Report of Investigation 17

CBM-PRODUCED WATER DISPOSAL BY INJECTION, POWDER RIVER BASIN, MONTANA

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DISCLAIMER

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ABSTRACT

In the Powder River Basin, the quality of water produced during coalbed-methane (CBM) development is sufficient for domestic and livestock use, but the high sodium adsorption ratios in much of the water make it unsuitable for irrigation. In addition, the water could potentially impair surface streams currently used for irrigation. Therefore, water management methods, including subsurface injection, that preserve beneficial uses without degrading surface water resources are highly desirable. Water injected into the subsurface should be in zones shallow enough to be economically recovered. The main goal of this project was to identify potential zones for injection in the Tongue River Member of the Fort Union Formation (above the Lebo Shale Member). Of particular interest were thick, porous, and permeable channel sandstone units. In addition, deeper coalbeds in the Tongue River Member could also be targets for injection if they were not being developed for CBM. This study was not intended to find injection targets capable of handling the disposal of all the produced water, but to use injection in conjunction with other approved methods to develop an economically and environmentally feasible water management system.

Mapping and correlation of channel sandstones in the Tongue River Member have defined stacked northeast-trending paleo-river systems. Some of the channel sandstones are more than 100 ft thick and have porosities as high as 30 percent. These sandstone bodies should prove to be excellent zones for injection of CBM-produced water. Although these channel sandstones are present locally, they are not always present wherever an injection well may be desired. In addition, there is substantial uncertainty inherent in mapping channel sandstones, especially in areas of limited well control.

Our engineering injectivity evaluations concluded that injection of significant volumes of water into channel sandstone is possible. Reasonable injection rates (200–4500 barrels/day or 6-130 gallons per minute) can be expected depending on sandstone thicknesses completed and the injection well pressure. The well pressure must not exceed an estimated fracture gradient of 0.70 psi/ft.

EXECUTIVE SUMMARY

Coalbed-methane (CBM) development in the Paleocene Fort Union Formation in the Powder River Basin is currently one of the most active gas plays in the United States.

Gas in coalbeds is trapped by hydrodynamic pressure. Therefore, gas production requires reduction in water pressure in order to release the gas held in the coal. The pressure reduction is achieved by pumping relatively large volumes of water from coalbed reservoirs.

CBM-produced water in Montana is of sufficiently good quality for domestic and livestock uses. However, it has high sodium adsorption ratio (SAR) values, making it unusable for irrigation for most of the soils in the area ($SAR = Na/[(Ca+Mg)/2]^{1/2}$). Consequently, disposal options must preserve beneficial use while not degrading surface waters that are used for irrigation.

Most of the CBM development is in coalbeds in the Tongue River Member of the Fort Union Formation. The Fort Union Formation is divisible into three members: in ascending order, the Tullock, Lebo, and Tongue River.

The focus of this research was to identify specific potential injection targets. A complicating factor for injection is that potential shallow injection zones are saturated with water, and care must be taken not to exceed the fracture gradient as water pressure is increased. In addition, these zones have lower injectivity than deep injection zones such as limestone beds in the Mississippian Madison Group. Channel sandstones are probably the best targets for injection because they have more favorable porosity and permeability, and because injecting into coalbeds may have conflicts with future CBM development. Six channel sandstone units were identified in the Tongue River Member, informally named ‘A’ through ‘F’ in ascending order. It is clearly evident from isopach maps that the channels are widely distributed and that potential injection targets will not be available in every location where an injection well is desired. In other words, injection may not be technically feasible in all locations at any cost.

Because of the inherent uncertainty in the mapping of channels, the design of an injection well was based on an existing well with excellent channel sandstone development. The well chosen was the International Nuclear Corporation, State MT Minerals #1, in sec. 28, T. 9 S., R. 44 E., Big Horn County, Montana, which encountered well-developed channel sandstones in the 'A,' 'C,' and 'D' intervals and for which good resistivity and sonic logs were available.

CBM well production in the Powder River Basin typically starts with significant water production rates (in excess of 200 barrels/day) and low gas production rates. Over time water rates decrease to smaller volumes, and gas rates increase to their maximum values. This requires the handling of variable water volumes, and supports the central gathering of water from multiple wells for combined disposal or treatment.

Data from four active water disposal wells completed in Wasatch and Fort Union sand aquifers in the northern Powder River Basin showed reasonable injection rates (200–4500 barrels/day) depending on the thickness of sandstone available for injection. Disposal well histories over a period of 2 to 16 months indicated no change or increase in well pressures for injected volumes of 36,000 to 600,000 barrels of water. These data correspond to an average effective formation permeability of 31.5 millidarcies, which should accommodate reasonable injection rates without stimulation. This experience confirms the results of log data analysis of the International Nuclear Corporation well.

Well completion designs for newly drilled injection wells to depths of about 2000 ft would reasonably assume injection down production casing. The casing would be cemented fully to the surface and perforated with at least four holes per foot in target sands totaling 100 ft to 300 ft of net pay thickness.

This evaluation indicates that significant, but limited, volumes of water could be injected into zones identified in the Tongue River Member of the Fort Union Formation. Because of the difficulties in locating well-developed channel sandstones and because the target zones are already at least partly water-saturated, a combination of water disposal methods, including surface discharge, infiltration ponds, direct agricultural and domestic use, treatment, and injection will probably yield the most feasible disposal plans and provide a balance between environmental and economic constraints.

INTRODUCTION

Project Location

The project area is the Powder River Basin of southeastern Montana, encompassing parts of Yellowstone, Bighorn, Rosebud, Treasure, Powder River, and Custer Counties (fig. 1).

Background

Coalbed-methane (CBM) development in the Powder River Basin is currently one of the most active gas plays in the United States. Annual total production was 255 billion cubic feet (BCF) for 2001 and 324 BCF for 2002 in the Wyoming portion of the basin (Potential Gas Committee, 2003). In the Montana portion of the basin approximately 41 BCF of gas has been produced as of 2004 (Montana Board of Oil and Gas Conservation, 2004). Reported coalbed gas reserves for the Powder River Basin are approximately 26 trillion cubic feet (Potential Gas Committee, 2003).

Although coalbeds in the Powder River Basin extend well into Montana, the only established CBM production in Montana to date is a single field near the Wyoming border, the CX Ranch, operated by Fidelity Exploration. A few other prospects are in early development in the southern part of the Montana Powder River Basin.

Figure 1. Index map of the project area encompassing the Powder River Basin of southeastern Montana and showing counties and Indian reservations in the project area.

Gas in coalbeds is trapped by hydrodynamic pressure. Gas production requires reduction in water pressure in order to release the gas held in the coal. The pressure reduction is achieved by pumping relatively large volumes of water from coalbed reservoirs. Production of CBM by this method is reviewed more fully by Wheaton and Donato (2004a).

Water Issues

Total dissolved solids values for CBM-produced water in Montana range from 900 to 2,500 parts per million. Dissolved ions are mainly Na and HCO3. Water is therefore of sufficient quality for domestic and livestock uses. However, much of the water has high sodium adsorption ratio (SAR) values, which is a function of the ratio of the concentration of sodium to calcium plus magnesium (SAR = Na/ $[(Ca+Mg)/2]^{1/2}$). The SAR value is a predictor of how water may interact with clays in soils; water with high SAR values (20 or more) may decrease the permeability of clay soils and therefore reduce its productivity (Hanson and others, 1999). Consequently, disposal options should preserve beneficial use while not degrading surface waters that are used for irrigation.

GEOLOGY OF THE MONTANA PORTION OF THE POWDER RIVER BASIN

Structural Geology

The Powder River Basin is a Laramide asymmetrical north–northwest-trending structural basin with its axis near the western margin. The Montana portion of the basin is bounded on the west by the Bighorn Mountains, on the east by the Black Hills uplift, and on the north by the Miles City Arch (fig. 2).

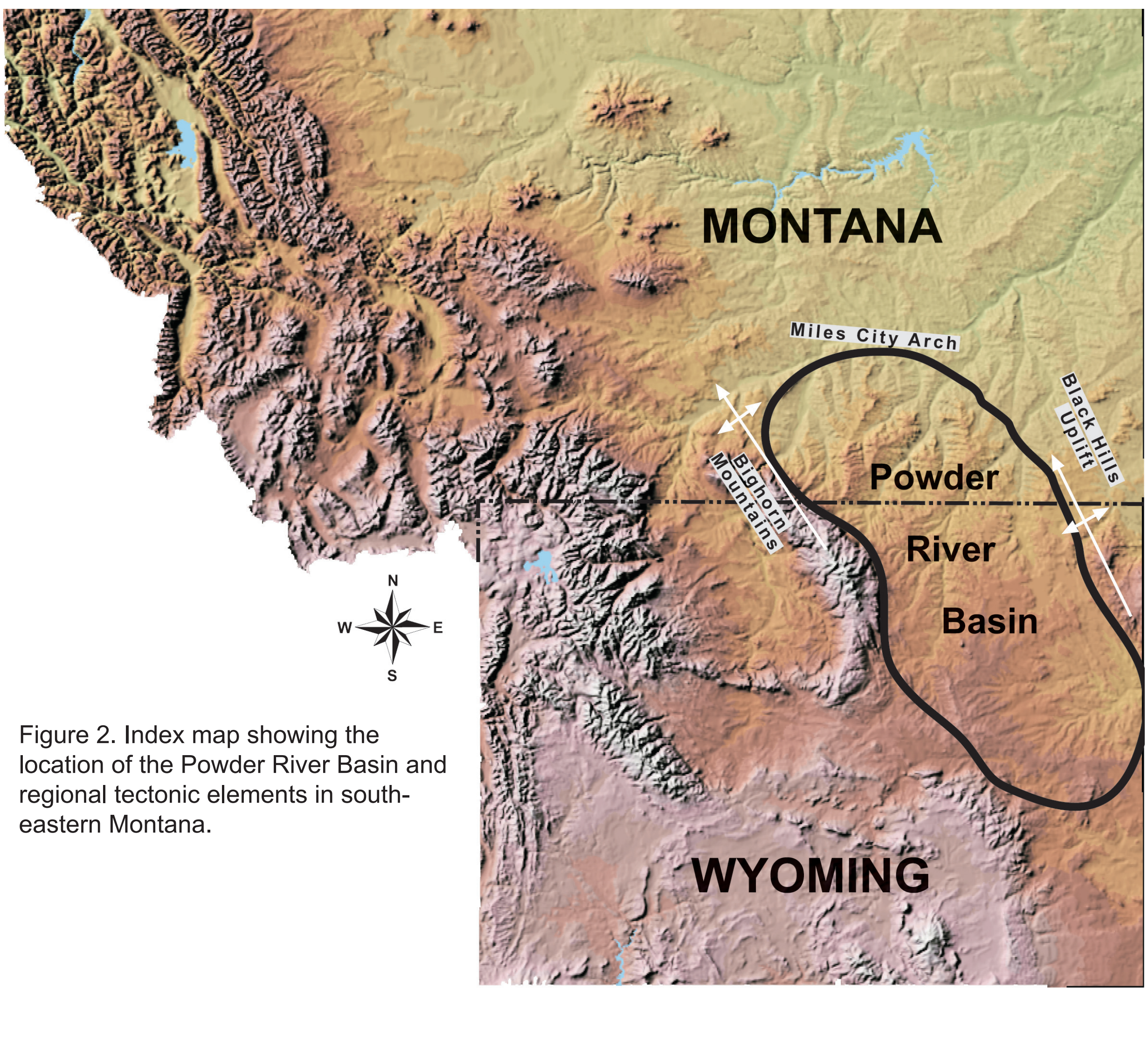

Figure 2. Index map showing the location of the Powder River Basin and regional tectonic elements in southeastern Montana.

A structure-contour map of the top of the Lebo Shale Member of the Fort Union Formation illustrates that the structural axis of the Powder River Basin trends north–northeastward in the Montana portion of the basin (Lopez, 2005). The Basin is not a simple smooth syncline, but has isolated structural closures and anticlinal ridges (Lopez, 2005) that are probably controlled by Laramide basement faults. These structures may have formed traps where natural gas from coalbeds may have migrated into sandstone reservoirs.

A system of northeast-trending, en echelon, normal faults is present in townships 1 and 2 south and ranges 38–40 east (pl. 1). These faults are thought to be an extension of the Lake Basin Fault Zone of central Montana (Robinson and Barnum, 1985). Another system of northeast-trending, en echelon, normal faults is present at the south edge of the region, controlling the Ash Creek oil field and passing through the CX Ranch CBM field. This fault system is probably the surface expression of a strike-slip basement fault zone that is the eastward extension of the Nye-Bowler Fault Zone.

Linear features defined by alignments of drainages and other geomorphic features are clearly evident in topographic patterns and on satellite imagery. They were mapped for this project to identify areas of potential natural fracturing using Advanced Spaceborne Thermal Emission and Reflection Radiometer (ASTER) imagery. These northeast- and northwest-striking lineaments are for the most part in two sets: one is parallel and sub-parallel to the faults mapped in the area; the other set is approximately orthogonal to this set (pl. 1). Similar interpretations were reported by Maars and Raines (1984) and by Smith (1980), who also inferred that modern drainages are probably controlled by these fracture (joint) systems.

Stratigraphy

The project area is underlain, for the most part, by rocks of the Paleocene Fort Union Formation. Locally, in the southern part of the area, the overlying Wasatch Formation is present. The Fort Union Formation is divisible into three members: the Tullock, Lebo, and Tongue River (fig. 3). The Tullock Member is 130 to 1,000 ft thick in the area, thickening to the south, toward the center of the basin. This member consists of interbedded mudstone and argillaceous sandstone and minor amounts of coal.

The Lebo Member is about 100 to 500 ft thick and is for the most part made up of mudstone and lesser amounts of sandstone and low-quality coalbeds.

The Tongue River Member is about 500 to over 2000 ft thick, thickening to the south into the center of the basin. It is composed of inter-bedded mudstone, argillaceous sandstone, and coal. There

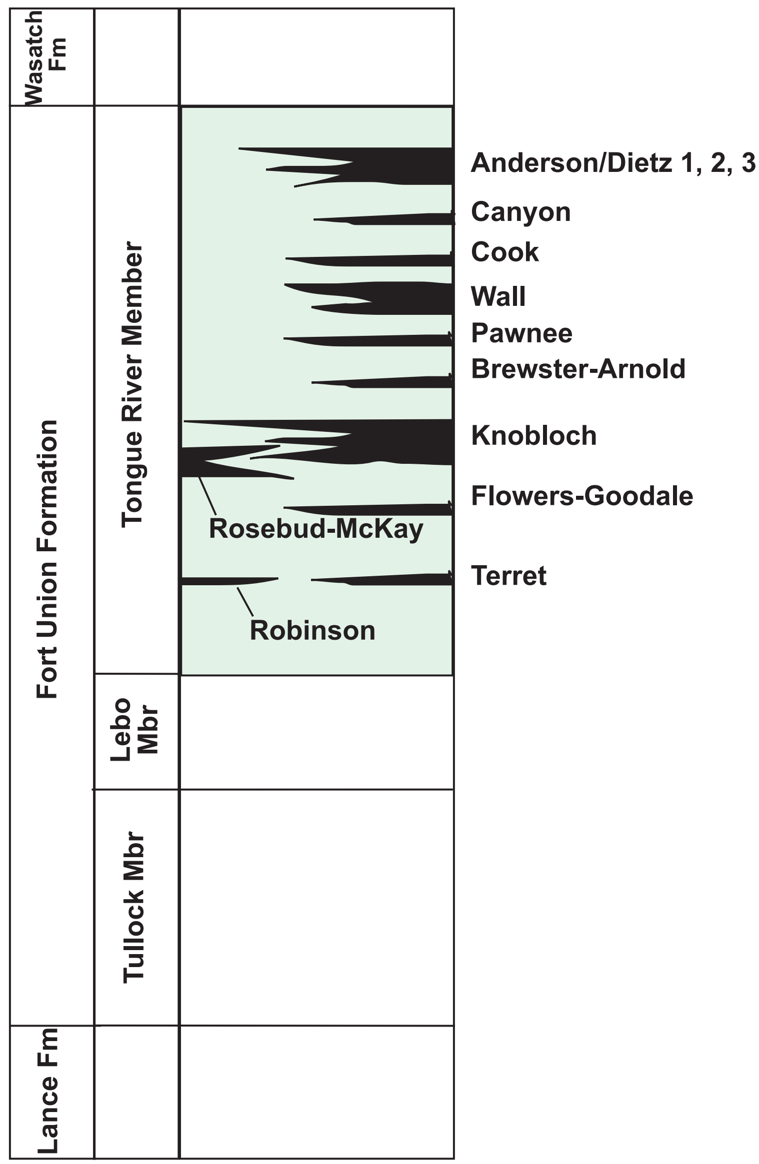

Figure 3. Generalized stratigraphic column of the Fort Union Formation in the Montana portion of the Powder River Basin, showing coalbeds generally present. Not all coalbeds are included and thicknesses are not to scale.

are also several thick clean channel sandstone units within this member. Coalbeds in the Tongue River Member in Montana are numerous and extensive and can reach as much as 80 ft in thickness (see fig. 3).

Depositional Settings of the Fort Union Formation

During the Paleocene, the Fort Union Formation was deposited in continental environments dominated by fluvial systems, their associated floodplains, lakes, swamps, and wetlands; these fluvial systems were graded to and flowed eastward and northeastward toward the Cannonball Sea in what is now North Dakota and South Dakota (Brown, 1958; Robinson, 1972; McDonald, 1972; Flores and Ethridge, 1985; Cherven and Jacob, 1985; and U.S. Geological Survey Fort Union Coal Assessment Team, 1999). In the Powder River Basin region of Montana and Wyoming, deposition was partly controlled and affected by continued Laramide deformation (U.S. Geological Survey Fort Union Coal Assessment Team, 1999). The sandstones deposited in the primary fluvial channels of the depositional system offer the greatest opportunity for injection of CBM waters.

GEOLOGIC ASSESSMENT OF INJECTION TARGETS

Because the quality of CBM-produced water is sufficient for domestic and livestock uses, it should be injected into zones that will preserve beneficial use; potential zones for injection must be relatively shallow. Potential zones for injection include coalbeds not being developed for CBM and porous and permeable sandstone in the Fort Union Formation; other formations are too deep to preserve economically feasible beneficial use.

The focus of this research was to identify specific potential injection targets. A complicating factor for injection is that potential shallow targets are water-saturated and the increase in water pressure due to injection will be limited by the fracture gradient for the zone. In addition, injectivity in these zones is not as great as that of well-known deep injection zones, such as limestone beds in the Madison Group. Therefore, a combination of water disposal methods, including surface discharge, infiltration ponds, direct agricultural and domestic use, treatment, and injection will probably yield the most feasible disposal plans and a balance between environmental and economic constraints.

Water chemistry in injection target zones must be similar to that of the CBM-produced water in order to prevent precipitation or dissolution that could inhibit injection and cause ground-water quality degradation. Based on available data and knowledge of the ground-water flow systems in the Powder River Basin, it is assumed that because the ground-water flow paths are similar, water quality in channel sandstones will be similar to that in nearby coalbeds (Wheaton and Donato, 2004b; Wheaton and others, 2005, 2006). Chemical and biochemical processes transform calcium-magnesium ground water near recharge areas to sodium-bicarbonate water in areas of CBM accumulations (Van Voast, 2003; Wheaton and Donato, 2004a). Nance Petroleum Corporation, which operates several injection wells just south of the Montana–Wyoming border, has sampled ground water from Tongue River Member sandstones. They found that the water is chemically similar to CBM-produced water and is not of better quality, so degradation restrictions do not apply (personal communication, 2006, Dwayne Zimmerman, Nance Petroleum Corporation).

As mentioned above, the main potential targets for injection are coalbeds and thick, porous channel sandstone units. We have chosen to focus on channel sandstones because they have more favorable porosity and permeability for injection and because injecting into coalbeds may conflict with future CBM development. Six channel sandstone units were identified in the Tongue River Member of the Fort Union Formation. Figure 4 illustrates the stratigraphic positions of the sandstone units relative to the regional coal stratigraphy.

There are inherent difficulties and uncertainties with regional mapping of channel sandstones in the Fort Union Formation due to both poor quality and paucity of data. Because injected water must remain in the subsurface for a relatively long period of time, shallow zones are not feasible; they are likely to crop out and injected water could surface in

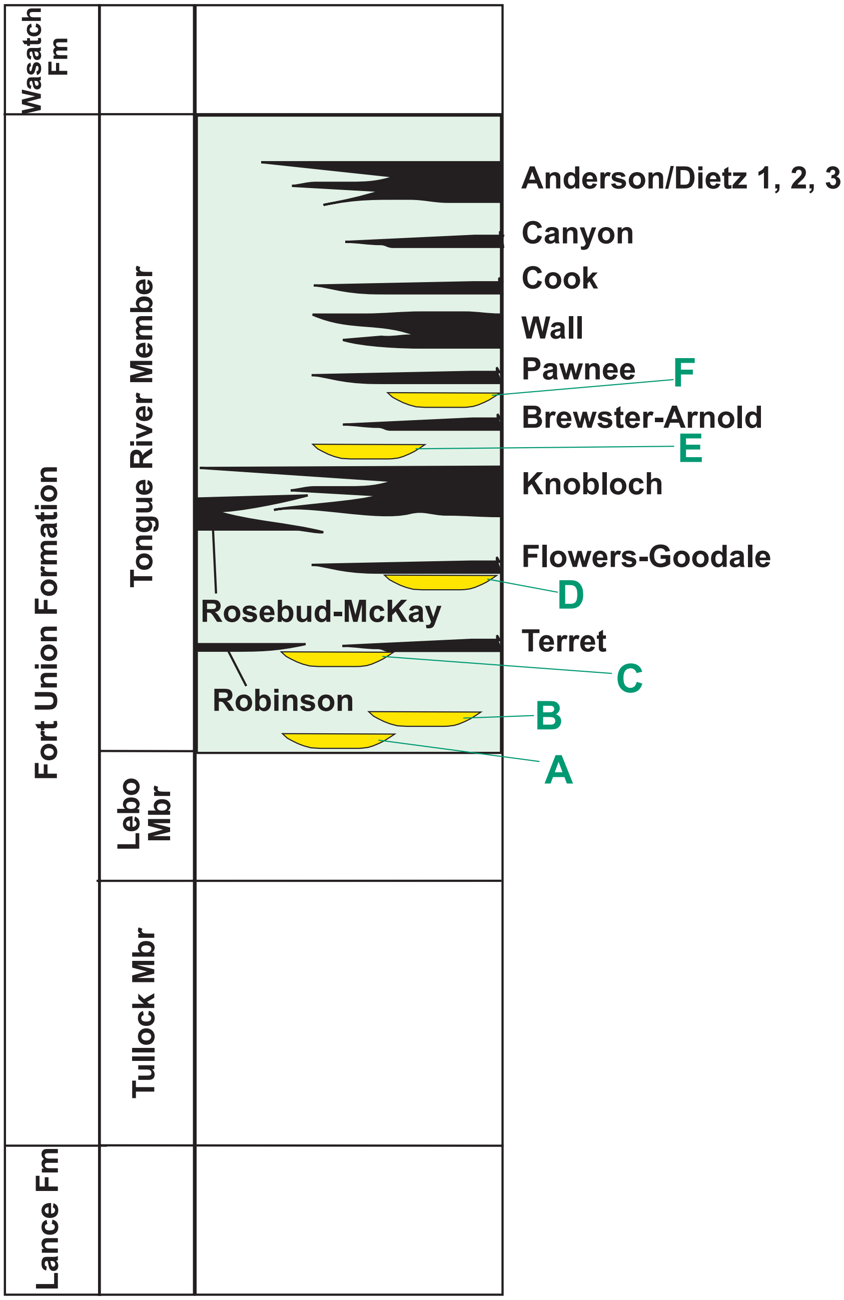

Figure 4. Approximate stratigraphic position of channel sandstones relative to major coalbeds in the Tongue River Member of the Fort Union Formation.

springs. Therefore, abundant shallow drilling, used to evaluate strippable coal resources, was not used in this evaluation.

Significant uncertainty in mapping of the channel sandstone units stems from a lack of data for three reasons: (1) commonly, oil and gas well logs begin below surface casing, at depths of approximately 500 to 1000 ft; (2) oil and gas exploration well density is low (1100 wells in project area; in many townships only a few wells have been drilled); and (3) correlating coal stratigraphy on logs from older wells is difficult and very uncertain because only e-logs are available.

In the project area, six channel sandstone units that form a stacked sequence of paleo-channels were mapped. The channel sandstones are informally named 'A'–'F,' from bottom to top; 'A' is the basal sandstone in the Tongue River Member. The thicknesses of some of the channel sandstone units are 100 ft or more. The typical log signature of a channel sandstone is shown in figure 5. Channel sandstone 'D' crops out along the northern edge of the Northern Cheyenne Reservation and is about 100 ft thick in these outcrops (fig. 6). Plates 2–7 are channel sandstone isopach maps that define the drainage patterns of these stacked channels. The similarity of the traces of the channels reflects similar paleo-geography through time and suggests that there may have been paleo-structural control on their locations.

Channel, or valley-fill, sandstones grade laterally into thinner muddy sandstones that may be overbank deposits (fig. 5). The log signature of these thinner sandstones is not always clearly characteristic of channel environments, whereas thicker sandstones, of 50 or more feet have more definite channel sandstone log signatures. Therefore, the channel edges are not easily determined and the character of sandstones shown outside the 50-ft contours cannot be regarded as conducive to injection of fluids (pl. 2–7).

It is clearly evident from isopach maps that the thick channel sandstones are only present locally, and that potential injection targets will not be available in every location where an injection well is desired. Injection may not be technically feasible at all locations at any cost. For example, at the CX

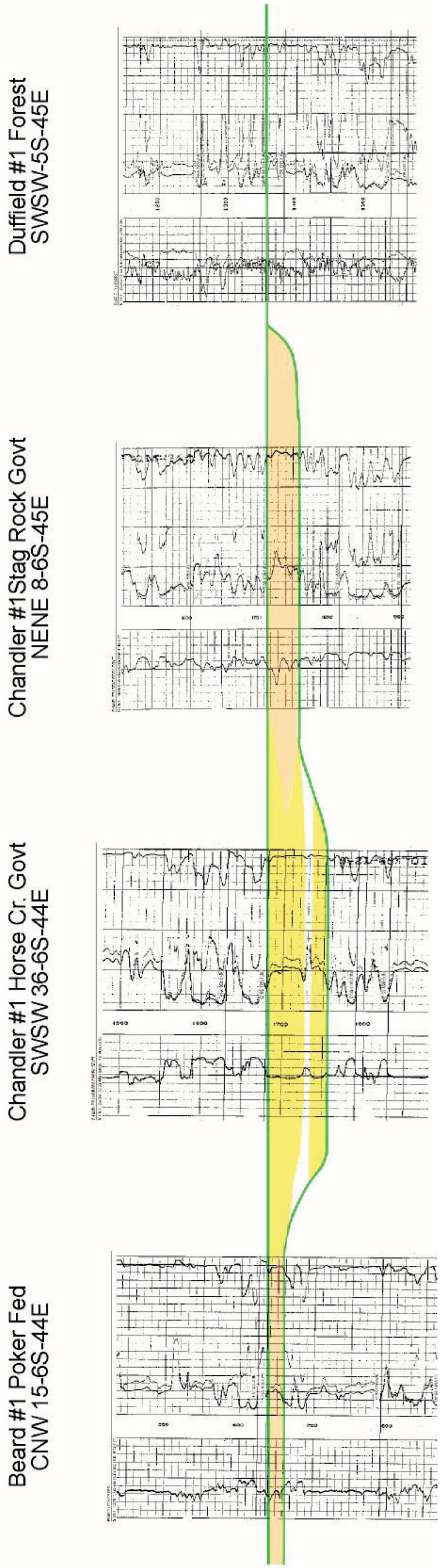

Figure 5. Typical log signature of Tongue River Member Channel Sandstone. 'D' Sandstone shown in this example.

Ranch field, no channel sandstone unit could be located and mapped in the subsurface using available oil and gas exploration well data. Transport of water over long distances will make injection uneconomical in most instances in the basin.

Density-neutron and sonic log data indicate that porosity in the channel sandstones is as great as 30 percent; lab measurements of porosity from plugs of outcrop samples of the 'D' sandstone were 27 and 33 percent (Wo and others, 2004). Permeability measurements from those same outcrop samples were 286 and 1062 millidarcies (md; Wo and others, 2004). Natural fracturing will increase the effective permeability of these units and enhance their use for water injection. ASTER satellite imagery was used to predict the presence of fractures. A fracture map interpreted from imagery lineaments shows areas where natural fracturing may be present and would potentially enhance the permeability of channel sandstone units (pl. 1).

The design of an injection well, described in the next section, was based on an existing well with excellent channel sandstone development. The intent is that an injection well could be developed successfully by twinning such a well. The well chosen was the International Nuclear Corporation, State MT Minerals #1, in sec. 28, T. 9 S., R. 44 E., Big Horn County, Montana. This well encountered well-developed channel sandstones in the 'A,' 'C,' and 'D' intervals and had good resistivity and sonic logs. Logs from this well illustrating the signature of the sandstone units are shown in figure 7. Faults and lineaments mapped in the area suggest that natural fracturing may enhance the permeability of the sandstones in the vicinity of this well (pl. 1).

ENGINEERING DISCUSSION AND INJECTION DESIGN

Downhole Water–Gas Separation

The production of natural gas from coalbed reservoirs requires the removal of water from the coal system (cleats and fractures) to reduce the system pressure and allow the gas to desorb from the coal. Initially a CBM well may produce only water until there is enough pressure reduction to start gas inflow. Powder River Basin CBM wells generally produce average initial water rates of 200–400 barrels/day (bbl/d) per well, decreasing to lower rates over a period of a few months to 2 years (U.S. DOI and State of MT, 2002). As water continues to be withdrawn from the coalbeds, the gas flow will increase to a peak rate and then will slowly decline as the reservoir pressure is depleted.

The downhole water–gas separation systems currently available in the industry are relatively expensive ($120,000–$300,000), and still face several technical challenges (Ogunsina and Wiggins, 2005). The proper sizing of a downhole single well re-injection pump would require controls to handle a steadily decreasing water volume. For the typical CBM water disposal volumes it is generally more cost-effective to use individual well pumps to lift the decreasing water volumes from each well, and then re-inject a combined larger volume gathered from multiple wells into a dedicated water disposal well. Current operators are successfully utilizing this method of re-injecting combined CBM-produced water streams into aquifers below the coal reservoirs in the Fort Union sands of the Powder River Basin (personal communication, Dwayne Zimmerman, Nance Petroleum Corporation, 2006).

Water Injection Expected Performance

Rate and Pressure Performance

The injectivity of water disposal wells (the rate and pressure performance) is determined by a number of subsurface reservoir conditions. The pertinent conditions are permeability, reservoir pressure, reservoir size (area, thickness, and porosity), fluid viscosity, wellbore skin damage, and wellbore pres-

Figure 6. The ‘D’ Sandstone in Reservation Creek at the north edge of the Northern Cheyenne Reservation. The sandstone is the very light rock in the lower part of the exposure.

sure losses. These conditions are related to injection rate in the expression of Darcy's law for fluid flow in porous media.

Darcy's law for steady-state, radial flow can be expressed as follows (Tiab and Donaldson, 2004):

$$q = \frac{0.00708kh\left(P_e - P_w\right)}{\mu \ln\left(r_e / r_w\right)},$$

where q is flow rate, bbl/day; k is permeability, millidarcies; h is net pay thickness, feet; P_e is reservoir boundary pressure, psia; P_w is wellbore injection pressure, psia; μ is fluid viscosity, centipoise (assume water = 1.0 cp); r_e is injection boundary radius, feet; and r_w is wellbore radius, feet.

This equation form is based on the following assumptions:

1. No gas dissolved in the water.
2. No inherent skin damage or skin improvement.
3. Reservoir flow rate at radial boundary equals well flow rate.

To determine the range of injection rates and pressures to be expected for given reservoirs, actual data from the subject reservoirs should be examined, and reasonable assumptions made for the parameters, if necessary.

Expected Reservoir Conditions

A Montana producer currently operates several water injection wells in Sheridan County, Wyoming for disposal of CBM-produced water. These wells are completed in various Fort Union and Wasatch sands very similar to the potential disposal zones 'A' through 'F' identified in the geologic assessment. Information from four disposal wells is given in table 1, and effective reservoir permeabilities are calculated (personal communication, Dwayne Zimmerman, Nance Petroleum Corporation, 2006). Assumptions made in these calculations are the same as those described in later sections.

An average of the effective permeabilities (k_{eff}) from these wells was 31.5 md, which is the assumed value used in estimating area well injectivity.

The identification of potential disposal zones in the project study area was characterized by a type well with available open-hole Induction Electric and Sonic logs. The type well was the International Nuclear Corporation, State MT Minerals #1 (fig. 7). Several potential disposal sands were evaluated from the type logs, and were assumed to be representative of the Fort Union sands mapped for this project. A table of general log analysis by zone is shown in table 2.

From this type log analysis, the total available net sand thickness is 281 ft. The weighted average sonic porosity, corrected for shaliness, is 18.2 percent. The total combined vertical porosity-foot volume is 51.14 ϕ-ft. Depending on the number of sands completed in a wellbore, the range of expected thickness is assumed to be from 100 ft to 300 ft throughout the study area.

Potential injection zones in the Fort Union are reported to be slightly underpressured at a gradient of 0.36 psi/ft (personal communication, Dwayne Zimmerman, Nance Petroleum Corporation, 2006). Considering a wellbore 2000 ft deep, the hydrostatic pressure of a full column of fresh water would exert a bottomhole pressure of 863 psia. Without additional

Table 1. Petrophysical properties from Nance injection wells

	Well 1	Well 2	Well 3	Well 4
Location	Sec 29, T. 58 N., R. 79 W.	Sec 14, T. 57 N., R. 76 W.	Sec 21, T. 58 N., R. 79 W.	Sec 21, T. 57 N., R. 76 W.
Compl. date	7/8/2005	5/22/2006	3/14/2005	3/15/2005
Cum Inj, bbl	63,520	36,168	201,326	610,890
q, bbl/d	200	600	1000	4500
h, ft	30	81	64	196
P_e–P_w, psia	194	550	530	975
k_{eff}, md	43	17	37	29

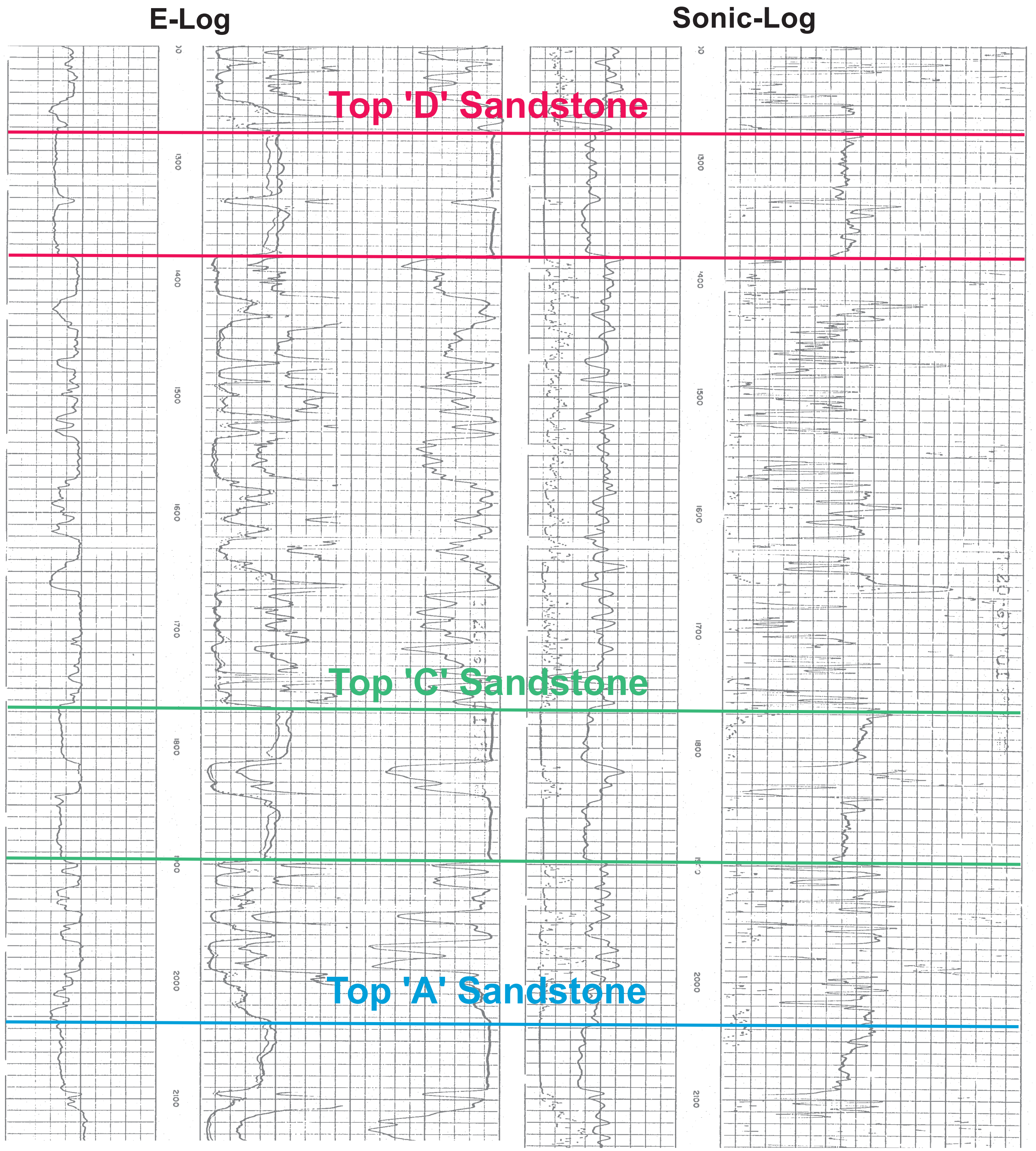

Figure 7. E-log and Sonic logs from the International Nuclear Corporation, State MT Minerals #1 well. Top and bottom of the 'D', 'C', and 'A' sandstone intervals are also indicated.

Table 2. General log analysis by zone

Zone	Depths (ft)	Net Thickness (ft)	Δt (µsec /ft)	ϕ_s	GR API units	SP (millivolts)	R_{ILD} (ohm-m)	V_{sh}	ϕ_{sc}
A	2034–2094	60	96	0.265	72	-20	20	0.275	0.192
C1	1745–1813	48	93	0.245	80	-13	25	0.36	0.157
C2	1840–1898	58	98	0.280	80	-15	22	0.36	0.179
D1	1258–1328	70	100	0.290	80	-16	22	0.36	0.186
D2	1335–1380	45	97	0.275	75	-17	23	0.30	0.193

Log analysis assumptions used:
Matrix sonic velocity = 19,500 ft/sec (sandstone)
Fluid sonic velocity = 5,300 ft/sec (fresh water mud)
Shale sonic travel time = 110 µsec/ft
Sonic compaction correction factor = 1.15
Dual Water Model shaly sand analysis method
V_{sh} determined from GR readings

Definition of terms:
Δt, µsec/ft = sonic travel time, microseconds per foot
ϕ_s = porosity fraction interpreted from sonic log
GR, API units, Gamma Ray log response in API units
SP, millivolts = spontaneous potential log reading in millivolts
R_{ILD} = induction log deep resistivity reading, ohm-meters
V_{sh} = Computed shale volume fractions from GR log readings
ϕ_{sc} = sonic porosity fraction corrected for shale content

wellhead pressure the static pressure differential (ΔP) in such an injection well would be 143 psia. The application of wellhead pump pressure would directly increase the ΔP magnitude.

The reservoir area affected by injection is arbitrarily assumed to be 1 mile in diameter surrounding an injection well. This is a reasonable limit considering that the Fort Union sands extend for long distances with little expected change in rock properties. For calculation purposes, the injected area radius is therefore determined to be r_e = 2640 ft. Also, a typical injection wellbore radius is assumed to be r_w = 0.5 ft, which is the hole size allowing for cement and casing.

Rate and Pressure Performance Correlations

Substituting the assumed values for viscosity, injection radius, and wellbore radius into the Darcy formula gives the following expression:

$$q = 0.0008(kh)(\Delta P).$$

With this formula the injection rate can be estimated based on a given reservoir thickness and desired wellhead pressure, using the expected k_{eff} = 31.5 md. Figure 8 is a plot of injection rate vs. pay thickness for wellhead pressures of 100 psia, 350 psia, and 800 psia. Also plotted are the four points of current actual injection performance from the previously referenced wells in Sheridan County, Wyoming.

These estimates assume negligible pressure losses in the wellbore and perforations. The actual well data are from wells injecting down 7-in diameter casing and with four perforation shots per foot of net sand pay. For tubing injection or very high rates, additional frictional pressure losses must be accounted for.

General conclusions can be drawn from this correlation as shown in table 3.

Table 3. Expected injectivity of water into Fort Union disposal zones in PRB

Wellhead Pressure = 100 psia	6.3 bbl/d per foot of NEP
Wellhead Pressure = 350 psia	12.6 bbl/d per foot of NEP
Wellhead Pressure = 800 psia	23.9 bbl/d per foot of NEP

Note. NEP, net effective pay for sandstone.

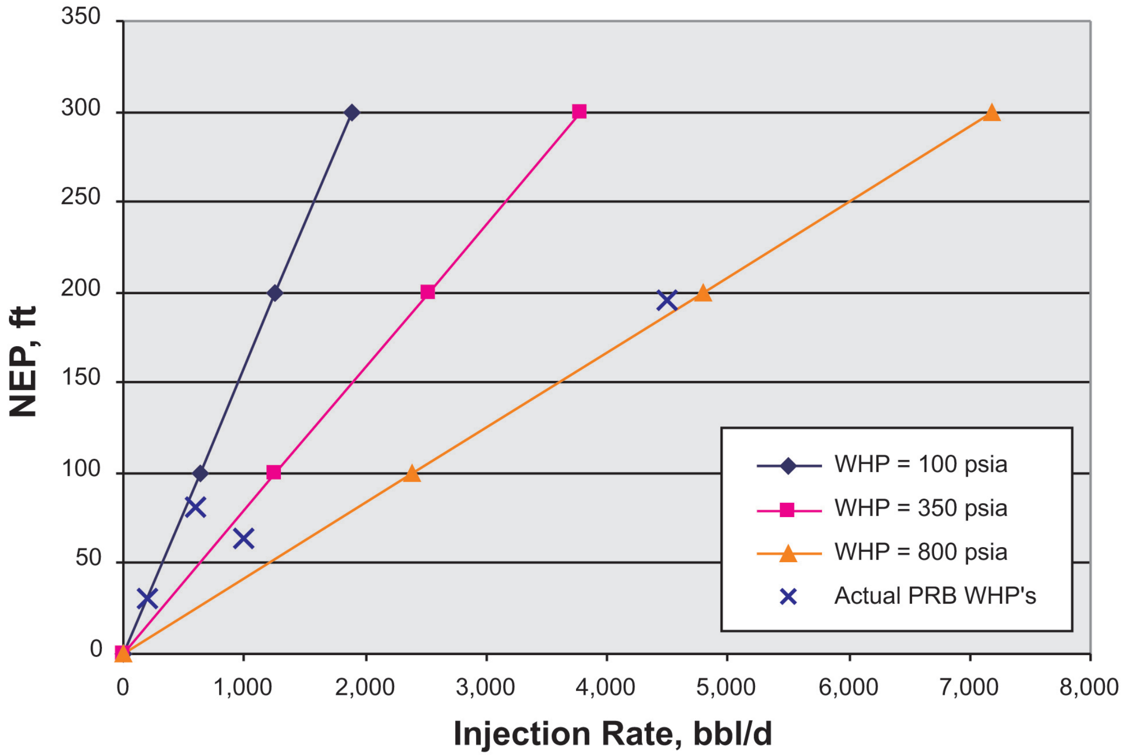

Figure 8. Expected water injection rates vs. zone thickness and wellhead pressure.

Water Volume Expected Performance

The expected volume of water that can be disposed into the Fort Union sands is not adequately known. The four referenced disposal wells have been active since early 2005 for periods from 2 to 16 months, and have injected water volumes from 36,000 barrels (bbl) to over 600,000 bbl. The wellhead rates and pressures are reported to have not changed appreciably since injection began, indicating that formation water is moving outward from the wellbores to distances beyond a ½-mile radius in some instances (personal communication, Dwayne Zimmerman, Nance Petroleum Corporation, 2006). The Fort Union sands are water-saturated, and injection of more water displaces the native water away from the injection point. Eventually the displacement wave will reach a structural or stratigraphic barrier, or the radial distance will become great enough to cause an appreciable friction pressure due to the long, tortuous flow path. Water is relatively incompressible, and when the system becomes full, the pressure will increase significantly with added injection. A pressure limit is reached when the bottom-hole injection pressure reaches the fracture gradient. The Fort Union fracture gradient is estimated to be about 0.70 psi/ft. This would equate to a wellhead pressure of about 1,250 psia at a depth of 2000 ft. A fluid-filled volume limit will eventually be reached in all such disposal wells, but current actual results show that water is steadily moving away from the injection points.

Assuming the aquifer reservoir is eventually a closed (i.e., sealed) container, then pressure response will be governed by the compressibility relationship

$$C_e = C_w + C_r = \left(\frac{1}{V_r}\right)\left(\frac{\Delta V}{\Delta P}\right),$$

and injection rate will diminish continuously as aquifer pressure increases. The following definitions apply to the compressibility relationship: C_e is total effective compressibility, psi^{-1}; C_w is water compressibility, psi^{-1}; C_r is rock compressibility, psi^{-1}; V_r is reservoir volume, bbl; ΔV is incremental injected water volume, bbl; and ΔP is reservoir pressure increase, psi.

Injection System Design

Wellbore Design

The design assumption is that all available Fort Union sand intervals will be completed in a disposal wellbore, to a total depth of 2000 ft. If new casing is installed and properly cemented to the surface, the casing can be used as the injection conduit directly to the disposal zones. The use of a 4-in outside diameter (OD) nominal casing size will accommodate a flow rate of over 10,000 bbl/d within an accepted friction limit of 40 psi/1000 ft of pressure loss. Larger casing, such as 5½-in OD or 7-in OD diameters, will have the capacity for higher injection rates and lower friction pressures. If existing wellbores are used for disposal, it may be advisable to protect the casing from undue pressure or corrosion and install tubing and a packer for water injection. Both designs will be considered with examples.

For an example of a new well, a 7-in OD, 23 lb/ft, K-55, STC oil well casing is a common pipe to run for large flow capacity and adequate strength factors. The casing should be cemented completely from TD to surface, typically inside a 12¼-in to 8¾-in drilled hole, and centralized across the disposal zones from 2000 ft to 1500 ft. The 7-in OD casing should be installed inside a section of surface casing, such as a 9⅝-in OD, 36 lb/ft, K-55, STC oil well casing set below the surface gravels and aquifers at approximately 350 ft depth and also cemented back to the surface. Appendix A contains a schematic of a typical 7-in OD casing wellbore design. Appendix B includes typical cementing designs for the 9⅝-in OD surface casing and the 7-in OD casing installations. A cement bond log should be run inside the 7-in OD casing to verify the cement integrity for isolating the various disposal zones. Completion of the well should be performed with wireline-conveyed jet perforations, at four shots per foot density, and 60°–90° shot phasing. A large entrance-hole diameter should be used, greater than 0.4 in, with medium shot penetration distance, greater than 12-in API test length. Well stimulation should not be required unless skin damage was developed during drilling and cementing. A water pump-in rate test would verify the injectivity, and if necessary breakdown of the perforations could be performed with ball sealers or diverting material. Water disposal could take place directly into the casing with gauges to monitor pressure and flow rate. Regulatory Underground Injection Control (UIC) injection permits require periodic pressure integrity tests of the 7-in casing every 5 years, at which times a retrievable bridge plug could be run on wireline to easily perform the test.

For an existing well with old casing, or when there is a need to protect the casing from injected fluid, tubing could be run with a packer set above the desired injection zones. Common oil well tubing sizes are 2⅜-in OD, 2⅞-in OD, and 3½-in OD, with designs based on the casing size and desired injection rates. The friction pressure loss from water flow down tubing should not exceed 40 psi/1000 ft. Maximum flow rates at this criteria limit are as follows (table 4; Brown and Coberly, 1960).

Table 4. Maximum flow rates at less than 40 psi/1000 ft

Tubing Size	Maximum Flow Rate
2⅜-in OD, 4.7 lb/ft, J-55, EUE	2,300 bbl/d
2⅞-in OD, 6.5 lb/ft, J-55, EUE	3,900 bbl/d
3½-in OD, 9.3 lb/ft, J-55, EUE	6,500 bbl/d

At the Fort Union sandstone depths a tension set packer is advisable (Baker “AD-1” or “J-Lok” types). The injection pressures below the packer help to ensure a positive seat, and tubing stretch changes due to pressure differentials or injecting of cold water act to increase the tension on the packer. UIC integrity tests can be performed easily by pressuring the tubing-casing annulus.

Injection Water Handling Design

The primary concerns for handling CBM water for re-injection are to remove all fine solid particles and prevent the entry of oxygen into the water. Fine solids can be carried from the coalbeds and producing wellbores in the water stream. These solids can cause injection pump wear and plugging of the down-hole disposal perforations. Solids removal is usually effective with ample settling time in a quiet

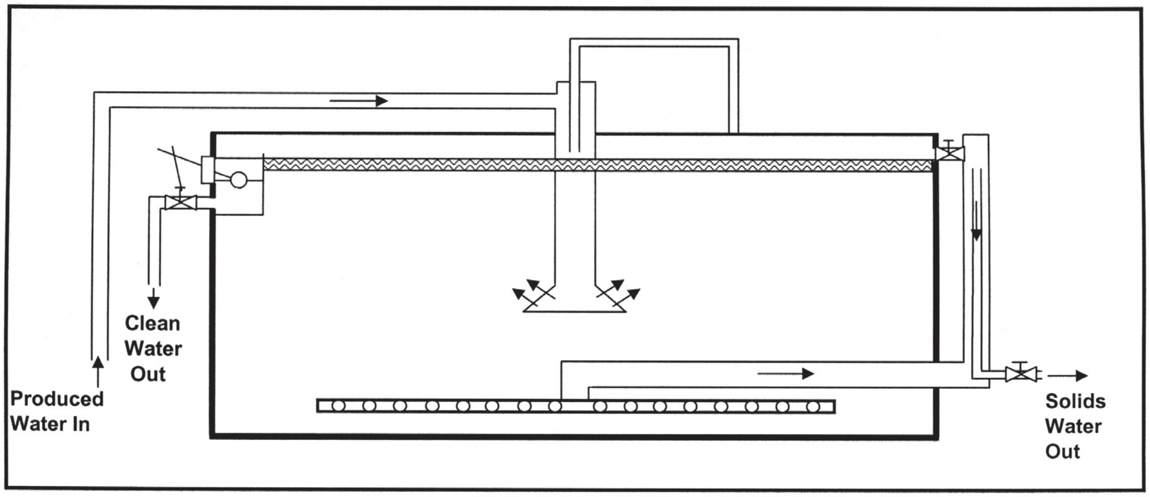

Figure 9. Skimmer and sedimentation tank.

tank (fig. 9; Rose and others, 2001). In cases where adequate settling time is not practical, the use of cartridge or bag type filters may be considered (fig. 10; Rose and others, 2001).

The entry of air (oxygen) into the disposal water can have serious effects from oxygen-iron corrosion (rusting and rust particles) and increased bacterial action. The preferred treatment is to prevent oxygen entry by keeping the entire water system at a positive pressure to atmosphere. This requires monitoring to prevent system leaks, not allowing open production well casings, and providing positive gas blankets on all water tanks. A typical gas blanket design is shown in figure 11 (Rose and others, 2001).

Injection Pump Design

Various types and sizes of pumps are used for injection systems, depending on the required rates and pressures, available power sources, initial purchase and maintenance costs, and familiarity of field personnel with pump operations. For higher pressure systems, a positive displacement type pump, such as a plunger pump, is a common choice. For lower pressure systems, a centrifugal type pump is often used. A currently popular pump type for use in the lower pressure ranges, such as expected in CBM water disposal, is an Electric Submersible Pump (ESP), installed either horizontally or vertically.

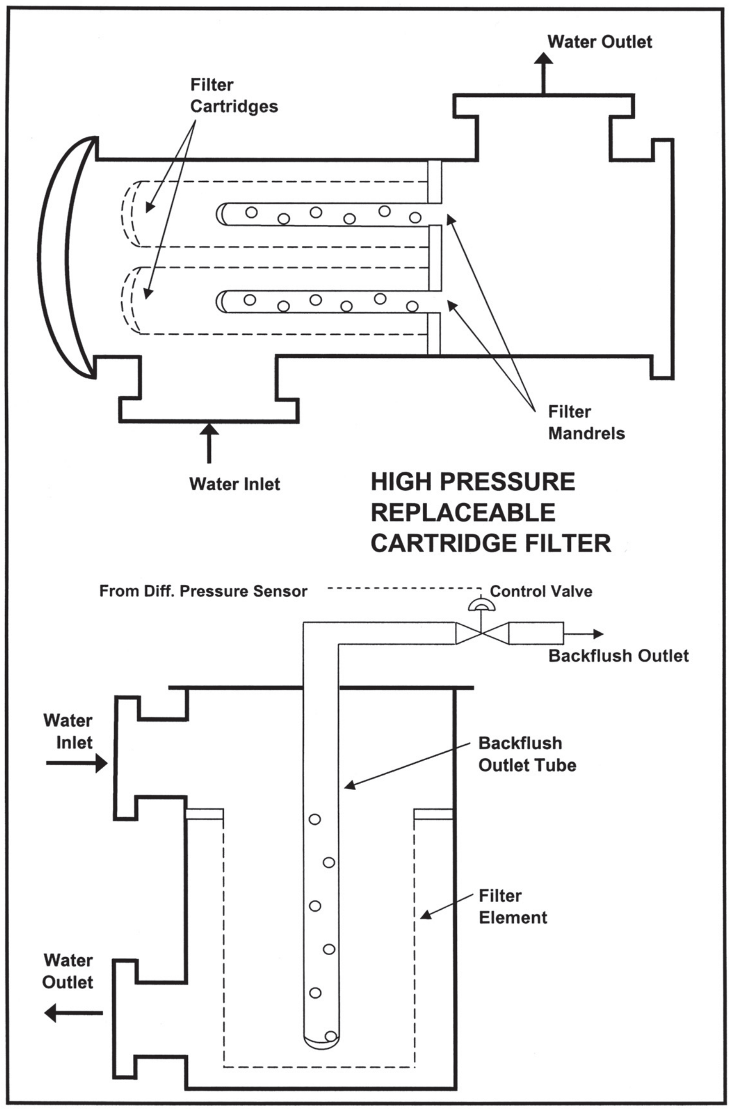

Figure 10. Cartridge type filters.

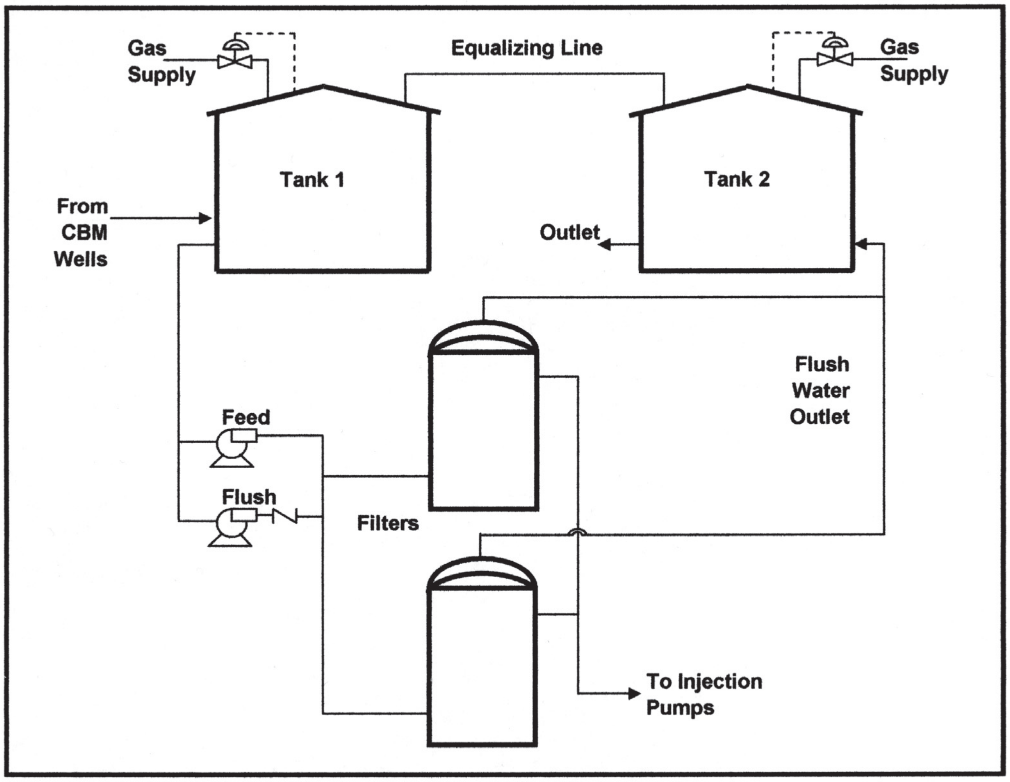

Figure 11. Gas blanket design example.

ESPs are also frequently used to lift water from CBM wells and are frequently operated and maintained in the adjacent field areas.

All pumps, both PD and centrifugal, require an adequate fluid pressure at the suction inlet, to prevent cavitation and mechanical damage. Pump manufacturers will provide information for the minimum required suction pressure, known as Net Positive Suction Head (NPSH). The required NPSH is a function of piping diameter and length, fluid properties, pump type, and water level height above the pump suction (fig. 12; Rose and others, 2001).

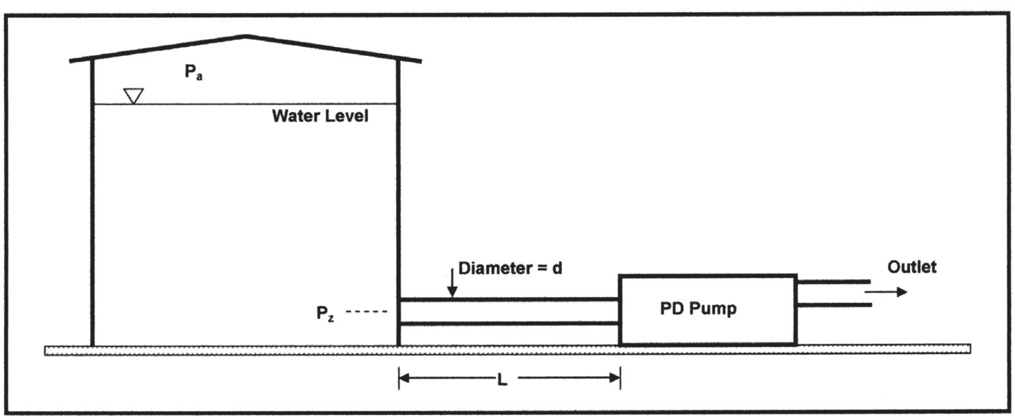

Figure 12. Typical water pumping system.

SUMMARY AND CONCLUSIONS

CBM development in the Paleocene Fort Union Formation in the Powder River Basin is currently one of the most active gas plays in the United States. Most of the CBM development in the Powder River Basin is in coalbeds of the Tongue River Member of the Fort Union Formation. The Fort Union Formation is divisible into three members: the Tullock, Lebo, and Tongue River, in ascending order.

Gas in coalbeds is trapped by hydrodynamic pressure; therefore, gas production requires a reduction in water pressure in order to release the gas held in the coal. This pressure reduction is achieved by pumping relatively large volumes of water from coalbed reservoirs.

CBM-produced water in Montana is of sufficiently good quality for domestic and livestock uses, but it has high SAR values, making it unusable for irrigation for most of the clay soils in the area. Consequently, disposal options, such as re-injection, must preserve beneficial use while not degrading surface waters that are used for irrigation.

The focus of this research was to identify specific potential injection targets. A complicating factor for disposal by injection is that potential shallow injection zones are water-saturated. In addition, injectivity in these zones is not as great as in well-known deep injection zones, such as limestone beds in the Madison Group. Therefore, a combination of water disposal methods, including surface discharge, infiltration ponds, direct agricultural and domestic use, treatment, and injection will probably yield the most feasible disposal plans and a balance between environmental and economic constraints.

Channel sandstones are probably the best targets for injection because they have more favorable porosity and permeability and because injecting into coalbeds may result in conflicts with future CBM development. Six channel sandstone units were identified in the Tongue River Member of the Fort Union Formation, informally named 'A' through 'F' in ascending order. The paleo-drainage patterns for each of these six channel systems are very similar, which may be due to similar paleogeography through time, but also suggests that there was paleo-structural control on the channel systems. It is clearly evident from isopach maps that the channels are widely distributed and that potential injection targets will not be available in every location where an injection well is desired. In other words, injection is not technically feasible in all locations regardless of cost.

Because of the uncertainty inherent in the mapping of channels, the design of an injection well was based on an existing well with excellent channel sandstone development instead of a location based solely on channel isopach mapping. The type well chosen was the International Nuclear Corporation, State MT Minerals #1, in sec. 28, T. 9 S., R. 44 E., Big Horn County, Montana, which encountered well-developed channel sandstones in the 'A,' 'C,' and 'D' intervals and has good resistivity and sonic logs.

Coalbed-methane well production in the Powder River Basin typically starts with significant water rates, in excess of 200 bbl/d, and low gas rates. Over a period of time the water rates decrease to small volumes, and gas rates increase to their maximum values as water is removed from the coal system, allowing gas to desorb in the decreasing pressure environment. This typical well performance requires the handling of variable water volumes, and supports the central gathering of water from multiple wells for combined disposal or treatment.

Considering subsurface re-injection of the produced water as the disposal method, porous and permeable channel sandstones are present in the Tongue River Member for re-injection of significant volumes of water. Data from four studied active water disposal wells completed in the Wasatch and Fort Union channel sandstones show reasonable injection rates (200–4500 bbl/d) depending on formation sand thicknesses completed, and well pressures that do not exceed an estimated fracture gradient of 0.70 psi/ft. Disposal well histories over a period of 2–16 months indicate no change or increase in well pressures for cumulative injected volumes of 36,000–600,000 barrels of water. These data correspond to an average effective formation permeability of 31.5 md, which does not require stimulation treatment to achieve reasonable injection rates.

Well completion designs for new drilled injection wells of ±2000-ft depth would reasonably assume injection down production casing. The casing should be cemented fully to surface and perforated with at least four holes per foot in water sands totaling from 100 ft to 300 ft in net pay thickness. Existing recompleted disposal wells should consider installation of tubing and packers to protect the casing, but friction pressure losses would decrease the well injection capacity. Surface treatment of the produced water would consist of oxygen (air) elimination and removal of fines and solids through gravity tank settling or filtering prior to pressurizing for well disposal.

ACKNOWLEDGMENTS

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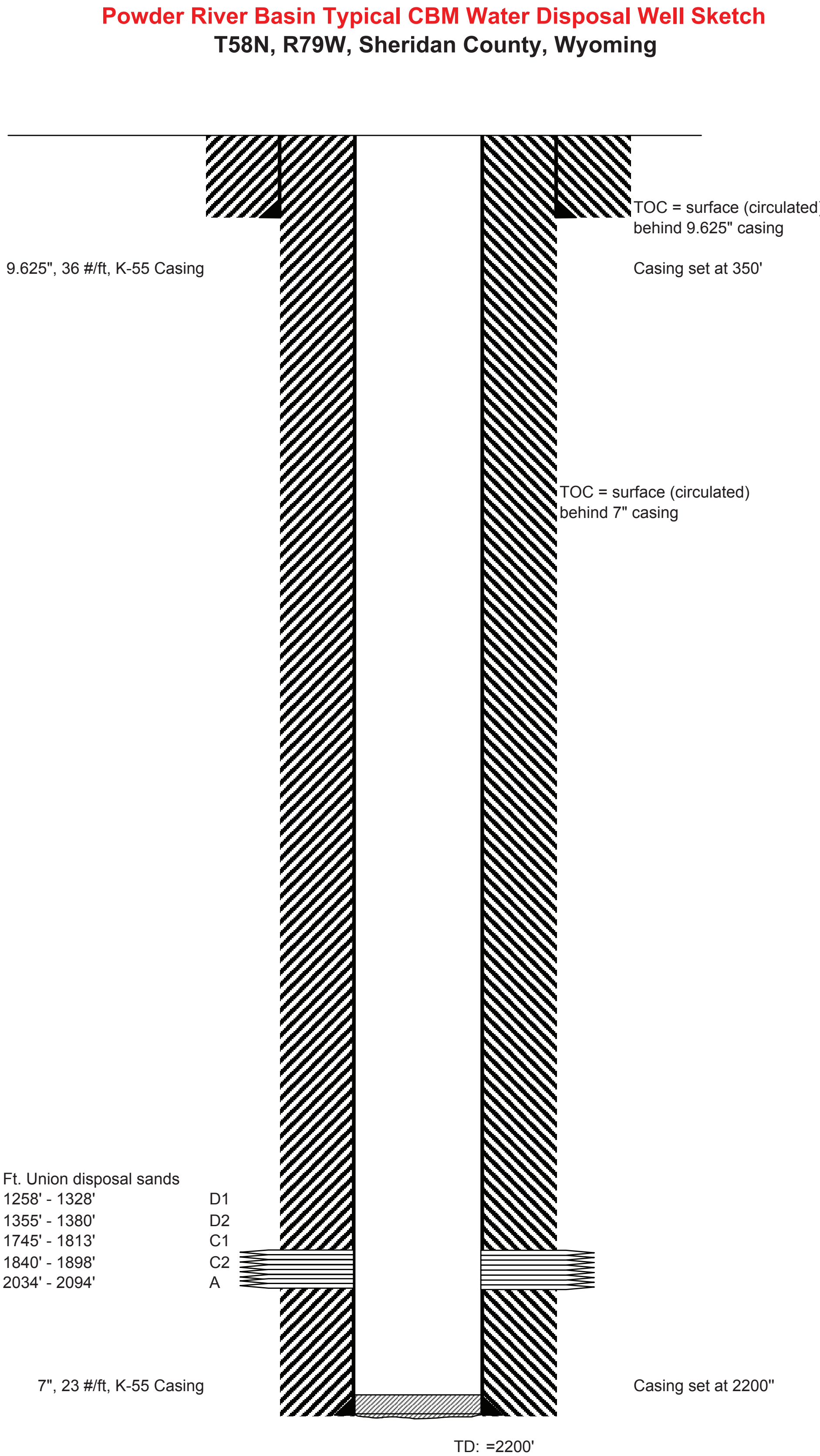
APPENDIX A


Powder River Basin Typical CBM Water Disposal Well Sketch
T58N, R79W, Sheridan County, Wyoming
TOC = surface (circulated)
behind 9.625" casing
9.625", 36 #/ft, K-55 Casing
Casing set at 350'
TOC = surface (circulated)
behind 7" casing
Ft. Union disposal sands
1258' - 1328' D1
1355' - 1380' D2
1745' - 1813' C1
1840' - 1898' C2
2034' - 2094' A
7", 23 #/ft, K-55 Casing
Casing set at 2200"
TD: =2200'

APPENDIX B

TECHNICAL DISCUSSION

SOURCE: Haliburton Energy Services, Evansville, WY, July 2006

Cementing Best Practices

1. *Cement quality and weight:* You must choose a cement slurry that is designed to solve the problems specific to each casing string.

2. *Waiting time:* You must hold the cement slurry in place and under pressure until it reaches its initial set without disturbing it. A cement slurry is a time-dependent liquid and must be allowed to undergo a hydration reaction to produce a competent cement sheath. A fresh cement slurry can be worked (thickening or pump time) as long as it is in a plastic state and before going through its transition phase. If the cement slurry is not allowed to transition without being disturbed, it may be subjected to changes in density, dilution, settling, water separation, and gas cutting that may lead to a lack of zonal isolation and possible bridging in the annulus.

3. *Pipe movement:* Pipe movement may be one of the single most influential factors in mud removal. Reciprocation and/or rotation mechanically breaks up gelled mud and changes the flow patterns in the annulus to improve displacement efficiency.

4. *Mud properties (for cementing)*:

   Rheology:

   Plastic Viscosity (PV) < 15 centipoise (cp)

   Yield Point (YP) < 10 lb/100 ft^2

   These properties should be reviewed with the Mud Engineer, Drilling Engineer, and Company Representative(s) to ensure no hole problems are created.

   Gel Strength:

   The 10-second/10-minute gel strength values should be such that the 10-second and 10-minute readings are close together or flat (i.e., 5/6). The 30-minute reading should be less than 20 lb/100 ft^2. Sufficient shear stress may not be achieved on a primary cement job to remove mud left in the hole if the mud were to develop more than 25 lb/100 ft^2 of gel strength.

   Fluid Loss:

   Decreasing the filtrate loss into a permeable zone enhances the creation of a thin, competent filter cake. A thin, competent filter cake created by a low fluid loss mud system is desirable over a thick, partially gelled filter cake. A mud system created with a low fluid loss will be more easily displaced. The fluid loss value should be < 15 cc (ideal would be 5 cc).

5. *Circulation:* Prior to cementing circulate full hole volume twice, or until well-conditioned mud is being returned to the surface. There should be no cutting in the mud returns. An annular velocity of 260 ft per minute is optimum (SPE/IADC 18617), if possible.

6. *Flow rate:* Turbulent flow is the most desirable flow regime for mud removal. If turbulence cannot be achieved pump at as high a flow rate as can practically and safely be used to create the maximum flow energy. The highest mud removal is achieved when the maximum flow energy is obtained.

7. *Pipe centralization:* Cement will take the path of least resistance; therefore, proper centralization is important to help prevent the casing from contacting the borehole wall. A minimum standoff of 70% should be targeted for optimum displacement efficiency.

8. *Rat hole:* A weighted viscous pill placed in the rat hole prior to cementing will minimize the risk of higher density cement mixing with lower density mud when the well is static.

9. *Top and bottom plugs:* A top and bottom plug are recommended to be run on all primary casing jobs. The bottom plug should be run after the spacer and ahead of the first cement slurry.

10. *Spacers and flushes:* Spacers and/or flushes should be used to prevent contamination between the cement slurry and the drilling fluid. They are also used to clean the wellbore and aid with bonding. To determine the volume, either a minimum of 10 minutes contact time or 1000 ft of annular fill, whichever is greater, is recommended.

Calculations 9 5/8" Surface Casing Cement

Spacer:	
Total Spacer	= 112.29 ft^3
	= 20.00 bbl
Cement : (350.00 ft fill)	
350.00 ft * 0.3132 ft^3/ft * 100 %	= 219.23 ft^3
Primary Cement	= 219.23 ft^3
	= 39.05 bbl
Shoe Joint Volume: (40.00 ft fill)	
40.00 ft * 0.4419 ft^3/ft	= 17.68 ft^3
	= 3.15 bbl
Tail plus shoe joint	= 236.91 ft^3
	= 42.19 bbl
Total Tail	= 132 sks
Total Pipe Capacity:	
350.00 ft * 0.4419 ft^3/ft	= 154.66 ft^3
	= 27.55 bbl
Displacement Volume to Shoe Joint:	
Capacity of Pipe - Shoe Joint	= 27.55 bbl - 3.15 bbl
	= 24.40 bbl

Job Recommendation 9 5/8" Surface Casing Cement

Fluid Instructions

Fluid 1: Water Based Spacer

Water Spacer	Fluid Density:	8.34 lbm/gal
42 gal/bbl Fresh Water (Base Fluid)	Fluid Volume:	20 bbl

Fluid 2: Rockies LT

Rockies LT	Fluid Weight	13.50 lbm/gal
0.125 lbm/sk Poly-E-Flake (Additive Material)	Slurry Yield:	1.80 ft^3/sk
0.25 lbm/sk Kwik Seal (Additive Material)	Total Mixing Fluid:	9.33 Gal/sk
	Top of Fluid:	0 ft
	Calculated Fill:	350 ft
	Volume:	42.19 bbl
	Calculated Sacks:	131.61 sks
	Proposed Sacks:	140 sks

Fluid 3: Water Based Spacer

Displacement	Fluid Density:	8.34 lbm/gal
	Fluid Volume:	24.40 bbl

Job Procedure 9 5/8" Surface Casing Cement

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Down-hole Volume
1	Spacer	Spacer	8.3	3.0	20 bbl
2	Cement	Primary Cement	13.5	3.0	140 sks
3	Spacer	Displacement Fluid	8.3	3.0	24.40 bbl

Job Information 7" Production Casing Cement

7" Production Casing	0 - 2000 ft (MD)
Outer Diameter	7.000 in
Inner Diameter	6.366 in
Linear Weight	23 lbm/ft
8 3/4" Open Hole Section	350 - 2000 ft (MD)
Inner Diameter	8.750 in
Job Excess	100 %
9 5/8" Surface Casing	0 - 350 ft (MD)
Outer Diameter	9.625 in
Inner Diameter	9.001 in
Linear Weight	32.30 lbm/

Calculations 7" Production Casing Cement

Spacer:	
Total Spacer	= 112.29 ft^3
	= 20.00 bbl
Cement : (1500.00 ft fill)	
350.00 ft * 0.1746 ft^3/ft * 0 %	= 61.12 ft^3
1150.00 ft * 0.1503 ft^3/ft * 100 %	= 345.76 ft^3
Total Lead Cement	= 406.88 ft^3
	= 72.47 bbl
Sacks of Cement	= 153 sks
Cement : (500.00 ft fill)	
500.00 ft * 0.1503 ft^3/ft * 100 %	= 150.33 ft^3
Tail Cement	= 150.33 ft^3
	= 26.77 bbl
Shoe Joint Volume: (40.00 ft fill)	
40.00 ft * 0.221 ft^3/ft	= 8.84 ft^3
	= 1.57 bbl
Tail plus shoe joint	= 159.17 ft^3
	= 28.35 bbl
Total Tail	= 85 sks
Total Pipe Capacity:	
2000.00 ft * 0.221 ft^3/ft	= 442.07 ft^3
	= 78.74 bbl
Displacement Volume to Shoe Joint:	
Capacity of Pipe - Shoe Joint	= 78.74 bbl - 1.57 bbl
	= 77.16 bbl

Job Recommendation 7" Production Casing Cement

Fluid Instructions
Fluid 1: Water Based Spacer
Water Spacer — Fluid Density: 8.34 lbm/gal
42 gal/bbl Fresh Water (Base Fluid) — Fluid Volume: 20 bbl

Fluid 2: RMCBM 3
Standard Cement
Fluid Weight 12 lbm/gal
Slurry Yield: 2.65 ft^3/sk
Total Mixing Fluid: 15.58 Gal/sk
Top of Fluid: 0 ft
Calculated Fill: 1500 ft
Volume: 72.47 bbl
Calculated Sacks: 153.42 sks
Proposed Sacks: 160 sks

Fluid 3: RMCBM 3
Standard Cement
Fluid Weight 13.50 lbm/gal
Slurry Yield: 1.88 ft^3/sk
Total Mixing Fluid: 9.82 Gal/sk
Top of Fluid: 1500 ft
Calculated Fill: 500 ft
Volume: 28.35 bbl
Calculated Sacks: 84.53 sks
Proposed Sacks: 90 sks

Fluid 4: Water Based Spacer
Displacement
Fluid Density: 8.34 lbm/gal
Fluid Volume: 77.16 bbl

Job Procedure 7" Production Casing Cement

Detailed Pumping Schedule

Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Estimated Avg Rate bbl/min	Down-hole Volume
1	Spacer	Spacer	8.3	3.0	20 bbl
2	Cement	Lead Cement	12.0	3.0	160 sks
3	Cement	Tail Cement	13.5	3.0	90 sks
4	Spacer	Displacement Fluid	8.3	3.0	77.16 bbl