standards for plugging shot holes, personnel safety, and so forth, will be followed as specified in a memorandum of understanding (MOU) between the BLM and the State of Wyoming 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 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 properly plugged.

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 12½ percent of the total saleable production, one half of which is returned to the State of Wyoming.

The Energy Policy and Conservation Act Amendments (EPCA) of 2000, Public Law (PL) 106-469, directed the Secretary of the Interior to conduct an inventory of oil and natural gas resources beneath federal lands. The Act also directed the Department of Interior to identify the extent and nature of any restrictions to resource development. As a result, the Departments of the Interior, Agriculture, and Energy released a report, Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development (referred to as the "EPCA Phase II Inventory"), in November 2006.

BLM is integrating the results of the EPCA inventory into its RMPs. The oil and gas resource inventory data are integrated into the RFD scenario that predicts future mineral development within the RMPPA. The restrictions and impediments to mineral resource development are considered throughout the RMP with the intent to—

- Clearly present mitigation requirements necessary to reduce impacts of oil and gas operations on other resources
- Ensure that such mitigation is either statutorily required or scientifically justifiable and is the least restrictive measure necessary to accomplish the desired level of resource protection. The mitigation requirements would be monitored to determine if more or less restrictive measures might accomplish the same goal.

Oil and gas lease stipulations may be modified or eliminated using the exception, modification, or waiver criteria outlined in this RMP (Appendix 9) or through more site-specific environmental analysis. Those stipulations that are either too restrictive or too lenient to accomplish the desired resource protection would be changed if monitoring or new scientific data justify the change. Clarifying changes may be made to the wording of oil and gas lease stipulations as long as there is no substantial change to the mitigated protection, as justified by new scientific data or monitoring.

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 a group of resource and National Environmental Policy Act (NEPA) specialists to ensure that lands are in conformance with 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, provided appropriate environmental documentation can justify the modification. 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 (potential lessees, operators) that certain activities will be regulated or prohibited unless the operator and the SMA 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 only be in a specific portion of the lease. Lease stipulations are based on the perceived 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 No. I, “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 minerals, 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 foot 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 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 WOGCC. The RMPPA has a specified spacing density of 160 acres throughout most of the high and moderate potential areas. The rest of the RMPPA is spaced at 40 acres, which is the standard statewide rule. Forty acres is not a probable future spacing, except in specific instances, because spacing is based on the most efficient recovery of the reserves. The probable maximum subsurface density of wells is 160 acres throughout most of the RMPPA, with certain areas having a subsurface density of 80 acres, based on the currently projected recovery efficiencies and economics. Spacing of 640 acres, or 1,280 acres per well, is not unrealistic in the case of deep, expensive wells that can recover the reserves in an efficient manner. Surface density of wells would be a variable based on the surface resource conflicts, economics of directional drilling, accessibility within the checkerboard (surface locations on fee land to access federal minerals within resource conflict areas), and the subsurface density.

Occasionally, BLM may require that a lessee drill a well on a lease if it is determined that federally owned minerals are being drained by an adjacent well on private or state-owned lands. This may cause conflicts in areas of sensitive surface resources. If the economics are not sufficient to drill a directional well from a location on the federal lease, drainage protection may require compromising the sensitive surface resource after a thorough environmental review.

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 BLM. Cultural resource inventories can also be obtained without notice.

- **Notice of Staking (NOS)**—After the operator makes the decision to drill a well, it must decide whether to submit an NOS or Application for Permit to Drill (APD). The NOS is an abbreviated notice that consists of an NOS form, a staked location map, and sketched site plan. This notice is posted for a 30-day public review and begins the processing time frame for approval of the APD. The NOS triggers the onsite inspection of the well, which determines whether any conflicts with critical resource values are evident and provides the preliminary data to assess what additional items are necessary to complete the APD.

- **Application for Permit to Drill**—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 the drilling operations until the APD is approved by the field manager.

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, at the onsite inspection. The proposed access road or pipeline can also be rerouted. If necessary, site-specific mitigations are 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 field office is responsible for preparing environmental documentation necessary to satisfy the NEPA requirements and provide any mitigation measures needed to protect the affected surface resource values. Consideration is also 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 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. In the RMPPA, usable water can be available to great depths and beyond 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 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 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 within the RMPPA because much of the current activity is infill drilling or in marginal fringe areas. Lower prices could potentially 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 increased interest in obtaining gas to supply the Kern River gas pipeline to California and uncharacteristically high gas prices. The RMPPA approved 104 drilling applications in fiscal year 2000, 173 in 2001, 191 in 2002, and 183 in 2003. An approximately equal number of fee and state wells are also usually approved.

In the RMPPA, drilling depths range from a few thousand feet in the Atlantic Rim CBNG area to more than 17,000 feet in the Washakie and Hanna Basins. The vast majority of the wells drilled in the resource area require 30 to 90 days to drill and complete. Some of this time may be consumed with waiting for pipeline connections so that a "green completion" can be made. A green completion allows wells to sell gas during the early clean-up phases of the stimulation program. In the past, a lot of gas was vented or flared during this clean-up phase. Some deep wildcat wells (17,000 to 20,000 feet) may require a year or more to drill and complete.

Surface Disturbance Associated With Exploratory 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. 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) over 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 usually constructed 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 significantly with 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 easily recovered 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 soil.

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 diversions. The area disturbed for construction depends largely on the steepness of the slope. Depending upon 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, consisting of steel tanks, may be required. For oil base mud, closed systems 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 over public highways and private roads. The derrick, when erected, is approximately 160 feet high. Drilling rigs for CBNG wells are much smaller, 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 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.

Issuance of Rights-of-Way

Rights-of-way (ROW) are required for all facilities, tank batteries, pipelines, power lines, and access roads that occupy federally owned land outside the lease or unit boundary. When a third party (someone other than the operator) constructs a facility or installation on and/or off the lease, a ROW is also required.

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 so that thousands of feet of hole can be drilled with one bit run. In the RMPPA, it is not uncommon to record bit runs of 7,000 feet with one bit. The mud motor is a 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 and, thus, increase 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.

Within the RMPPA, 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 is gradually made more sophisticated by addition of 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 are continuous, 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, which will reduce the travel requirements. Other operations, such as cementing, running casing and rig maintenance, will require road travel, sometimes with heavy equipment.

Upon completion of the drilling, 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 stipulations 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 is not usually run before surface casing is set but, in most instances, a log recording natural gamma radiation is run through the surface casing to determine the geology of that section. The logs can 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, shales, limestones, coals, and other minerals. The hydrocarbon intervals are usually 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 in the RMPPA, 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. 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 (BOP) equipment is installed. The BOP 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 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 few thousand feet of intermediate or production casing is cemented, which often leaves several thousand feet of open hole behind some casing strings. In the RMPPA, the annulus is filled with sufficient cement to provide adequate protection from inter-zonal migration of unsuitable water and hydrocarbons. Production casing or production liner is designed to provide isolation of oil and gas formations and 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. In the RMPPA, the low permeability character of the productive formations requires these zones to be “fraced,” or stimulated by treated fresh water and large quantities of sand, which improves the productivity to an economic rate. Generally two and up to five stimulation treatments can be accomplished in each well. Normally, approximately 50 percent of the stimulation fluid is produced within a couple of days and the rest over an extended period at low rates. Radioactive tracers show the fracs stay within the zone, which is important to maximize the fracs productivity because a frac length is the primary factor in successfully stimulating a productive interval. After completion, operations are finished, and wellhead equipment, consisting of various valves and pressure regulators, is installed to control the oil or gas flow to the production facilities and allow safely shutting in the well under any conditions.

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 can also involve wider spacing than usual or spacing based on reservoir factor rather than a set rule. This could result in fewer wells and higher recovery efficiency. 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 are usually shorter and better organized, facilities are usually consolidated, and well efficiency is maximized to a degree not seen in individual lease operations.

Within the RMPPA are 71 non-CBNG producing oil/gas units totaling 397,213 acres. Most of the units are located in the Greater Green River Basin, with two in the Denver Basin and three in the Hanna and Laramie Basins. Almost all of these units are the product of mature agreements with a few new exploratory units located in the more prospective areas of the RMPPA. Currently, four CBNG units have been authorized, and four more are in the process of authorization, totaling 140,336 acres. Most of the CBNG units are located in the Atlantic Rim area on the eastern side of the Greater Green River Basin. Seven secondary recovery units exist in the RMPPA, primarily for the water flood recovery of oil. Two of these units are in a tertiary recovery phase using CO_2 in an alternating water/gas injection program. There are two active gas storage agreements in the RMPPA.

Field Development

New field development is analyzed in an environmental assessment or Environmental Impact Statement (EIS) after the 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 is dependent upon the current statewide or area-wide spacing. Well spacing is regulated by WOGCC, and 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, 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 2½ acres. 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 BLM) may grant exceptions to the spacing requirements.

Changes in Production for the Approved RMP

Projections of future oil and gas production for the Approved RMP for the baseline Reasonable Foreseeable Development scenario were prepared using type wells, estimated well totals, and estimated decline rates for current producing areas. Producing areas were divided into three parts: (1) coalbed gas reserves, (2) oil and gas in townships 14–24 north and ranges 90–96 west, and (3) oil and gas producing areas in the remainder of the field office. Based on historical drilling data, 75 percent of the future conventional wells are expected to be drilling in the area comprised of townships 14–24 north and ranges 90–96 west. Well totals for conventional and coalbed gas were estimated for each year in which future production is estimated.

Well location reductions from the baseline reasonably foreseeable development scenario are due to management restrictions. Restrictions can affect oil and gas development activities by not allowing leasing, not allowing surface occupancy, controlling surface use, or adding restrictive stipulations to conditions of approval on federal applications to drill. For reasonably foreseeable development scenario analysis purposes, the restrictions were separated into four classifications designated A, B, C, and D. These four classifications are consistent with the BLM Planning Handbook, H-1601-1. Restrictions on drilling are progressively more limiting from A to D and are—

- **Classification A—**Areas open to leasing, subject to existing laws, regulations, and formal orders; and the terms and conditions of the standard lease form
- **Classification B—**Areas open to leasing, subject to moderate constraints such as seasonal and controlled surface use restrictions. (These are areas where it has been determined that moderately restrictive lease stipulations may be required to mitigate impacts to other land uses or resource values)
- **Classification C—**Areas open to leasing, subject to major constraints such as no-surface-occupancy stipulations on an area more than 40 acres in size or more than 0.25 mile in width. (These are areas where it has been determined that highly restrictive lease stipulations are required to mitigate impacts to other lands or resource values. This classification also includes areas where overlapping moderate constraints would severely limit development of fluid mineral resources)
- **Classification D—**Areas closed to leasing. (These are areas where it has been determined that other land uses or resource values cannot be adequately protected with even the most restrictive lease stipulations; appropriate protection can be ensured only by closing the lands to leasing.) Identify whether such closures are discretionary or nondiscretionary; and if discretionary, the rationale.

Reductions in well locations from the base line reasonably foreseeable development scenario were determined as described below.

An estimate of the number of well locations/township that could be drilled in each development potential classification over the 20-year life of the Resource Management Plan (RMP) was made for conventional oil and gas development activity and for coalbed gas development activity. This development applies to all leased lands whether existing leases or yet to be leased.

Conventional and coalbed gas development potential maps were overlain and 10 combinations of development potentials were identified (e.g., high conventional oil and gas—moderate coalbed gas, moderate conventional oil and gas—low coalbed gas).

The acres of federal oil and gas ownership in each area were determined using GIS software. Acres of nonfederal oil and gas minerals were not included because Approved RMP decisions will only apply to federal oil and gas minerals. It was assumed that development on nonfederal minerals would occur as estimated in the baseline foreseeable development scenario.

Next, the area covered by each classification of restriction (B, C, and D classifications) within the 10 development potential areas was calculated using GIS software. The area within Classification A was not calculated because BLM previously determined that this type of restriction would have no effect on the number of well locations.

After the acres of federal oil and gas were calculated for each restriction classification, the percent reduction in well locations for each classification of restriction was estimated. That estimate was a number agreed upon by the authors of the report and is based on professional judgment. This estimate is a percent of the well locations that would not be drilled in each area due to the specific classification of restrictions.

The percent reduction for each classification of restriction and each development potential combination was determined. Then the reduction in well locations was calculated and summed for both conventional oil and gas and for coalbed gas.

From baseline (no restrictions) conditions—

- Oil production would decrease by 25.1%
- Conventional gas production would decrease by 9.6%
- Coalbed gas production would decrease by 15.2%
- Total gas production would decrease by 12.7%.

Production

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

Gas Production

A typical gas well facility consists of methanol injection equipment (to keep production and surface lines from freezing), separator (which separates gas, oil, and water), dehydrator (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 may also be present to remove water entrained in the gas to a water content defined by pipeline specifications. In the RMPPA, gas production has averaged 614,309 thousand cubic feet per day (MCFPD) for the last 4 years (starting in 2000), and this is up considerably from the production rate of 77,843 MCFPD recorded in 1978. These data are compiled from WOGCC files. Gas production curves are included in the Reasonable Foreseeable Development scenario for oil and gas that was developed for this RMPPA.

Gas that occurs with oil is separated by venting it at the tank battery; it may also be 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 (NTL4A) 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. In the RMPPA, standard APD COAs allow only 30 days of testing or 50 million cubic feet (MMCF) 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. Very little casinghead gas is produced in the RMPPA, primarily because of the mature age of the fields that may produce this gas.

Oil Production

In the RMPPA, oil is generally produced using artificial lift methods (pump 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 as a centralized facility that services a number of wells with pipeline connection. The heater-treater and tanks are surrounded by earthen dikes to contain accidental spills. 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 only obtained through applications of heat. The fluid stream arrives at a separator point where 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 are also 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 in the RMPPA 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. The subsurface pumps are usually mechanically powered by a pumping unit. Pumping units come in a variety of sizes, the larger ones reaching a height of 30 to 40 feet. The units are powered by internal combustion engines or electric motors. Fuel for the engines may be casinghead gas or propane. In cases where 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 ½ of 1 percent oil. In the RMPPA, oil production has averaged 14,504 barrels of oil per day (BOPD) for the last 4 years (starting in 2000). This is down considerably from a production rate of 21,915 BOPD recorded in 1978. 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 Reasonable Foreseeable Development scenario for oil and gas that was developed for this RMPPA.

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 is primarily 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 coal face. 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 gas 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 are generally shallow (less than 5,000 feet) compared with most oil and gas production in the RMPPA. The depth limit is based on coal permeability, which is highly sensitive to overburden weight. A CBNG operation usually consists of 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 is usually 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 well head and an insulating house to cover the well head. The centralized production facilities contain well header buildings where the individual well gas is measured and that house collection tanks, injections wells, and pumps for disposal of the water and multistage compressors 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 (WDEQ) and BLM approve of this type of disposal. Currently in the RMPPA, CBNG production is in its infancy, and little history is available regarding its economics and production rates. One project has produced about 1,965 MCFD and 6,711 BWPD over the year 2003 from 24 wells (82 MCFD/well) as compiled by WOGCC. Two other projects were abandoned after producing only water, and a third project is producing water with only small amounts of gas. The Atlantic Rim CBNG development project estimates a maximum of 250,000 to 450,000 bwpd of produced water for approximately six to eight years and the Seminoe Road CBNG development estimates about 180,000 bwpd during peak production. Actual water productions are likely to rise steadily as development occurs and wane as the pressure regime for adsorption of the natural gas is reached.

Water Production

Associated water produced with the oil, gas, or CBNG is disposed of by trucking the water 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 WDEQ for surface or near-surface disposal or by WOGCC for subsurface disposal and secondary recovery purposes. The quality of the water often dictates the appropriate disposal method, and WDEQ has primacy through the Environmental Protection Agency (EPA) to approve surface disposal of this water.

Produced water is also used in enhanced recovery projects. The RMPPA has been handling large volumes of 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 early 1960s, and one unit in 1937. Secondary recovery operations always require subsurface injection to enhance hydrocarbon recovery and, in most cases, use water. WOGCC files for the RMPPA show water production rates of 108,429 barrels of water per day (BWPD) in 1978, and this value reached a maximum of 338,925 BWPD in 1987. For the last 4 years, starting in 2000, water production rates averaged 246,473 BWPD. Essentially all of this water is injected into the subsurface with no apparent environmental harm.

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 H_2S, CO_2, and paraffin, corrosion, electrolysis, and broken flow lines.

Secondary and Enhanced Oil Recovery

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 the RMPPA, most of the reservoirs are overpressured but have very low permeability. The overpressure allows more gas to be stored but the low permeability limits the recovery to a smaller portion of the area around each well. In the RMPPA, studies show that each well will recover the reserves within only an 80-acre pattern, requiring a doubling of the wells in most of the large gas fields to fully produce the resource.

In rare cases where the gas is very rich and contains a large quantity of entrained liquids, secondary recovery uses inert gases like nitrogen or dry natural gas to keep the reservoir pressure above the condensation point in order 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 carbon dioxide or nitrogen. This process has also been touted as a method of sequestering CO_2 to remove the greenhouse gas from the atmosphere. A large quantity of CO_2 is available immediately to the west of the RMPPA, and a CO_2 pipeline is located to the northwest of the projected CBNG development, so this process may potentially be used in the future if the economics are favorable.

An oil reservoir typically contains oil, gas, and water trapped within the 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 the 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. 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 where 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 injecting 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 reinjected into the reservoir. Increased production was achieved by (1) maintaining reservoir pressure by injecting the gas into the existing gas cap and (2) 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 the RMPPA, seven secondary recovery units have been or are currently being water flooded. Most of these include reservoirs within geologic structures located around the margins of the various basins such as Denver, Laramie, Carbon, and Greater Green River. Essentially all the floods are very mature, and economics become a major factor. Under the current high oil price environment, these floods should continue to produce, but it is estimated that, within the 20-year planning period, 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.

Gas injection is not currently being used as a secondary recovery technique within the RMPPA, although it was used in the past.

The term "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) drives. Currently no enhanced recovery techniques are being implemented within the RMPPA, but it is unknown whether these techniques could be applicable in the future based on economics and new discoveries.

Some reservoirs contain large quantities of heavy oil that cannot be produced using normal or secondary methods. These may be stimulated by thermal drive processes in which heat is introduced from the surface or developed in place in the subsurface reservoir. 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 are not likely to be tried in the RMPPA because the oils present here are not heavy oils. 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 are generally not considered of any value. These techniques are very expensive and must have large reserves and thick pay zones to be economical. It is unlikely they will be used within the RMPPA in the immediate future unless new discoveries are made.

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 will probably 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 RMPPA, 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 RMPPA 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 RMPPA that do not contain oil could also be applicable for sequestration. Two tertiary recovery projects are active within the RMPPA at this time and both use CO_2. Both projects have been successful, and if prices remain high, they should recover a large volume of oil in the future. It is doubtful whether these projects will last the full 20 years unless CO_2 sequestration becomes economical via tax credit implementation.

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. It also serves as a buffer for cold periods when demand is high and levels out the summer slack period of production. There are two active gas storage reservoirs within the RMPPA.

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. This notice will be reviewed by both the SMA and RMPPA petroleum engineer. 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 SMA 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 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 may also 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, and 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 SMA. This marker pipe is usually at least 4 inches in diameter, 10 feet long, 4 feet above the ground, and embedded in cement. The pipe must be capped with the well identity and location permanently inscribed.

The SMA is responsible for establishing and approving methods for surface rehabilitation and determining when this rehabilitation has been satisfactorily accomplished. With satisfactorily rehabilitation, a Subsequent Report of Abandonment is approved, and the well bond released. As of November 3, 2003, 2,958 wells had been plugged and abandoned in the RMPPA. Over the last 3 years, approximately 20 wells per year have been plugged and abandoned in the RMPPA.