COMPARISON OF ENVIRONMENTAL REGULATION OF THE OIL AND GAS INDUSTRY IN THE ROCKY MOUNTAIN STATES AND ALBERTA

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employed, a rough estimate can be obtained of the inspector work load per state/province. However, it must be noted that work load allocation among inspectors is affected by the distribution of well locations, exploration areas and field offices, production characteristics, and numerous other factors. Actual work load may vary considerably from these estimates. Wyoming, New Mexico and Colorado had the highest number of wells per inspector, with 2,498, 2,403 and 2,119, respectively. Montana was again fourth, with 1,057 wells per inspector. Utah, Alberta and North Dakota had the lowest ratios with 411, 406 and 317 respectively. Current inspector workload in all the states and Alberta has lessened due to the dramatic decline in world oil prices and corresponding reductions in exploration and production.

Montana has the lowest budget for regulation of oil and gas activities, but it is also the only state that has not taken over administration of the Underground Injection Control (UIC) program from the Environmental Protection Agency (EPA). Field staff in Alberta, Colorado, North Dakota and New Mexico are responsible for UIC-related inspections in addition to other duties.

Geographic distribution of the industry varies considerably among the states. With the entire eastern two-thirds of its counties containing oil and gas production, Montana probably has more territory for inspectors to cover than the other states. Only two states, New Mexico and North Dakota, have concentrated oil and gas production. Gas deposits are located in much of Alberta except the northeast quarter and along the western border. Oil deposits are more concentrated in central Alberta but extend over three-quarters of the length of the province. Inspectors are located in nine district offices in order to cover this extensive territory.

B. Seismic Exploration

Seismic exploration regulations, shot hole plugging regulations and field inspection practices vary among the states primarily by the amount of information and level of contact with the regulatory agency that is required before seismic operations commence and during or after plugging. New Mexico is not included in this comparison because it has no seismic regulations.

In Montana, North Dakota and Colorado, counties issue permits for geophysical activity. Montana's statute requires the seismic exploration company to file a notice of intent with the state and the county, and also requires the county to notify the state when a permit has been issued. In practice, the counties normally telephone oil and gas division staff so there is an opportunity for discussion of the planned activity with the crews before work begins. Companies planning to engage in seismic exploration are also required to notify the surface user of the approximate time schedule, provide names and addresses of contact persons for the companies involved, and identify the number of its surety bond, the surface areas to be explored, and any anticipated needs for water. The North Dakota oil and gas statute contains similar requirements, and also gives counties authority to condition or restrict oil and gas exploration through ordinances. North Dakota oil and gas agency staff do not inspect seismic shot holes at any time. This area of regulation is considered to be exclusively under the counties' jurisdiction. In Montana, a representative sample of shot holes is inspected by state oil and gas staff after plugging is completed. Colorado's inspections also occur after plugging.

In Wyoming and Utah the state oil and gas agencies issue the exploration permits. Wyoming, Utah, Alberta and Colorado require companies to file notices of intent for each exploration operation. Content of the notices varies by state/province, and includes descriptions of the plugging procedures, depth and number of holes, names and addresses of contact persons, and time and location of the operations. Wyoming requires companies intending to conduct seismic shot hole exploration to meet with oil and gas agency staff before beginning to operate in the state to discuss regulatory requirements. Seismic operations in Utah and Alberta are usually witnessed by an inspector.

All of the states and Alberta prohibit seismic shots within a specified distance (usually ¼ mile) of buildings, springs and water wells. Utah similarly protects "cultural and natural" features. Alberta also restricts exploration in certain environmentally sensitive areas such as critical wildlife habitat on public lands. This requirement appears similar to restrictions that the U.S. Forest Service and Bureau of Land Management may put on drill permits.

All of the states except Colorado require advance notice of plugging operations. Plugging requirements are similar among the states and include specifications for materials such as bentonite and water slurries or coarse ground bentonite or cement, depending on the presence or absence of water in the hole. Montana's Board of Oil and Gas Conservation is evaluating potential changes in the regulations to require plugging with coarse ground bentonite rather than a bentonite-water slurry in certain types of holes.

Montana's statute allows surface owners and companies to agree to plugging methods other than those specified by the Board. Landowners in New Mexico also specify the plugging requirements. In other states and Alberta, the company may use alternative methods only with the approval of the oil and gas agency.

All of the states require a report subsequent to completion of plugging indicating the location and date of the operations. Colorado's is the most detailed because it must also include information about the plugging materials and procedures, and identification of any water that was encountered.

C. Permits to Drill

Permits to drill were compared in terms of application content, processing time, timing of site inspections, and authority to condition permits for purposes of environmental protection. All of the states require information about the specific location of the drill site, the name and expected depth of the targeted strata, the casing that is planned, cement points, and other aspects of the drilling program. The differences examined in this study focus on how environmental protection aspects of the drilling operation are addressed.

Alberta requires drilling plans that include descriptions of site construction and maintenance operations in addition to a description of the drilling programs. Plans for final disposal of mud and fluids must also be submitted. If the location proposed for drilling is environmentally sensitive, personnel from concerned agencies may inspect the site. The Energy Resources Conservation Board may subsequently prescribe road locations and attach environmental stipulations, as necessary, to any aspect of the drilling operation. Drill permits may also be denied.

As discussed in the next section on reserve pits, Wyoming requires certain site-specific information in a separate form that is attached to the drilling permit application. No other state requires written data describing the site location before drilling commences. However, Utah requires a pre-drill inspection before the permit is approved. The inspection includes an assessment of site soil and water characteristics in order to establish permit stipulations and pit construction requirements. North Dakota inspectors visit the drill site after the permit is approved, but before the rig arrives in order to perform the same type of assessment.

Because of the pre-drill inspection, Utah requires 7-14 days to process permits. All of the other states try to process the applications the same day they are received, unless information is missing. Montana oil and gas staff often discuss drilling plans with the crews by telephone before field work begins. In both Colorado and Montana, the first site inspection typically occurs after the permit is issued and drilling has commenced. In New Mexico site inspections typically occur after drilling is completed.

The oil and gas agencies in Utah and Wyoming may attach special stipulations concerning surface use and pit and road construction. In Montana landowners make agreements concerning road placement and surface use.

D. Reserve Pits

Drilling fluids may have very high concentrations of salt, especially chloride, and also may include concentrations of oil and grease, sulfates, total dissolved solids (TDS), and various additives that include toxic trace metal compounds. Reserve pits are potential sources of ground water contamination if the fluids are allowed to escape or migrate to the subsurface. This study does not include a comprehensive assessment of scientific literature documenting the relationship of oil and gas wastes and produced water to water quality contamination. A number of studies have been done in various states that indicate site-specific or aquifer-specific water contamination problems occur when reserve pits and produced water pits are not properly designed and/or reclaimed. The volume and quality of produced water, drill muds and other oil field waste, proximity and quality of surface and ground water, and characteristics of soil and underground strata, must all be taken into consideration in determining the potential for water contamination.

Wyoming is unique among the states in requiring a special application form for reserve pits, which includes a site map and plan, information about sub-soils, a surface water map, a chemical analysis of water at the site, a plan for final disposal of the mud, and a description of the sealing material that will used and how it will be installed. Following review of this data, the oil and gas agency may modify the plans on a case by case basis. As discussed above, North Dakota and Utah inspectors visit drilling sites before activity occurs, in part to determine reserve pit siting and construction requirements. In Utah reserve pits may not be sited on porous soils unless they are lined. In other areas, either tight soils must be present or the pits must be lined in a manner acceptable to the Board of Oil, Gas and Mining. Colorado and New Mexico have no specific pre-drilling information requirements or inspections for reserve pits. Both Colorado and Wyoming report that most of their drill muds are not salt-based. Alberta's reserve pit regulations are being revised. Current requirements provide that waste must be confined to the site and must be limited to 6,000 barrels unless a special application is filed and approved.

Montana has general rules for reserve pits that require construction to be "adequate to prevent undue harm to the soil or natural water." Also, "[W]hen a salt base mud system is used...., the reserve pit shall be sealed when necessary to prevent seepage." Inspections normally do not occur until after drilling has commenced. Soils data and and information about depth to water table are not included in the application nor is a minimum adequacy standard for construction or sealing defined.

Drilling site reclamation methods appear fairly consistent among the states (including Colorado and New Mexico), but methods of final disposal of the muds and fluids vary. It is important to note that pit reclamation is an essential component of the effort to control undesirable discharges or escape of fluids.

North Dakota and Wyoming regulations reference piling of topsoil during pit construction. Most states require that the surface be restored to as near original condition as possible, although landowner specifications must also be followed. In New Mexico, district oil and gas supervisors have authority to specify disposal and surface restoration methods, but contouring and re-seeding are not necessarily required. In Montana, previous productive capability must be restored. North Dakota requires reseeding with native species and restoration of the access road and pad unless the landowner specifies otherwise. North Dakota and Wyoming require reclamation to be complete within at least one year. The other states do not specify a time frame. North Dakota also requires a notice of intent to reclaim and verbal approval before the company proceeds.

In Colorado drilling muds are generally not considered toxic because they are primarily bentonite and water based. Such muds are commonly removed from the pits and discharged to the surface.

The Utah Health Department requires removal of reserve pit liquids and disposal in approved ponds. With approval from the department and landowner, surface disposal of the mud is also allowed. Alberta requirements are similar to Utah's.

According to Montana's rules, waste must either be removed or buried at the well site to a minimum depth of three feet below the restored surface of the land. Methods of disposal of muds/fluids removed from the site are not specified in the rules, but include discharge down hole, or hauling to another site re-use. Oil and gas agency staff request companies to obtain prior approval for down hole disposal. In some cases the liquid may be hauled away based on landowner specifications. In most cases the mud is left in the pit. Liquid that has not evaporated is drained off by squeezing and trenching the pit prior to leveling the site.

E. Interagency Water Quality Jurisdiction

In all of the states the health/water quality agency and the oil and gas agency have somewhat overlapping responsibility for water quality protection. Oil and gas agencies are usually responsible for on-site disposal in pits and UIC (except Montana), and health/water quality agencies are responsible for permitting surface discharges and off-site disposal in commercial pits.

All of the state oil and gas statutes convey authority to the oil and gas board or commission to require that drilling, casing, producing and plugging of wells be accomplished in a manner that prevents the pollution of fresh water supplies by oil, gas or salt water. On the other hand, the health/water quality agencies are given general responsibility for protecting the quality of all state waters. All of the states report some problems in smoothly regulating protection of water quality within the oil and gas industry.

Oil and gas agencies tend to emphasize production and conservation of the oil and gas resource and prevention of waste as their primary statutory responsibility. These agencies do not typically include environmental specialists on their staffs. The one exception of the states surveyed is New Mexico. An environmental unit has been formed within the oil and gas agency to oversee those portions of the regulations concerning water quality protection and to be the liaison to the environmental/water quality agency. Agency interaction undoubtedly is enhanced because the New Mexico Water Quality Control Commission has oversight responsibility for both the oil and gas agency and the environmental agency. A special memorandum delineates the agencies' respective duties and calls for close communication and cooperation where responsibility is unclear. In such instances the agencies are charged with reaching mutual agreement as to lead agency status and determining the method by which a water discharge plan will be evaluated.

In Montana, oil and gas wells are exempt from Groundwater Pollution Control System permitting requirements, but water quality agency staff become involved if a pollution event occurs or if complaints about water pollution are received. However, there is no interagency Memorandum of Understanding describing the areas of cooperation and areas of separate responsibilities between the two agencies. The situation in North Dakota is similar although health department personnel emphasize that they are routinely in close communication with the oil and gas agency.

In Wyoming reserve pits are explicitly exempt from the environmental quality agency's regulations, but produced water disposal is included. The Wyoming oil and gas agency appears to be taking lead responsibility for on-site disposal and the environmental agency for commercial disposal (see the next subsection). New Mexico and Colorado also follow this pattern, but as noted above New Mexico has worked out a unique cooperative system. Colorado's water and oil and gas agencies have also developed a Memorandum of Understanding that delineates their separate responsibilities.

The Utah oil and gas agency will soon be an exception to the pattern because it is in the process of taking over responsibility from the Health Department for regulating disposal of produced water in all types of pits. A Memorandum of Understanding has been drafted that declares it is the policy of both agencies to pursue a close cooperative working relationship. Also, the oil and gas agency has pledged its intent to "develop, administer and enforce regulations for design, construction, operation and abandonment of on-site and off-site disposal ponds and reserve pits that will be no less effective" than those the Health Department administered. Discussion of these regulations is included in the following subsection.

F. On-Site Produced Water Disposal in Earth Pits

Methods of produced water disposal vary considerably, based on the range of characteristics and existing uses of ground and surface water, chemistry of produced water, and soil characteristics. Underground injection and surface discharge disposal methods are regulated, respectively, under the National Pollution Discharge Elimination System (NPDES) and the UIC program. These methods are not examined in this study. In Montana these programs are administered by the Department of Health and Environmental Sciences and the U.S. Environmental Protection, respectively. Administration is relatively uniform among the various states. Although the NPDES establishes minimum standards for most discharges, including the oil and gas industry, states are given discretion to adopt more stringent standards.

North Dakota is not included in this comparison because surface pits have been prohibited for storage of salt water since 1968. Wyoming, New Mexico, Utah, Colorado and Alberta allow surface pits but require special applications, plans and permits for these facilities. These requirements appear to apply regardless of the type of produced water to be received, except that less stringent construction requirements (usually concerning the use of liners) may be imposed depending on the quality of the water. Some produced water in most states is of sufficient quality to qualify for surface discharge permits, and over the past few years, increasing volumes of produced water are being disposed by underground injection. However, if an operator wants to dispose of the water in earth pits the following types of requirements apply in the states listed.

Wyoming, New Mexico, Colorado, Utah and Alberta require similar types of information from companies wishing to construct water disposal pits, including anticipated volume and type of water to be received, soil and water data from the site, and plans for sealing or waterproofing the pit and final disposal of the water. Drawings and maps are also required. This information is evaluated to determine if the plans will adequately protect water quality and different design requirements may be imposed if necessary. New Mexico and Utah additionally require companies to submit descriptions of leak detection methods and leak prevention procedures.

New Mexico has adopted special orders concerning produced water disposal in each of its two producing basins, due in part to the high concentrations of TDS and also the presence of benzene in most of the water. In the northwest (the San Juan Basin), pits will be prohibited beginning January 1, 1987 in areas designated as having vulnerable aquifers. Operators of existing pits have to file registration forms. In the southeast, disposal in unlined pits is currently prohibited, and new lined pits are allowed only on leases where production is declining. New Mexico has issued detailed statewide guidelines for pit construction and design, liner installation, leak detection, and leak contingency plans.

When liners are required in Utah, at least two feet of impervious in-situ soils or placement of an equivalent amount of clay is necessary. Either method must meet an impermeability (seepage) standard of about one foot per year (10^{-6} centimeters per second). Artificial liners such as plastic or concrete may also be used. A monitoring system is required if the pit receives over 100 barrels per day, but this requirement is waived for artificially lined pits. Clay liners are the most common liner material in Alberta. The oil and gas agency staff report that artificial liners are not considered as effective.

New Mexico requires liners of at least 30 mills thickness and information on the resistivity of the material. Colorado requires liners and monitoring systems for facilities receiving over 100 barrels per day of water containing 5000 parts per million (ppm) TDS or greater. Liner requirements are determined on a case by case basis in both Wyoming and Colorado.

Wyoming, Colorado, Utah and New Mexico exempt pits receiving less than 5 barrels per day of water, although in New Mexico the water must have 10,000 ppm or less of TDS and the pit must be located at least 10 feet above the water table in order to qualify. Wyoming requires monthly monitoring and chemical analyses for exempt pits.

Montana's oil and gas rules do not require an application for or special information from applicants about plans to construct earthen pits. The regulations state that "[W]here the soil ...is porous and closely underlaid by a gravel or sand stratum, impounding of salt or brackish water in such earthen pits is prohibited." Pits that fail to properly impound such water can be condemned. "Salt or brackish water may be disposed ...in excavated earthen pits ...when the pit is underlaid by tight soil such as heavy clay or hardpan." In practice, oil and gas division staff report that there are relatively few water pits in long-term use. Those in areas of porous soils that contain salt water (primarily in the Williston Basin) must be impermeable (i.e., lined with synthetic material and/or bentonite) or they are subject to condemnation.

G. Safety

Safety regulations examined in this report include provisions for handling gas containing hydrogen sulfide (H_2S) and safety equipment requirements. Montana, North Dakota, and New Mexico have essentially similar requirements for flaring vented gas that contains H_2S, although Montana is the only state that links its requirement to a specific concentration (i.e., any vented gas containing 20 ppm or greater H_2S must be burned). North Dakota's air quality agency is considering a new rule that would require registration of all wells that produce H_2S-laden gas in order to review the control technology on these wells. Wyoming's air quality agency requires companies venting gas containing H_2S during well completion testing or workovers to file a notice. If the amount exceeds 50 tons/year of H_2S, a report is required that must state the reason for the flaring and discuss any efforts that were made to minimize the amount.

Utah and Alberta have special requirements for H_2S wells that include submission of plans for dealing with accidental releases and emergencies. In Utah the plans must be submitted with drilling permit applications for areas where H_2S is likely to be encountered or where its presence is unknown. The information must include plans for protecting workers and the public. A detection system capable of sensing 10 ppm H_2S and certain other safety equipment is required to be on site.

Since a major blowout that occurred in 1982 (the Lodge Pole blowout), Alberta has added a number of new regulatory and application information requirements to insure safety during drilling and production of sour gas wells. A classification system has been established for "critical sour wells" that is based on potential maximum H_2S release rates and such factors as population density, the environment, sensitivity of the area, and expected complexity of drilling the well. In addition to the types of information noted above for Utah, plans must be submitted that include: guarantees that adequately trained supervisors and a 5-person drill crew will be on-site; plans for blow-out prevention drills; the process for initiating emergency procedures; and evacuation plans for residents. Companies must identify an emergency zone wherein "worst case" H_2S concentrations could reach 100 ppm. Personal visits to all residents in the emergency zone must be made and input from other local residents solicited before the emergency plans are filed with the provincial government. Of 8,763 exploratory and development wells licensed in Alberta in 1985, 31 were classified as "critical"; emergency response plans were required for an additional 99 wells. Alberta government agencies have also prepared emergency response plans to coordinate the flow of information to and from the public and the media in the event that an H_2S emergency occurs.

All of the states and Alberta have requirements that blowout prevention and well control equipment must be adequate to keep a well under control, especially in unproven areas. Differences exist primarily in the specificity and level of detail of the requirements. Montana regulations require operators to "take all available precautions to prevent ...any well from blowing open." In unproven areas wells must "be equipped with a mastergate or its equivalent and an adequate blowout preventor, together with a choke and line or lines of the proper size and working pressures."

Wyoming includes a map in its regulations that shows where formation pressures are unknown. In those areas, types of required equipment, and installation, pressure and testing specifications are listed in detail. New Mexico requires a blow-out prevention program to be submitted with the drill permit application in areas of unknown pressure. Colorado lists equipment components, and requires daily inspections of equipment during drilling and posting of emergency phone numbers. Also, wells must be located at least 150 feet from buildings, roads and property lines.

Alberta has a well classification system based on depth. Detailed blowout prevention equipment and operational specifications are included in the regulations for each well class. Rig crews must be adequately trained and weekly safety drills are required. Also, testing requirements for each step of the drilling process are specified.

H. Air Quality

Sulfur dioxide (SO_2) and H_2S are the two primary air pollutants associated with oil and gas development. Flaring produces SO_2. As described in the section on safety, gas containing H_2S is supposed to be flared (unless it is collected and treated). If the equipment is working efficiently, the flaring completely converts the H_2S to SO_2.

All of the state regulations except Colorado's provide for flaring associated or "casinghead" gas, and flaring or venting of gas in connection with well completion and testing. Montana, New Mexico and Utah place limits on the time and/or volume of flaring that may take place. To exceed the rates set by Utah and Montana, operators must submit justification statements showing that marketing the gas is not economically feasible. North Dakota and Wyoming allow flaring pending arrangements to dispose of the gas in some useful manner. It should be noted that the oil and gas regulations in the various states approach flaring from the view point of conserving the gas resource and, where H2S-laden gas is concerned, to insure safety.

Air quality statutes and regulations require new sources of air pollutants to obtain a permit if they exceed a certain size as measured in emission levels. In Montana the emission standard is 25 tons or more of any regulated pollutant per year, including both SO_2 and H_2S. Past studies in Montana have shown that some wells exceed these limits but the violations are not usually discovered unless there is a complaint and subsequent monitoring.

Wyoming, North Dakota, Alberta and Montana air quality agencies have concerns about the cumulative impacts of flaring (i.e., a number of wells flaring in close proximity may result in violations of ambient SO_2 standards). Cumulative impacts have become an issue in Wyoming due to episodes of flaring large quantities of sour gas in the Overthrust area. However, no major studies have been undertaken to date. North Dakota reports that some areas producing gas with high H_2S concentrations are close to exceeding ambient SO_2 standards, again due to flaring. Monitoring stations have been established in Mackenzie County, in part because a Class I air quality area, the Theodore Roosevelt park, is located only a few miles away.

Several years ago an oil and gas well emission inventory was conducted in Montana's Williston Basin, but it produced inconclusive results because calculations were based on high, rather than average, H_2S concentrations. Stack tests of flare equipment have revealed inefficiencies in converting H_2S to SO_2 in both Montana and North Dakota. One problem noted by Montana air quality personnel is the lack of baseline data on existing ambient air concentrations in major oil and gas producing areas such as the Williston Basin. This makes it difficult to evaluate the effect of new wells.

Alberta's regulations require companies to file a special application in order to flare sour gas. The application must include a topographical map showing the well location and any towns, residences or recreation areas within a three mile radius, a gas analysis, the volume of gas to be flared and stack dimensions. Alberta has required operators to either gather the gas or cap wells in areas where the volume of flaring has threatened its air quality standards. Both Wyoming and Alberta officials report that sour gas processing facilities are a concern, especially if located near fields that are already near to or exceeding ambient SO_2 standards or, for Wyoming, if located near Class I air quality areas.

I. Well Abandonment

To abandon a well in Montana, companies are required to give oral notice and receive approval if no casing has been run. If casing has been run, written notice is required, including a description of the plugging method, and depths and number of plugs that will be used. The notice must also be sent to the surface owner. A subsequent report is required within 15 days that must specify the nature and quality of plugging materials used. The site is inspected thereafter. Release of the bond follows, typically after revegetation is established. Colorado has a similar system, except for requiring somewhat more detail in the completion report.

North Dakota, Utah and Wyoming regulations contain specific requirements for the length and placement of plugs. North Dakota and Utah also specify the amount and placement of cement. North Dakota is unique in requiring 24-hour advance notice of plugging; its policy is to have an inspector witness each plugging operation. Not enough details about Alberta's abandonment requirements were available to make a complete comparison with the various state regulations. Advance notice of plugging is required. However, plugging methods are not specified in the regulations and apparently are specified through interim directives from the provincial government.

Montana, North Dakota, New Mexico and Alberta have established "abandoned well" funds to provide for reclamation at wells that have been improperly plugged or well sites that have not been reclaimed. Alberta's program has only recently been created and is not yet fully operational. New Mexico oil and gas staff said that their fund is seldom used, and North Dakota reportedly spent only one-fifth of its available funds last biennium.

The history of Montana's program is similar to New Mexico's and North Dakota's. The abandoned well reclamation program was created in 1974 at the same time that the Resource Indemnity Trust (RIT) fund was established. The Department of Natural Resources and Conservation was given administrative responsibility for the program and instructed to maintain an inventory of abandoned oil and gas wells, injection wells, sumps and seismographic shot holes that "disturb land, water or wildlife resources to a degree not in compliance with plugging, pollution prevention and reclamation rules of the Board of Oil and Gas Conservation." The inventory is to be compiled from petitions or written statements from the owners of surface rights or lessees. If the responsible party cannot be located, the Board notifies DNRC, and the department is authorized to reclaim the disturbed land with RIT funds, as appropriated by the Legislature.

In each of FY's '82, '83 and '84, $65,000 was appropriated for the abandoned well fund. Only slightly more than $7,000 was spent on two or three surface restoration projects during that period. DNRC sent letters to a number of other state agencies requesting information about any problem wells that field staff might discover, but no additional projects were identified. During the 1985 legislative session the annual appropriation for the fund was reduced to $10,000.

II. SOME PREVIOUS OIL-GAS EVALUATIONS IN MONTANA

A. Environmental Quality Council

The Environmental Quality Council(EQC) has monitored activities of the Board of Oil and Gas Conservation and various environmental-related aspects of oil and gas production in the past. Previous activities have included a 1978 tour of areas in northeastern Montana where salt water brine contamination problems were occurring, and participation in meetings concerning gas flaring and methods of plugging seismic shot holes.

The 1978 tour and subsequent staff report appears to be the EQC's most extensive previous examination of environmental problems resulting from oil and gas production. The staff report stated that "the law governing the lining of salt water pits has been in effect since 1954, and yet we found instances of pits with no lining or pits lined with less than 2 inches of unpacked bentonite. ...We noticed salt water pits which were not sealed or had been sealed with 1 inch of bentonite." It was further noted that "a minimum of 6 inches of packed bentonite" is required for sewage lagoons by the Department of Health and Environmental Sciences, and that the Soil Conservation Service requires a minimum of 4 inches of packed bentonite for water up to 8 feet deep in its design criteria for dams and impoundments. If the water is deeper, the clay layer must be thicker.

The Board's current regulation concerning disposal of salt water in earthen pits was adopted in 1972. While the rule does not contain specific guidance about the amount of clay or other tight soil that is necessary to properly line a pit, it should be noted that the areas EQC observed in 1978 could have been contaminated by pits that were constructed prior to 1972.

The 1978 report concluded with a recommendation that the Board of Oil and Gas Conservation and other agencies cooperatively establish a sampling and/or ground water monitoring program to determine the extent of groundwater contamination problems from salt water and brines. This has not been done to date.

In October 1980, then EQC chairman Representative Dennis Nathe and EQC staff met with members of the Northeastern Montana Land and Mineral Owners Association, representatives of the oil industry and others to discuss salt water problems. One resulting recommendation was that "salt water pits shall be made impermeable or the material in question shall be stored in enclosed tanks. This requirement shall be placed on the drilling permit."

B. Legislative Auditor

In 1981 the Legislative Auditor conducted a sunset review of the Board of Oil and Gas Conservation. The auditor concluded that the Board has been less effective in protecting surface owner rights and other natural resources than in encouraging production. Recommendations to correct this problem included a number of items concerning management of the field inspection staff and the need for better inspection records. The Board took steps to address these recommendations by implementing a system for field inspectors to document their daily activity and authorizing compensatory time for inspectors so they can spend long hours in the field.

The auditor's report also included other findings concerning reserve pit regulations and the abandoned well reclamation program as follows:

1. "During drilling, the saltwater and mud are kept in (reserve) pits at the site. Board rules require that these pits be constructed so they are impermeable, but the rules do not further define impermeable. Most companies use plastic pit liners to assure proper containment. However, a few companies either do not use liners or use liners of such quality that they can be easily torn."

2. "Another practice of salt water disposal is the burying of contaminants on site. This seems inconsistent with having a pit liner since what was contained by the liner is now being introduced into the ground. The board could help alleviate these problems by revising its rules. It could consider rules to require pit liners for all salt-based drilling pits, to establish minimum pit liner standards, and to prescribe rules for the disposal of salt based residues."

3. "[T]here may be many improperly reclaimed wells drilled prior to the board's creation in 1954. ...The Legislature has recognized this potential problem and has defined a procedure to pay for the cleanup. Under the statutes, DNRC is to set up a procedure for cataloging reports of wells which were not plugged and abandoned properly. ...If the responsible party cannot be found or is no longer active, Resource Indemnity Trust money can be used to reclaim the site. The board has received an appropriation to fund reclamation from the Trust Fund. DNRC's approach has been to await reports of improper abandonments rather than actively soliciting them. Since DNRC has not received many such reports, there has been little activity relating to this statute. The Legislature should clarify whether it wants the board and DNRC to implement a program to actively solicit reports of improper abandonments."

C. Governor's Ground Water Advisory Council

In a January 1985 report, the Governor's Ground Water Advisory Council stated that monitoring near reserve pits is infrequent and that the number of contamination incidents reported in Montana may be small compared to actual contamination occurrences. The Council recommended that the Board of Oil and Gas Conservation assess the extent to which presently accepted reserve pit reclamation procedures threaten ground water quality. A June 1985 memorandum was written by oil and gas division's petroleum engineer in response to the Council's recommendations. It states that "[b]reaching the pit liner by squeezing and trenching the pit could result in the contamination of near surface groundwater in the vicinity of the pit," but most of this contamination would likely be limited to the vicinity of the site. In discussing potential changes in reclamation procedures to avoid potential contamination problems, the memorandum states that landowners and governmental agencies tend to specify that reserve pits must be reclaimed in the absolute minimum of time. As a result there may not be enough time for the fluids to evaporate.

According to the memorandum, the method of removing free water for off-site disposal, and allowing natural drying before backfilling the pit requires a much longer reclamation period. Alternatively, the pit contents can be removed off-site through the use of a closed mud system and reused at another site, but not all drilling contractors are equipped for this method of operation. If the mud cannot be reused, a disposal problem occurs due to lack of available sites. Local governments are not willing to accept the semi-liquid wastes at solid waste landfills, and commercial disposal wells cannot accept the mud solids. Therefore on-site burial of the mud solids continues to be the most viable disposal method.

The memorandum further notes that semi-encapsulation of the mud pit appears to be a reasonable alternative in cases where adverse affects to groundwater are likely. Trenching and spreading the mud solids can be avoided by folding the pit liner over the pit, with care not to tear the liner. Additional dewatering would be necessary, and possibly a longer period for drying of the pit contents. However, in this manner the integrity of the liner could be better maintained. Additional liner material could be placed over the pit if folding the existing liner over the pit cannot be done; a bentonite seal could also be acceptable.

The memorandum concludes that prohibition of squeezing and trenching reserve pits on a statewide basis would probably be both unreasonable and a burden because groundwater quality is not likely to be adversely affected. However, "[i]n cases where pit contents pose a threat to water quality some additional care and expense may be fully justified."

III. REGULATORY ANALYSIS AND OPTIONS

A. Introduction

The review presented in Part I indicates the variety of approaches utilized in state and provincial oil and gas regulation. Some agencies require a great deal of specific information for permitting decisions, while others grant routine approvals with little paperwork or preliminary inspections. Even within a single jurisdiction, regulatory constraints may vary widely depending on the phase of exploration or development under review.

Environmental protection objectives of all types are often better achieved though preventive actions rather than through penalties, condemnation and/or clean-up efforts after water contamination or other problems have already occurred. Also, reactive efforts can be more expensive and are less effective than designing projects with appropriate environmental safeguards built in from the beginning.

In order to analyze the effectiveness of the various regulatory systems, it is important to keep in mind the goals of oil and gas regulation that are associated with environmental protection. The following discussion lists the environmental regulatory goals of various phases of oil and gas development, including seismic exploration, drilling permits, reserve pits and produced water pits, and safety considerations. The highlights of the regulatory systems imposed by other jurisdictions are then compared to the Montana system. Abandoned well reclamation and staff resources are also discussed. Finally, options for Montana regulation are sequentially presented and numbered within the following subsections, and information presented on the tradeoffs that adoption of these options might entail. A number of the options follow up on the recommendations resulting from previous evaluations discussed in Part II.

B. <u>Seismic Exploration</u>

<u>Environmental Regulatory Goals</u>:

1. Provide advance notice of seismic operations to surface owners and the state to provide opportunity for interaction and ensuring that concerns are addressed

2. Require adequate shothole plugging to protect water quality and ensure public safety

<u>Comparative Analysis</u>

Contact between seismic exploration companies and Montana oil and gas division staff does not typically occur before field operations commence, except through telephone conversations. The counties call the oil and gas division concerning pending exploration activity when the exploration permit has been issued. Division staff then have an opportunity to discuss the planned operations with the seismic crew.

Landowners in Montana have apparently had more complaints about improper plugging of shotholes in the past than in recent years, probably due to statutory changes and new or amended regulations that were adopted in 1977, 1982 and 1983 to require seismic crews to provide proper identification and advance notice of planned operations to surface users. The various states and Alberta exhibit a wide range of inspection patterns. Utah and Alberta inspectors try to observe seismic shothole operations. North Dakota does not make seismic-related inspections of any type. Montana and Colorado inspections occur after plugging is completed, but the inspectors do not visit all shotholes.

The system used in Wyoming varies from these approaches. Wyoming oil and gas staff meet with seismic exploration companies before they begin initial operations in the state. This meeting is to ensure that the regulations are discussed and it removes the problem of trying to have such conversations at a point when specific individual field operations have been permitted and may be about to begin.

<u>Options and Tradeoffs</u>

1. Montana's Oil and Gas Conservation Division staff could hold meetings with seismic crews before they begin initial operations in the state.

This option would add to the staff work load, but it could result in a reduction of time required for separate telephone discussions prior to each individual seismic operation.

2. Oil and Gas Conservation Division staff could inspect all or a greater proportion of plugged seismic shotholes than is done under current practice.

The tradeoff is between work load level, work priorities other than seismic operations, and water quality protection. Since the current volume of oil field activity is drastically lower than previous years, more staff time might be available to inspect shothole locations.

3. A reporting system could be developed to require seismic exploration companies to file information indicating whether water was discovered in any of their shotholes, and if so, what type (i.e., artesian, non-artesian, salt, fresh).

This option would allow plugging inspections to be targeted to those holes that would involve the highest risk of creating problems if not properly plugged.

4. The current practice of discussing individual seismic operations with companies by telephone, and inspecting a random sample of plugged holes could be continued.

Staff work load may be greater than would be required by a system of having one-time meetings with seismic companies before they begin to operate in Montana. Random inspections of a portion of shotholes may mean that some improperly plugged holes are overlooked, with attendant problems unresolved.

C. Drilling Permits

Environmental Regulatory Goals

1. Ensure proper well construction for safety and water quality protection

2. Require wells and other surface facilities to be constructed, and associated surface uses to be conducted, in an environmentally acceptable manner

Comparative Analysis

Personnel from several other state and Alberta oil and gas agencies indicate that they have authority to attach stipulations to permits addressing pit siting and construction, safety, surface use, road placement and any other practices associated with oil and gas development that can adversely affect the environment. The other states' statutes do not appear to be significantly different than Montana's, but additional legal evaluation is needed to determine this with any certainty.

Montana's Board of Oil and Gas Conservation considers issuance of drilling permits a ministerial action*. The Board places standard conditions on all drill permits that address such matters as permit fees and bonds, construction of an "adequate" sump to contain all mud and water bailed from the hole, and properly cemented casing both to control the well and to protect possible productive and fresh water formations. The Board's staff also have occasionally required more surface casing than included in an operator's original drill plan in order to protect fresh water aquifers.

The Board believes it lacks authority to condition permits to lessen the potential environmental impacts associated with surface activities such as road building and placement of pits (see EQC Staff Report, "Montana Environmental Policy Act (MEPA) Review of Oil and Gas Drilling Permits"). The Board's regulations do not provide for the collection of site data that would allow the staff to identify and correct potential environmental problems before they occur. If the operator makes a wrong decision, the available options include withholding all or part of a company's bond, potential condemnation of pits and potential legal action by the surface owner. Montana's statutes and regulatory system defer to the surface owner's judgement in a variety of instances (e.g., seismic shot hole plugging, stipulations placed on surface use and restoration). In the case of shot hole plugging, the oil and gas rules contain plugging specifications, but landowners may agree to different methods. The Board has statutory authority to adopt rules to prevent contamination of and damages to surrounding land or underground strata caused by drilling operations and production, but there is no reference to surface use restrictions.

In 1981 the oil and gas statute was amended to require oil companies to notify landowners before drill operations begin, and to provide for landowner collection of payments for surface damages or disruption. Testimony presented in support of this legislation by landowners from major oil and gas producing areas in Montana included cases where landowners were given little or no notice of pending drilling operations, and were not included in well site or road selection.

*A ministerial action is a decision that an agency carries out according to predetermined criteria (i.e., determining that permit fees have been paid, and descriptive information about the proposed well drilling program has been submitted). No judgement is necessary in carrying out a ministerial action if all the criteria are met. By contrast, a discretionary action involves analysis and potential modification of proposed drill operations to account for site-specific differences in both surface characteristics and underground strata.

According to the testimony, damages from improperly constructed or improperly reclaimed reserve pits, improper surface restoration, and road placement and construction have occurred. Many of these problems apparently occurred in cases where mineral and surface ownership are split. Cases of misunderstandings were reported about the timing and amount of clean-up and surface restoration a landowner could expect.

Many of the problems arising from lack of landowner notification prior to drilling have ceased. However, there may be a continuing correlation between the types of problems cited by the landowners and the lack of clear requirements in the Board's rules and/or the lack of regulatory involvement in road and pit placement and construction, and other surface use activities.

Most state oil and gas laws reflect the concept that landowners should have a decisive role in determining how oil and gas operations are conducted on their property and ensuring that land and water protection measures are fully integrated into the specifications that oil and gas companies are expected to follow. Utah's system of scheduling pre-drill site inspections, which are attended by state agency personnel, company representatives, and the landowner(s), appears particularly conducive to determining the most acceptable means of proceeding with oil and gas development activities with all parties involved. Considering the diversity of industry practices and variety of soil, water, underground strata and surface characteristics that exist, it is impossible to specify requirements in rules that would appropriately address all site situations. Evaluation of individual site circumstances is more effective.

<u>Options and Tradeoffs</u>

5. <u>Additional legal review could be requested to clarify the extent of the Board's authority to condition drill permits for purposes of environmental protection. Based on the results of the review, additional legislation or rulemaking could be considered, if necessary, to ensure that water quality and other environmental values are protected</u>.

6. <u>The Oil and Gas Conservation Division's review of drilling permits could be modified to include conference calls between the staff, company representatives and landowners. In complex cases, the review could also include pre-drill site inspections. Both conference calls and pre-drill site inspections could be used to determine appropriate environmental stipulations to attach to the drill permit</u>.

This option would add some time to permit review, but would provide the benefit of increased communication among the involved parties and increase environmental protection.

7. <u>The Board's rules could be modified to require companies to submit drill site maps and plans, soil and water data, and site reclamation plans with drill applications</u>.

Environmental review of this material would add to the staff's work load and increase the developer's pre-drilling costs. However, options discussed more fully in another EQC staff report concerning the applicability of MEPA to drill permits indicate that most applications could still be processed expeditiously.

8. The current rules and regulatory system could be maintained.

Some environmental impacts would not be avoided; staff work load and industry responsibilities would not be increased.

D. Reserve and Salt Water Disposal Pits

Environmental Regulatory Goals

1. Protect water quality

2. Restore surface values

Comparative Analysis:

States regulate construction of reserve pits and produced water pits to protect surface waters and shallow groundwater during and after drilling. Wyoming has the most comprehensive regulatory system for reserve pits, requiring companies to gather and submit site-specific water and soil data and pit design information before drilling and pit construction is begun. This system allows the agency to evaluate plans and determine whether any modification is necessary.

Another approach, used by North Dakota and Utah, features drill-site inspections before work commences in order to assess site conditions and insure that reserve pit siting and construction plans are appropriate.

Montana's approach to reserve pit regulation relies on broad statutory language and rules which state that construction must be "adequate" and sealing is required "when necessary" to prevent seepage. Site inspections usually do not occur until after drilling has commenced.

Alberta and all of the states except Montana (and North Dakota, which prohibits salt water pits) require applications and site-specific data before approving construction of on-site produced water disposal pits. These requirements appear to apply to all types of produced water. Utah and New Mexico provide minimum permeability specifications and construction guidelines for installation of pit liners. Monitoring is also required in some cases.

Again, Montana relies on general rule language. Regulations prohibit on-site disposal of produced salt water unless "tight soil" is present. No guidance concerning proper construction of pits is provided and no standards are specified for minimum leakage. Pits that fail to properly impound salt or brackish water may be condemned.

Reclamation of pits involves both surface activities to restore land uses and final disposal of drilling muds and produced water to protect water quality. As noted previously, drilling site reclamation methods appear fairly consistent among the states, and landowners are often given discretion to specify final surface restoration.

Requirements for ultimate disposal of pit muds, drill fluids, and produced water vary widely. A number of methods for pit reclamation are available, and no single method is necessarily appropriate for all locations or conditions. Surface disposal of pit muds is allowed in some states without review. Wyoming requires companies to file a plan for final disposal of reserve pit contents. Alberta and Utah require disposal at approved, off-site facilities unless special permission is given for another disposal method. The Montana oil and gas regulations do not require companies to submit plans for final disposal of drill muds, fluids and produced water, so there is not an opportunity to review proposed drill operations on a case by case basis. According to the Board's rules, waste in reserve pits must either be removed or buried at least three feet below the restored land surface. In a majority of cases, the mud is left in the pit, and liquid that has not evaporated is drained off by trenching prior to leveling the site.

Past evaluations in Montana relating to oil and gas field waste and produced water have included recommendations stating that some type of monitoring program should be established to determine the extent of ground water contamination that may be occurring. To date, no program has been established and very little information specific to Montana has been collected. It has been generally assumed that problems are limited to the localized area around individual well or pit sites, and that contamination of a few acres or nearby water wells is the full extent of the problem. Research on effective pit sealing technologies has largely been confined to the private sector.

Options and Tradeoffs

9. The Board's rules could be modified to require submission of plans for pit construction (in conjunction with site specific soil and water data as specified in Option 7). Staff would review the appropriateness of the plans for each proposed drill location.

10. Pre-drill inspections and inspections before produced water pit construction could be done in lieu of Option 9.

Both Options 9 and 10 would enhance water quality protection efforts. Both options would also require extra staff time. Option 9 would involve review of additional information that is not presently included in permit applications. Also, companies would incur additional expense in collecting the information, but the cost would be similar to costs incurred in surrounding states for comparable requirements.

Inspection staff currently visit sites at some point during drilling operations. If Option 10 were implemented this would add an inspection that does not presently occur, but the visit would be used to insure that drilling and associated activities are appropriate to the site.

Option 9 would allow the staff to conduct a desk review and convey comments to applicants via the telephone. By comparison, it might not always be possible to make site visits in time to accomplish the intent of Option 10 without causing delay of drill operations. Also, Option 9 has the advantage of causing the site data and construction plans to be documented. The Board could waive the need to re-submit the site information for subsequent drill operations on or next to a location previously documented, if soil and water characteristics are the same. After initial implementation, the main burden of gathering site data would fall on wildcat operations.

11. The Board's rules could be modified to:

a. specify a minimum leakage or permeability standard for earthen pits;

b. require submission of plans for disposal of drill fluids and/or produced water, including chemical analysis of these waste liquids. The Board's staff could subsequently modify the plans, if necessary, through conditions on the drill permit.

Industry representatives have frequently expressed the importance of clear regulatory requirements, both through written rules and discussions with agency personnel early in project design. Option 11 would provide a definition of the quality of pit construction that operators need to meet in order to "adequately" seal a pit.

Option 11 would require additional staff time to review plans for ultimate disposal of waste material and fluids and to ensure that the plans are appropriate to the site. Plan preparation would require additional cost and time and, in some cases, additional cost for pit construction and waste disposal. The benefit would be decreased incidents of water contamination due to inappropriate pit construction and reclamation.

12. Retain Montana's current rules and regulatory practices.

Montana's rules and current regulatory practices do not include the guidance or documentation requirements of Options 9, 10 and 11. If pits are improperly constructed, the only recourse is condemnation and cleanup efforts.

13. The Board of Oil and Gas Conservation, the Water Quality Bureau, and any other interested agencies could establish a task force to develop siting criteria for reserve and process water disposal pits and to identify ways to establish a program for monitoring ground water around pits and abandoned well sites.

a. An interagency proposal could be developed to establish a monitoring program with RIT funds.

The tradeoff of not making the effort described in Option 13 would continue the current lack of understanding of the magnitude of water contamination problems from oil and gas operations.

E. Water Quality Jurisdiction

Environmental Regulatory Goal

1. Improve effectiveness and efficiency of water quality protection efforts

Comparative Analysis

According to water quality and health agency personnel in all of the states surveyed, the split in responsibility for water quality between health and oil and gas agencies, along with the lack of environmental staff within oil and gas agencies is a common problem that is hampering water quality protection efforts. Some states have devoted significant effort to coordinating the efforts of their oil and gas and water quality agencies, including New Mexico and Utah.

Options and Tradeoffs

14. The Board of Oil and Gas Conservation and the Water Quality Bureau could be requested to more closely coordinate their efforts and improve communication, potentially including:

a. forming an on-going task force that would meet periodically to discuss problem areas of common interest and responsibility in protecting water quality;

b. formulating a Memorandum of Understanding delineating areas of separate responsibility, and areas where consultation and cooperation would be routinely sought;

c. identifying ways for field inspection personnel from both agencies to cooperate more closely in reporting incidents/sites observed in the field that may be creating or have the potential to create water contamination problems;

15. Although the addition of environmental staff to the oil and gas division may be unlikely in the near term considering the current budget deficit and the depressed state of the oil and gas industry, such an option could be considered for the long term, potentially to be patterned after New Mexico's approach.

16. Current regulatory practices and interagency communication patterns could be maintained.

Monana's water quality and oil and gas agency personnel currently work together primarily when a pollution incident has occurred. Some additional staff time would be required to achieve closer coordination and communication. The benefit might be increased ability to prevent pollution events from occurring or escalating. Given that the Board has primary oversight of all aspects of oil and gas field operations, water quality protection efforts might be most enhanced by addition of at least one environmental specialist to the oil and gas agency staff.

F. Safety

Regulatory Goal

1. Ensure public safety through well control and, where necessary, special management procedures for wells that may produce H_2S gas.

Comparative Analysis

Safety in oil and gas drilling operations is particularly important when there is a potential for discovering H_2S gas. Alberta has a system of classifying "critical sour wells" in terms of both potential H_2S release rates and proximity to people. Both Alberta and Utah require companies to submit plans for dealing with emergencies and accidental releases of H_2S, including plans for protecting workers and the public. Montana's rules do not contain this type of requirement.

Options and Tradeoffs

17. The Board's rules could be modified to require submission of emergency response plans in the event of an accidental release of H_2S.

a. A map showing areas where this rule would apply, or a classification system based on potential H_2S release rates and proximity to residential areas could be developed to better limit the requirement in Option 17 to certain geographic areas or types of wells.

18. A model emergency response plan could be formulated by a task force composed of oil and gas agency staff, oil industry representatives, and interested citizens. This plan could be attached as a condition to drill permits for operations in areas where the potential for discovering H_2S exists.

19. Retain the current rules, which mention H_2S only in the context of requiring flaring of vented gas containing 20 parts per million or greater H_2S.

Preparation of emergency response plans would be an additional information requirement for companies proposing to drill wells in areas where discovery of H_2S gas is likely, or where its presence is unknown. Proximity of proposed drill sites to residential areas has caused public concern in one case in Montana, Sohio's Bridger Canyon drill operation. The potential for an H_2S accident or emergency is very remote if proper well control technology and procedures are used. Nevertheless if an emergency situation were to occur, it would be very important to have plans in place that would insure an immediate and proper response by the drill crew.

G. Abandoned Well Reclamation

Environmental Regulatory Goal

1. Surface restoration and water quality enhancement through clean-up of improperly abandoned wells and sites.

Analysis

During the 1985 legislative session, the Board of Oil and Gas Conservation proposed the establishment of a $1,000,000 contingency fund to respond to problems created by improperly abandoned well sites. Also, an annual budget of $100,000 was requested for this purpose. The proposal was rejected. The abandoned well reclamation fund has a $10,000 appropriation from the RIT fund for FY's 86 and 87. Very few reclamation projects were funded in the period from 1982-1984. However, in 1985 the Board of Oil and Gas Conservation was informed that a leaking well in Liberty County had damaged 1½ acres of farmland and that the current leaseholder's attempts to plug the well had failed. A minimum of $55,000 is estimated to be required to properly reclaim the well. Due to the reduced appropriation, this amount is no longer available. Although about three-quarters of the RIT is funded by oil and gas industry taxes, the reduced appropriation apparently reflects the lack of reclamation projects funded in the past.

Options and Tradeoffs

20. The Board could request its staff to make a report to the 1987 Legislature about the volume of leaking wells or other reclamation problems that are known, discovered or anticipated through the rest of 1986. The report could also include remedial action priorities.

21. Depending on the number of potential projects, the funding level for abandoned well and related surface reclamation could be re-examined during the 1987 legislative session.

The 1981 Legislative Auditor's sunset review concluded that the legislature should clarify whether it wants the Board and DNRC to actively solicit reports of improper abandonments. Currently problem well sites are identified based on landowner complaints, although inspectors also watch for such sites on a continuing basis. A re-newed effort to collect and categorize abandoned well sites that may qualify for reclamation would help establish the volume and extent of the problems the abandoned well fund was established to address. If the list of sites were compiled based on inspector observations, in addition to those specifically reported by landowners, this would take some additional staff time but might yield a more accurate inventory of problem wells.

H. Staff Resources

Environmental Regulatory Goal

1. To ensure adequate guidance to companies concerning environmental regulatory requirements and to provide adequate enforcement.

Comparative Analysis

Based on 1984 data concerning the size of the oil and gas industry and size of field inspection staff in the various Rocky Mountain states and Alberta, Montana's inspector work load appears to be in the middle range when compared to the inspector work loads in the other states/Alberta. Utah, Alberta, and North Dakota inspector work loads appeared to be roughly half that of Montana's, although the North Dakota and Alberta inspectors have Underground Injection Control program duties that were not factored into the work load calculations.

The work load levels calculated in this study do not account for the many variances in regulatory patterns among the states. Another problem is the difficulty of determining the relationship between the quality of environmental-related oil and gas regulation and enforcement among the states and Alberta based on this type of comparative work load data.

Utah appears to have a generally strong environmental component in most of the regulatory categories examined, and it also has one of the lowest inspector work loads. This could imply that Utah inspectors have more time to ensure the quality of individual drill and production operations. The work loads of New Mexico, Colorado and Wyoming inspectors are over twice as high as Montana's, but for selected areas of regulation these states appear to have regulatory systems that achieve a somewhat greater level of environmental protection than Montana rules and regulatory practices (e.g., reserve pits in Wyoming, and produced water disposal in all three states).

Options and Tradeoffs

22. An analysis of the effect of any changes in rules or regulatory practices on Oil and Gas Conservation Division staff could be made in conjunction with efforts to implement options for change previously discussed in this report.

a. The Board and Oil and Gas Conservation Divison staff could be requested to formulate specific proposals to address the potential changes included in the options previously presented in this report.

b. Recommendations and alternative options for re-structuring staff work loads, and/or adding staff, could be developed as a result of the analysis.

The need for this option appears evident in the context of any significant change in an agency's mode of regulation. A long-term and short-term administrative plan would likely be needed to implement options that could result in new rules, staff review of more detailed drill applications and/or additional drill site inspections. This may be an appropriate time to consider changes, given the current hiatus in drilling activity and production.

APPENDIX A

ADMINISTRATION	MONTANA	NORTH DAKOTA	WYOMING	UTAH	COLORADO	NEW MEXICO	ALBERTA
Primary Regulatory Authority	Board of Oil & Gas Conservation	North Dakota Industrial Commission	Oil & Gas Conservation Commission	Board of Oil, Gas & Mining	Oil & Gas Conservation Commission	Oil Conservation Commission	Energy Resources Conservation Board
Ratio of Total Counties to O/G Counties [1]	56:32	53:17	23:20	29:12	63:31	32:9	Not Available
Total Operating Wells-1984 [1] (Oil/Gas)	6,674 (4,716/1,958)	3,494 (3,404/90)	13,494 (11,561/1,933)	2,458 (1,799/659)	9,023 (5,360/3,663)	34,547 [5] (18,146/16,401)	41,500 [6] (18,000/23,500 [6]
Total Wells Drilled-1984 [1] (Oil/Gas/dry/service)	725 [2] (350/101/272/2)	634 (341/3/290/0)	1,494 (688/118/655/33)	424 (222/77/125/0)	1,573 (579/438/555/1)	1,501 (898/413/250/40)	1,975 [6] (550/375/1050 [6]
FY 1984 Budget	$977,304	$ 1,489,000	$1,145,000	$1,431,000	$1,024,000	$2,376,000	$36,200,000 [6]
Includes Underground Injection Control(UIC)	No	Yes	Yes	Yes	Yes	Yes	Yes
# Field Inspection Staff	7	13	6 [3]	7 [3]	5	15	107

[1] Source: Petroleum Independent, Sept. 1985
[2] 781 (Maio, '85)
[3] Wyoming and Utah field staff totals do not include UIC staff. In the other states with an UIC program and Alberta, the field inspection staff also performs UIC duties.
[4] In some states, water quality protection responsibilities are shared with a separate environmental or public health agency (see discussion on process water disposal).
[5] According to New Mexico's Oil Conservation staff, 25,000 oil wells and over 17,000 gas wells (Boyer, '85)
[6] Field staff is 1985 total. The budget includes a small amount of coal and hydro expenditures, but is primarily (93%) oil and gas related. All data is taken from Energy Alberta 1985.

SEISMIC EXPLORATION	MONTANA	NORTH DAKOTA	WYOMING
PERMITS	Yes. Counties issue permits for geophysical activity. Notice of intent must be filed with the county and the Oil/Gas Division. Also, companies must notify the surface user and provide a description of the surface area involved and any needs for water.	Yes. Counties issue. Notice of intention for geophysical activity including names and addresses, date, location and estimated depth of any drill holes must be filed with the county. County may add conditions or restrictions by ordinance. Commissioners must forward notice to the state Industrial Commission. "Operator" of the land must be notified 3 days prior to tests.	Yes, state issues. Notice of intent required, including dates, approximate number, depth and location of holes, contact persons, and detailed description of hole plugging procedures. For surface shoots, residents within one mile must be informed.
BONDING	Surety bond of $10,000 for a single crew or a blanket bond of $25,000.	Surety bond of $15,000 for a single crew or blanket bond of $30,000.	Plugging companies, $10,000; geophysical contractor, $50,000, although the supervisor may waive or modify based on anticipated amount of damage.
INSPECTIONS	Not normally done during the operations. A representative sample of shot holes inspected after plugging is completed.	No inspections of any type.	Unless waived by state supervisor, companies planning to conduct seismic shot hole operations are required to meet with oil/gas staff prior to beginning operations in the state.
ADVANCE NOTICE OF PLUGGING	Advance written notice to the Board is required, including date, time, place, and name of contact person. A copy must be sent to the surface owner at the same time. Within 3 months after the work is completed, the company must file a record of the township & range & date that any shot points were fired. If a landowner complains, locations within a 4-section area of land must be specified.	Yes. 24 hours (to county commission) including location contact person, date and time. Copy to be sent to landowner or lessee. Written notice required upon completion. Within 30 days after plugging, companies must file record with the county & landowner showing location by township and range and date work was commenced. Landowner may request a legal site description in conjunction with a damage complaint.	Yes, 24 hours. Also, reports required at 30 day intervals or 30 days after completion including location of holes on USGS maps accurate to within 2000' - 4000' and statement that all work was done in accordance with the rules. These reports are kept confidential for 5 years.

SEISMIC EXPLORATION	UTAH	COLORADO	ALBERTA
PERMITS	Yes, state issues. Filing of a notice of intent to conduct seismic exploration is required 7 days in advance. Also, a permit to drill shot holes must be obtained 7 days in advance. Application must include detailed description of plugging procedure, contact persons, locations. Oral approval to proceed may be given.	Yes, counties issue. Seven day advance notice of operations is required, including method of exploration, a map showing proposed seismic lines, and names of contact persons. If shot holes are required, a map at least ½" to the mile in scale, number and approximate depth of holes, size of charge, and description of plugging procedures must be included.	Yes. Also, "exploration restricted" areas are identified on maps included in the regulations. These primarily include environmentally sensitive areas on public lands. Also, sites located within city or town limits or other areas within an agency's specific jurisdiction must receive their approval in addition to the exploration permit. Advance written notice of the location and time of operations is required.
BONDING	No	$5,000 per operation up to 100 holes or $25,000 blanket bond.	Security deposits may be required on a case by case basis, by the Minister of Energy and Natural Resources, especially for exploration in restricted areas.
INSPECTIONS	Sites are usually visited during the operation.	No site inspection occurs until after plugging is complete.	Inspectors are present when seismic shots are made.
ADVANCE NOTICE OF PLUGGING	Yes, 24 hours. Final report required within 60 days after project completion certifying that plugging requirements have been met, and including a map of the shot points accurate to within 2000'.	No advance notice. However, a completion report is required in 60 days including a map certifying that plugging is in compliance, specification of plugging material and procedures, and identifying any water that was discovered.	No advance notice. A completion report is required within 60 days, including a map of the area, identifying roads used and showing each shot hole location.

SEISMIC EXPLORATION	MONTANA	NORTH DAKOTA	WYOMING
PLUGGING REQUIREMENTS	Unless otherwise agreed to between the surface owner and the company, the following requirements apply: No hole may remain unplugged over 30 days, but the Board or staff may extend up to 90 days. If there is no artesian water, a bentonite-water slurry with Marsh funnel viscosity of 60 seconds or greater per quart is required for plugging. Minimum bentonite concentration specified. If artesian water is present, a cement slurry is required. The surface area must be restored to original condition insofar as practicable & appropriate seeds planted. Note: The Board is evaluating potential changes in the regulations to specify plugging with coarse ground bentonite (minimum of 100 #) where non-artesian water is encountered. Air-drilled and completely dry holes would be plugged with bentonite/water slurry or 50# coarse ground bentonite. Shot holes would be pre-plugged before shooting.	Holes may not remain unplugged over 30 days, but the county commissioners may extend up to 90 days. Preplugging required for seismic holes, amount and specs of bentonite specified. Bentonite-water slurry same as Montana requirements. If artesian water, cement or sodium bentonite chunks required. Stabilization must occur in reasonable length of time. If alkaline or saline artesian water, plugging with heavier slurry and drying or stabilizing chemicals is required immediately. Surface must be restored to original condition insofar as practicable. All debris must be removed.	For non-artesian water, bentonite/water slurry, including viscosity and density specifications. For air drilling, slurry or coarse ground/bentonite is acceptable (assumes non-artesian water). For dry holes that are air drilled, cuttings may be returned to the hole. If there is artesian flow, cement is required. No holes to be left unplugged after 30 days, without approval. Surface restoration is to be accomplished by raking the cuttings so plant growth will not be impaired.

SEISMIC EXPLORATION	UTAH	COLORADO	ALBERTA
PLUGGING REQUIREMENTS	Unless an equivalently suitable material is approved, a water bentonite slurry is required if non-artesian water encountered. Cuttings may be added. Viscosity same as Montana. For air drilled holes, cuttings can be used to plug. Cement required if artesian water. No holes may be left unplugged for more than 30 days without approval. Surface area must be reclaimed and reseeded to original condition insofar as practical and as required by the Board. Note: Upon application, approval may be given for pre-plugging with coarse ground bentonite (of specified size and quality). Sales receipt may be required.	Unless the operator can prove another method is adequate to protect ground water and provide stability, the plugging procedure requires use of coarse bentonite to at least 10 feet above non-artesian water, with a permaplug set 3 feet below ground. If artesian flow, coarse sodium-bentonite or cement must be placed at least 50 feet above. If no sub-surface water, cuttings may be returned to the hole. Surface must be raked and cleared of debris. No fired hole may remain unplugged for more than 30 days without approval.	Plugging requirements in the regulations are general. If water or gas comes to the surface of a hole, it must be plugged without undue delay and notice given. Holes that have not been permanently abandoned must have a plug placed 45 centimeters below the surface and be filled from the plug to the surface if the hole is left unattended. Permanent abandonment instructions are issued by the Minister of Energy & Natural Resources.

ABANDONMENT	COLORADO	NEW MEXICO	ALBERTA
Well Plugging	Plugging method must permanently prevent migration of oil, gas and water. Refers to dry or abandoned wells, and seismic, core or other exploratory holes. Approval of the plugging method must be obtained prior to plugging and notice given of estimated time and day.	Notice of intent required, including detailed statement of work (e.g., plans for shooting, pulling casing, mudding, cementing, depth of plugs).	48 hour notice of intent to plug required. Plugging requirements not specified in the materials and regulations available for this study except that a cement plug must be extended from a depth of at least 200 meters up to the surface, unless that interval is covered by casing which is cemented.
Subsequent Reports/ Inspections	A subsequent report is required within 30 days that must include a statement of nature of material, extent and depth of plugs, amount, size and location of casing left in the well, and volume and weight of muds. Inspections occur after abandonment.	The well owner must contact the Oil and Gas Division to arrange for inspection within a few weeks after abandonment. Report must be filed within 30 days, including information about the nature and quantity of materials used.	Companies notify the area office after reclamation and abandonment is completed. If the site is satisfactory a certificate of compliance is issued.
Bond Release	Bonds are not released until after abandonment approved.	Bonds are released after inspection and approval.	No bonds are required.
Abandoned Well Clean-up Program	No	Yes. There are statutory provisions to survey wells and prepare cleanup plans, but this occurs only if an inspector happens to discover a problem.	Yes. A program has recently been created, but has not yet become fully operational. Improperly plugged wells appear to be the main type of project that the fund will be used to clean-up or correct.

ABANDONMENT	MONTANA	NORTH DAKOTA	WYOMING	UTAH
Well Plugging	If no casing has been run, oral notice and prior approval required. If casing has been run, written notice required, including method, depths and number of plugs. Plug specifications not included in the regulation. Notice must be sent to Petroleum Engineer and to surface owner.	Notice of intent, detailed statement of work, and prior approval of plugging method required. 24 hour advance notice required for plugging operation. Test wells that have not had production casing in the hole may be plugged with verbal approval. Number of sacks of cement and placement of cement and plugs are specified when approval to plug is given.	Notice of intent and prior approval of method required (applies to any well, stratigraphic test hole, core hole, dry hole or other exploratory hole). Notice must include detailed statement of work (mudding, shooting, cementing, testing and removing casing; type, location and kind of plugs). Specific requirements included for length and placement of plugs, especially over porous formations.	Notice of intent is required and statement of method to be used, including a description of well base configuration and tops of known geologic markers. No specific requirements are included on length and placement of plugs and amounts and placement of cement. Alternate methods require special approval. Verbal approval may be given in emergencies.
Subsequent Reports/ Inspections	After plugging, a subsequent report is required within 15 days, including nature and quantity of materials. Site visits occur after restoration and plugging complete. Verification of the amount of cement used may be required.	The policy is to have an inspector witness every plugging. Subsequent report required within 30 days; and if requested, a copy of the cement receipt and detailed description of the plugging method.	Final site inspection triggered by subsequent completion report which must be submitted within 30 days including a detailed account of the work, weight of mud, location and extent of plugs and of casing. Cementing invoices must be preserved for one year. Supervisor may request a copy.	Inspections either occur during the plugging operation or shortly thereafter. Subsequent abandonment report required within 30 days. Requires detailed statement of nature and quantities of materials used.
Bond Release	Bond release is conditioned upon approval, typically when re-vegetation is established.	Bonds are released after acceptable plant growth on sites.	Bond release is conditioned on approval of the supervisor.	Bond released after plugging fully approved.
Abandoned Well Clean-up Program	Yes. Approximately $10,000/year appropriated. Oil and Gas Division is to maintain a list of wells & holes requiring clean-up. This is done by maintaining files of complaints that are received.	Yes. Last biennium spent $10,000. Could spend up to $50,000 this biennium.	No	No

SAFETY	COLORADO	NEW MEXICO	ALBERTA
Blowout preventer equipment? (BOP)	In proven areas use of BOP is to be in accord with established practice. In unproven areas, BOP, mastergate, choke and kill lines or lines of proper size and working pressure are required. Owner required to "keep the well under control at all times". Normally equipment is to be in accordance with API recommended procedures. Specific BOP components are listed, and must be inspected daily while in service. Surface casing sufficient to prevent blowouts required. Automatic control valves are required on wells located less than 150 feet from a residence, and they must be activated by a secondary fuel supply. Safety valves are required if any indication the well will flow hydrocarbons. Number of the public road to be used to access the rig and emergency phone numbers must be posted on the rig.	Yes, in areas of unknown or high pressure, a proposed blowout prevention program must be submitted with the permit to drill. District supervisor may modify if necessary. BOP must be tested once every 24 hours during drilling.	All wells must have BOP adequate to shut off any flow. Six well classifications based on depth, and types of BOP for each class are specified. Detailed equipment and operational spec's for casing bowls, accumulator systems, kill systems, bleed off systems and mud tanks are included in the regulations. Test requirements are specified for various steps in the drilling process. Rig crews are to be trained to operate the equipment. Drills are required by each crew every 7 days and persons with certain qualifications must be on site. There are special regulations for servicing, well completion, or reconditioning. Inspectors may require pressure tests of BOP equipment and safety drills. Schematic diagrams of the equipment are included in the regulations.

SAFETY	MONTANA	NORTH DAKOTA	WYOMING	UTAH
Blowout preventer equipment? (BOP)	Operators are required to "take all available precautions to prevent any... well from blowing open." Chokes or other adequate control equipment are required at all flowing wells. In proven areas BOP must be in accordance with established practice. In unproven areas, a mastergate, adequate BOP, choke and kill line of proper size and working pressure are required.	Yes. Necessary precautions are required to keep wells under control, including a blowout preventer and high pressure fittings attached to properly cemented casing strings. Pressure tests required every 2 weeks. Pipe rams must be operated and tested every 24 hours.	Yes. Equipment specified (doublegate, hydraulically operated preventer, etc.) for wells in areas where formation pressures are unknown. Installation, pressure and testing specs are listed. A map included in the regulation specifies where the "unknown pressures" rules apply. A schematic diagram of the equipment is also required.	In wildcat territory, "all reasonably necessary precautions" must be taken to control the well. BOP in accordance with established practice is required in proven areas. Test requirements specified. BOP in possible H_2S areas shall be "suitable".

SAFETY	COLORADO	NEW MEXICO	ALBERTA
Is safety addressed in the regulations?	Yes	Yes	Yes
Emergency plans?	No plans required.	No plans required.	Yes, see H_2S discussion.
H_2S?	No special requirements.	There is a statewide rule that associated gas containing H_2S must be flared. An alarm system is required in case of equipment failure.	"Critical sour wells" are defined as having: 1) a maximum potential H_2S release rate of 2.0 cubic meters/second (M^3/s); 2) a rate of >0.3 and < 2.0 $M3/s$ located within 5 kilometers of an urban center; 3) a rate of >0.01 and <0.3 M^3/s if located within 1.5 Km of an urban center; and 4) any other well considering the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area, and the expected complexities of drilling the well. Applicants must meet special requirements, including submission of a satisfactory emergency response plan, a general description of how any serious problems would be handled, description of critical equipment, guarantee that adequately trained supervisors will be on site, requirements for a minimum 5-person drilling crew, for adequate safety personnel and equipment on site, and for a complete inspection and blowout prevention drill. Also, special requirements for casing. The input of local residents should be obtained as early as possible The emergency response plan must define the circumstances and process to initiate the emergency procedures and identify how a release of H_2S will be detected and located. An emergency zone, defined as the "worst case 100 ppm H_2S isopleth" must be identified by a specified method of calculation. On-site and off-site communication centers are to be established. The criteria to be used to decide to ignite a release of sour gas must be presented. Personal visits must be made to each resident in the emergency planning zone to discuss the initial plans and annually thereafter for updates. Methods and procedures for evacuation are to be specified in detail. An emergency plan may also be required for non-critical sour wells, although less detail may be sufficient. If an uncontrolled flow of H_2S were to occur, it would be ignited. Also, inspections of sour gas drill rigs are more detailed and more frequent than for other types of wells. Inspectors may order unsafe rigs to shut down until problems are corrected.

SAFETY	MONTANA	NORTH DAKOTA	WYOMING	UTAH
Is safety addressed in the regulations?	Yes	Yes	Yes	Yes
Emergency plans?	No plans required.	No plans required.	No plans required.	Yes, see H_2S discussion.
H_2S?	Any vented gas containing 20 ppm H_2S or greater must be burned. Operators must install workable ignitor systems. No variance allowed without written authorization based on circumstances such as isolation of well, restricted access, low volume or BTU's, and potential for human exposure.	Air quality agency requires all gas with any H_2S to be incinerated, flared or treated. Automatic pilots are required on the flare system. A new rule is being considered to require registration of all wells that produce gas with H_2S in order to determine that control technology is effective.	Equipment used in possible H_2S areas shall be "suitable." No special requirements for venting or flaring H_2S gas in the commission's regulations. A new policy of the air quality agency concerns venting that occurs in the context of completion tests or workovers. Verbal notice is required within 24 hours. If over 50 tons/year H_2S emissions, a report is required, stating the reason, time period(s) total amount and any efforts made to minimize.	General operating practices specified where there is gas containing 20 ppm or greater H_2S or in "unknown" areas. Written contingency plan required as part of drill permit application. Must specify actions to alert and protect workers and the public if there is an accidental release. Also, rig is to be sited to take advantage of prevailing winds, and must be areas cleared for safety and briefing the crew. Protective equipment to be on-site is listed. Detection and monitoring systems capable of sensing 10 ppm H_2S required. A flare system is required to safely gather and burn H_2S gas. Also, system additives are required to scavenge or neutralize the H_2S.

ON-SITE PROCESS WATER DISPOSAL	COLORADO	NEW MEXICO	ALBERTA
Exemptions from application/review requirements?	Yes, pits receiving 5 barrels a day or less on a monthly basis.	NW: 5 barrels or less, 10,000 ppm or less of TDS and 10 ft. above the water table; or ½ barrel or less of any other quality water; SE - 1 bbl/day per lease or 16 bbls/day total.	Not mentioned in available materials.
Liners	Liners, monitoring and construction inspections are required for pits that receive over 100 barrels per day with total dissolved solids of 5,000 ppm or greater. The commission may adopt area rules for pit liners where domestic water supplies underlie significant areas. The permit application must include a description of lining material and method of construction. Material must be impervious, weather resistant, and resistant to substances likely to be in the water or waste. Inspector must be given opportunity to inspect leak detection system and liner materials prior to installation.	In southeast, 600 sq. ft. evaporative surface/barrel, a liner of at least 30 mils in thickness and otherwise resistant to damage. Application requires description of liner material, answers to a series of questions about resistance of the material, a manufacturer's brochure, water analysis, water production data for the previous 6 months and 3 months, method of hydrocarbon entrapment, diagram of pit & leakage detection system. Inspections occur during construction.	Pits must be constructed of clay or other suitable lining material; may not have surface of more than 300 sq. meters and must be located so natural run-off water will not collect. Plastic liners are rarely used. If pit is for long term use, compaction of the clay may be required.
Permeability Standards?	No	No	No
Monitoring?	No.	Yes, in the SE, pits must have underlying gravel filled sumps and laterals or other suitable devices for detection of leakage.	At least quarterly sampling is required and in some cases, monthly.

ON-SITE PROCESS WATER DISPOSAL	MONTANA	WYOMING	UTAH
Exemptions from application/review requirements?	Not applicable.	Yes, pits receiving less than 5 barrels/day. However, monthly monitoring and chemical analysis is required.	Yes, pits receiving less than 5 barrels/day, although notice of the location and source of the water must be filed and no significant migration to the subsurface can result. All pits existing prior to the rule must be registered and if necessary, put on a compliance schedule.
Liners	Salt water pits must be underlaid by heavy clay or hard pan.	Liner decisions made on a case by case basis.	Lined pits are required for waters that do not meet the criteria listed above. In addition to the information listed for unlined pits, plans must include method for disposal of solids and where disposal will occur, leak detection method, type of material used to construct the pit, installation method. Geologic investigation required for large volume facilities. Liners must either be 2 feet of impervious in-situ soils (complete analysis required to demonstrate capability), clay liners (<u>at least</u> 2 feet thick and tests required) or artificial liners such as concrete or plastic (minimum criteria specified and leak detection or sump system required).
Permeability Standards?	No	No	Clay or soils must have maximum permeability co-efficient of 10^{-6} centimeters/second both horizontally and vertically unless tests show the wastewater will not migrate.
Monitoring?	No	Monitoring may be required on a case by base basis. Also, pits may not be constructed on fills, in a drainage or floodplain or where there is standing water.	Any pit receiving more than 100 bbls/day must have a monitoring well(s) that penetrates the nearest aquifer. This requirement does not apply to artificially lined pits.

ON-SITE PROCESS WATER DISPOSAL	COLORADO	NEW MEXICO	ALBERTA
Are surface pits allowed?	Yes	Yes	Yes
Special report forms or application?	Monthly reports on the amount of water produced per well and transported (by lease, delivery location and type of fluids). There is a special permit and application form for earthern pits.	Yes. Statewide reports on volume of water produced per well. Transporters of produced water are required to obtain special authorization. In the NW, operators file a pit registration form, including maximum daily discharge to the pit/day, depth to ground water, and water analysis (TDS or conductivity and temperature). In the SE disposal in unlined pits is prohibited. Permits for new lined pits are allowed only on leases where production is declining. Previously approved pits must also obtain a permit and meet current minimum spec's. In designated "vulnerable areas" unlined pits are prohibited as of 1/1/87 in the NW.	Yes. Reports on the amount of water produced per well. Plans must be filed to show how pollution will be prevented. Not more than 15 cubic meters water/month may be stored in pits. Board can increase or decrease the amount, or prohibit pits altogether due to salinity, soil characteristics or other circumstances. Where topography will not permit adequate surface capacity, water must be stored in tanks prior to final disposal.
Information required prior to approval?	Distance to closest surface water; a water disposal plan (e.g., evaporation, hauled, disposal well); type sealing material; chemical analysis of water and underlying water supplies if not separated by a natural impermeable layer; drawings, maps and logs of the operation; maps of the area, description of soil and strata between the pit and nearest domestic water supply; volume of water to be received daily; and estimates of evaporation rates.	Statewide detailed guidelines include pit design and construction specs, directions on preparing the pitbed and installing a double liner system, skimmer ponds/tanks, and contingency plan if leaks occur. Application requirements include hydrologic and geologic data; a map or site plan; detailed design data on use, type and volume of effluents; liner type, thickness and compatability with effluents; leak detection methods and leak prevention and procedures.	Plans must specify elevations of the normal high water mark and surrounding land and the measures to meet particular circumstances, including construction and maintenance of dikes, reservoirs, and final disposal of muds, oil, water, and other fluid.

ON-SITE PROCESS WATER DISPOSAL	MONTANA	WYOMING	UTAH
Are surface pits allowed?	Yes	Yes	Yes
Special report forms or application?	Reports on the amount of water produced per well. No pit application is required. Salt water pits are allowed where there is tight soil such as heavy clay or hard pan. Where the underlying soil is porous or closely underlaid with gravel or sand stratum, salt or brackish water may not be impounded in pits. Pits that fail to properly impound such water can be condemned.	Reports on the amount of water produced monthly, per well. Pit application also required.	Reports on the amount of water produced per well and water transportation reports. Pit construction permit also required. The oil and gas agency is taking over jurisdiction from the Department of Health for all produced water disposal, including on-site and commercial disposal pits. Unlined pits are allowed only if the water has less than 5,000 mg/l total dissolved solids (TDS) and non-toxic levels of chloride, sulfate, oil and grease and heavy metals, or if all or most of the water is being beneficially used.
Information required prior to approval?	No special information required.	The application must contain a plan view and topo map, and state the expected amount of water/day, subsoil type, water analysis, distance to closest surface water, a plan for pit sealing or water proofing, and for final water disposal. Commission may modify plans where there is high potential for surface or ground-water contamination, including lining, monitoring systems, and provisions for periodic reporting.	Applications for unlined pits include topo map showing size and location of the pit, amount and sources of the water, evaporation rates and annual rainfall in the area, estimated percolation rate based on soil characteristics, depth and extent of all useable aquifers within one square mile of the site. (Useable water contains less than 10,000 mg/l TDS.) If the water contains more than 50,000 mg/l TDS, liners are required. Emergency pits do not have to meet these requirements as long as the water is removed as soon as possible. After construction but before use, the state must have an opportunity to inspect and approve the pit by letter to the land-owner and operator. Plan review and permit issuance occurs within 30 days.

RESERVE PITS	MONTANA	NORTH DAKOTA	WYOMING	UTAH	ALBERTA
Construction Specifications?	No (excepting the "sealing" reference quoted on previous page).	Top 8" of topsoil must be stockpiled and reused. Fencing may be required and if so, it remains until the pit is dry.	Where practical, topsoil is stockpiled. Flagging and fencing required at the time the rig is moved. Use of any dispersant or surface reduction agent that destroys or reduces the fluid seal of a reserve pit is prohibited. Public hearing and permission required before anyone may chemically or mechanically treat a reserve pit.	Pits must be constructed to prevent surface discharge or significant subsurface migration of liquids.	No
Siting?	No	Yes, based on site visit prior to construction.	Yes. Authority over location of pits is specifically included in the regulations.	Yes, based on the pre-drill inspection.	No
Reclamation	Reclamation is undertaken as landowners specify, usually in the minimum time possible. Operators may discharge remaining fluids down hole or haul mud for use at other sites, but these are not requirements. If not removed, solid wastes are to be buried to a minimum depth of 3 feet. As soon as weather or ground conditions permit, surface must be restored to previous grade and productive capability.	Re-seeding with native species or reclamation to the specifications of the landowner is required. Restoration to as close to original condition as possible. Within 1 year pits must be filled in & leveled. Notice of Intent to reclaim required. Verbal approval needed to commence. Restoration of access road & pad (including removal of gravel & scoria) required unless landowner requests otherwise. Trenching is used to remove remaining water.	In accordance with landowner stipulations, but must reclaim within one year. Notice required on completion.	In higher altitudes some land application of fluid (solids removed & water treated) or injection is allowed. Elsewhere, fluids evaporate & muds buried on-site. Health Dept. (HD) requires that remaining liquids go to approved ponds. Surface discharge allowed if no environmental damage would result, based on HD analysis & landowner specs. Surface reclamation stipulations may be attached to the drill permit.	Upon well abandonment, all liquid wastes & drilling fluids are to be disposed at an approved waste processing facility unless the board approves otherwise. The area must be cleared of debris & all excavations filled in. Under land conservation regulations, a reclamation plan may be required, including a description of proposed revegetation methods.

:SERVE PITS	MONTANA	NORTH DAKOTA	WYOMING	UTAH	ALBERTA
›ecial permit : application ›rm?	No	No	Yes	No	No. However, the regula lations are being revised to contain more explicit requirements.
ite specific ıformation: ›ils? ater?	No, However, pits must be constructed "adequate to prevent undue harm to the soil or natural water".	No. Field inspectors visit the site after the drill permit is issued to survey the pit location. If the site is appropriate an unlined pit is allowed.	Yes. Required information includes: plan view; topo map; mud program description; period pit will be used; plan for final disposal of pit contents (e.g. evaporation, hauling or disposal well); chemical analysis of water; map of drainage and irrigation systems; type of sealing material and application method; subsoil type.	There is a pre-drill inspection to determine the soil type and depth to water.	Approval is required for both surface and subsurface disposal. Disposal on site is limited to 6,000 barrels and the waste must be confined to the lease. The Board may allow disposal in excess of 6,000 barrels based on an application showing that the fluids will be confined. One week notice is required before disposal commences For on-site disposal the lease must be more than 300 feet from the normal high water mark of any water body or well. To dispose off-lease the fluids must meet certain chemical criteria or be treated.
‚iner Requirements	"When a salt base mud system is used..., the reserve pit shall be sealed when necessary to prevent seepage". In practice, most pits in the Williston Basin are lined with plastic or bentonite, but not in other basins where fresh water drilling muds are primarily used.	The need for liners is determined on a case by case basis. Soil characteristics and the landowner's wishes are considered.	Determined case by case based on the application. Also, pits may not be constructed in a drainage or floodplain or areas that collect standing water. Unlined pits may not be constructed on fills. Most reserve muds are not salt based.	Based on pre-drill inspection. Require either tight soil or lining in a manner acceptable to the Board. Reserve pits are prohibited in porous soils unless lined.	Liner requirements are not specified in the regulations.

PERMITS TO DRILL	UTAH	COLORADO	NEW MEXICO	ALBERTA
After An Application Is Received, How Soon Is A Permit Issued?	7-14 day service.	Same day service.	Same day service.	Two days, if all required information is included. Drill plans must address site construction and maintenance, dikes, reservoirs and final disposal of mud, oil, water and other fluids.
When Do Site Inspections Occur?	Pre-drilling inspection required. Occurs within 15 days of receiving an application.	Occurs during drilling.	After drilling is completed.	Notice of intent to drill required 24 hours in advance. Pre-drill inspections may be made depending on the location and other information in the application. The various provincial agencies have identified geographic areas of concern (environmentally sensitive, steep slopes, streams etc.) Personnel from several agencies may inspect drill sites in areas of concern to determine if drilling and road construction can be done in a satisfactory manner.
Environmental Stipulations?	Yes. All stipulations are based on the pre-drill inspection. Landowners are invited to attend. Stipulations may include surface use. The major concern is how pits are constructed. (See Reserve Pits)	No	No	Yes. The Board may prescribe the location of any road that is required and the conditions relaing to its construction, as well as any other conditions or stipulations deemed necessary. The Board also may deny a license.
Fee	None	$75	None	$250

PERMITS TO DRILL	MONTANA	NORTH DAKOTA	WYOMING
After An Application Is Received, How Soon Is A Permit Issued?	Same day service.	Same day service.	Same day service.
When Do Site Inspections Occur?	In most cases inspectors discuss drilling methods with crews by telephone before drilling occurs. Site inspection occurs during drilling.	After the permit is issued but before the rig moves in.	No site inspection prior to drilling unless data required for the application is missing.
Environmental Stipulations?	The operator must give a plan of work to the surface owner sufficient to evaluate the effects of drilling on use of the property. The surface owner makes agreements concerning road placement and surface disturbance.	Yes, primarily relating to pit construction.(See Reserve Pits)	Yes, primarily relating to pit construction. In one case the commission examined alternative roads to a proposed site. (See Reserve Pits)
Fee	\$ 25 for holes less than 3,500'; \$ 75 for holes 3,501'-7,000'; and \$150 for holes 7,001' and greater depth.	\$100	\$25