Chapter 7

Distribution of Fluids and Pressures in the Wind River Basin, Wyoming

By Philip H. Nelson and Joyce E. Kibler

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Chapter 7 of

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Distribution of Fluids and Pressures in the Wind River Basin, Wyoming

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Abstract

To examine the state of hydrocarbons and water in the Wind River Basin of Wyoming, the following data types are compiled and presented at the basin scale: fluid type, pressure, and temperature from drillstem tests; water salinity and cumulative hydrocarbon production from oil and gas wells; vitrinite reflectance data; and sonic well logs. The spatial distribution of produced fluids shows the nearly ubiquitous presence of mobile water, even in highly productive gas-charged formations. Sonic logs record a basinwide velocity decrease in the Lower Cretaceous Thermopolis Shale through the Upper Cretaceous Cody Shale that is attributed to a combination of paleo-overpressuring and present-day overpressuring. Pressure-elevation plots and mud weights reveal the presence of two large pressure compartments in the Madden area, one above the Waltman Shale Member of the Paleocene Fort Union Formation and the other below it. Temperature data reveal hot and cold spots around structures in the marginal parts of the basin where the Waltman Shale Member of the Fort Union Formation is absent. The highest temperature gradients are in the upper pressure compartment in the Madden area. Vitrinite reflectance data record little change with increasing depth throughout much of the geologic section in shallow parts of the basin and a steady increase of log (R_o) with depth in the deep parts of the basin. The varied distribution of fluids, pressure, and temperature reflect the complex history of subsidence, thrusting, hydrocarbon generation, water migration, and uplift in and marginal to this large, asymmetric intermontane basin.

Introduction

An assessment of undiscovered hydrocarbon resource requires an understanding of the disposition of oil and gas within the geologic setting of a basin. In the unexplored sectors of a basin, where the location and size of hydrocarbon accumulations are unknown, an assessment proceeds by combining what is known regarding the geological framework and parameters governing the generation and movement of oil and gas. Such an exercise is described at length for the Cretaceous-Lower Tertiary Composite Total Petroleum System in the Wind River Basin by Johnson and others (Chapter 4, this CD-ROM). This study, which examines some of the fluid-related parameters in detail, was conducted as part of the U.S. Geological Survey's assessment of undisovered oil and gas resources of the Wind River Basin in 2005.

Oil and gas wells in the Wind River Basin, Wyoming, are predominantly associated with structure, whether anticlines or more subtle flexures (fig. 1). The association between major thrusting and oil and gas fields is clearest along three major northwest-trending thrust fault systems transecting the basin (fig. 1). Some gas accumulations in the basin lack the typical attributes of conventional accumulations, in that fluid contacts cannot be determined and controls on gas confinement cannot be discerned. Such gas systems are referred to as basin-centered gas. In these gas systems, much of the gas production is from rocks with low porosities and permeabilities and successful production presents an engineering challenge. Large quantities of water are produced with gas in some accumulations; in others, the water-gas ratio is relatively low. Johnson and others (Chapter 4, this CD-ROM) argue that fractures play a major role in both the distribution and production of basin-centered gas in the Wind River Basin.

The purpose of this report is to present data related to the distribution of hydrocarbons and water at a basinwide scale, with particular emphasis on data bearing on deep gas accumulations. Three parameters of interest are from drillstem tests: fluid type, pressure, and temperature. Other parameters of interest are vitrinite reflectance, water salinity, sonic logs showing evidence of present-day pressure and paleopressure, cumulative fluid production, water-gas ratios, and the estimated ultimate recovery of gas. The Waltman Shale Member of the Paleocene Fort Union Formation appears to act as a barrier to vertical migration of water and hydrocarbons, therefore its thickness and lateral extent are included in this data presentation. Stratigraphic relations are shown in figure 2.

Although many publications report pressure, temperature, and fluid type in the context of describing the geology of a productive area or a portion of a basin, basin-scale presentations of fluid-related properties are rare, and there is no standard way to present the data. Several methods exist for relating point data such as fluid type and pressure to three-dimensional space: (1) contour maps of a single parameter

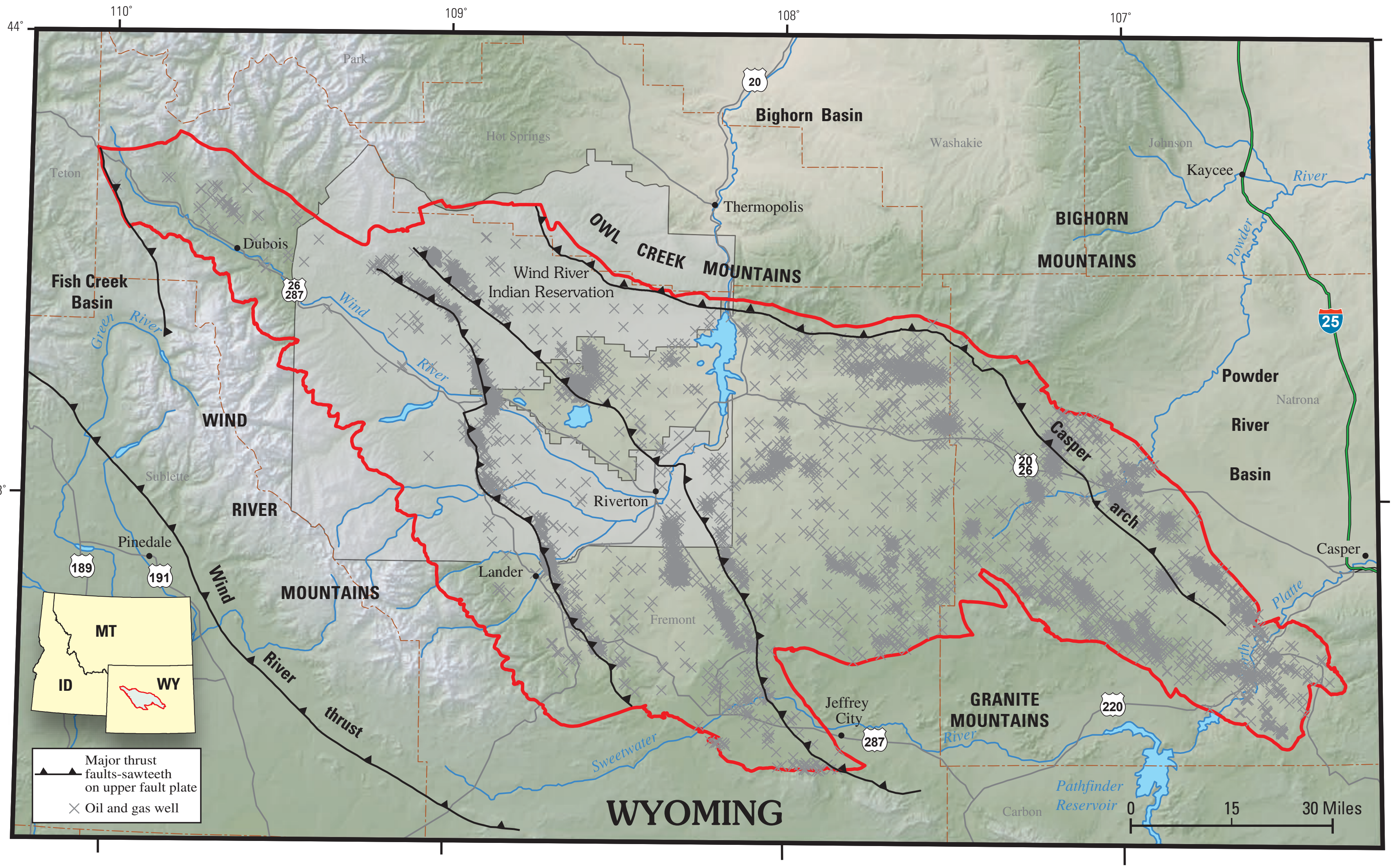


Figure 1. Map of Wind River Basin Province (red line) showing distribution of all drilled wells

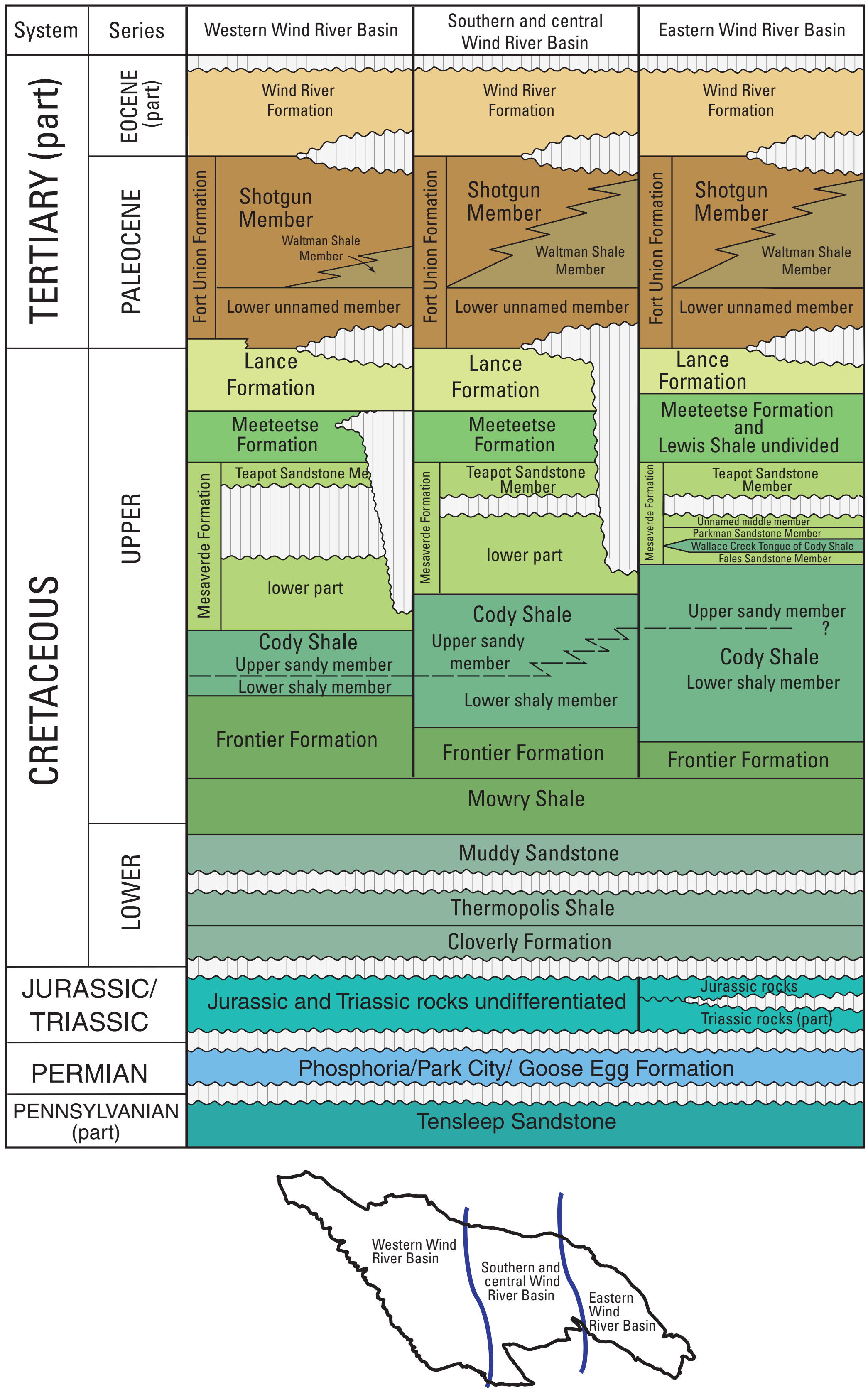


Figure 2. Generalized stratigraphic chart of Pennsylvanian (part) through lower Tertiary rocks in the Wind River Basin Province, central Wyoming. Time spans and thicknesses not shown to scale. Hatching indicates time periods of erosion or nondeposition; wavy line represents unconformity. Inset map shows basin subdivisions.

(for example, depth to a particular horizon), (2) maps of points representing the maximum value or a range of a parameter in a well, (3) posting and contouring parameter values or plotting well logs on stratigraphic or structural cross sections, (4) three-dimensional views, and (5) arrays of plots connected to maps. The latter method is used extensively in this report to graphically portray depth-dependent variations of pressure, temperature, vitrinite reflectance, well-log character of the Waltman Shale Member of the Fort Union Formation, sonic logs, and estimated ultimate recovery of gas as a function of location within the basin.

Pressures and Fluid Types from Drillstem Tests

Pressures from drillstem tests (DSTs) are plotted as a function of elevation for 22 selected areas in Wind River Basin, with fluid type denoted by a symbol (pl. 1) and shut-in and flowing pressures shown as horizontal needles (pl. 2). Most plot scales range from +5,000 to -10,000 feet (ft) in elevation and 0 to 10,000 pounds per square inch (psi) in pressure. However, deeper wells in northern areas of the basin require elevation scales extending to -15,000 ft and pressure scales exceeding 10,000 psi. The pressure and fluid data are taken from a number of wells within each area and are plotted as a function of elevation with respect to mean sea level (msl) rather than depth, thus removing the effect of well-to-well topographic variation and permitting assessment of fluid gradients across a multiwell area (Forster and Horne, 2005).

To the right of each pressure-elevation plot on plates 1 and 2 is a plot of a gamma-ray log and selected formation boundaries from a well as centrally located within an area as possible (no log was available from the Boone Dome area). Due to basin structure, which is represented on an inset map (pls. 1 and 2) by contours on top of the Frontier Formation, the elevation of a formation top varies across each area, so a given pressure point could fall within, above, or below the corresponding formation shown with the gamma-ray log. The potential mismatch is greatest in those areas encompassing the greatest structural relief, such as the Squaw Butte and East Riverton Dome areas.

A pressure plotted in plate 1 represents the greatest value of all flowing and shut-in pressures in a drillstem test, although the shut-in pressure generally exceeds the flowing pressure. A pressure plotted in plate 2 is either the greatest of all shut-in pressures or the greatest of all flowing pressures. The needle plots in plate 2 are not additive; a red needle terminating at 1,000 psi superposed on a black needle terminating at 2,200 psi indicates a maximum flowing pressure of 1,000 psi and a maximum shut-in pressure of 2,200 psi.

Determination of Fluid Types and Ratios

The symbols for fluids (pl. 1) reflect ratios rather than absolute amounts of fluids recovered in a test. The fluid contents and ratios were obtained from descriptions of drillstem tests by the Wetterhorn Company (2004) as illustrated by the following three examples:

(1) Water only (blue diamonds) would result from the following description: 1,052 ft of water in drill pipe.

(2) Gas and oil only (red circles) would result from the following descriptions (rec, recovered; sli GCM, slightly gas-cut mud; CFG, cubic ft of gas; GTS, gas-to-surface; MCFD, thousand cubic ft of gas per day; cond, condensate): (1) rec 90' sli GCM; (2) rec 52 CFG in sampler; (3) GTS and GCM; (4) GTS @ 162 MCFD; (5) Sampler: 5 CFG & cond.

(3) If both hydrocarbons and water were recovered, then fluid ratios (yellow triangles, orange squares, red triangles) are computed using conversion factors established by the Wetterhorn Company (2004). As an example, consider the following description of a drillstem test (WCM, water-cut mud; G&WCM, gas and water-cut mud; MCW, mud-cut water): 49013050020000 Pan American Tribal R1, Test #3, 3085-3185 ft, Fort Union, Rec 248 ft WCM, 124 ft G&WCM, 2218 ft MCW w gas pockets.

Parsing of this description follows:

- 248 ft of water-cut mud converts to 79 percent mud and 21 percent water.
- 124 ft of gas-cut, water-cut mud converts to 65 percent mud, 17 percent gas, and 17 percent water.
- 2,218 ft of mud-cut water with gas converts to 65 percent water, 17 percent mud and 17 percent gas.

Fluid amounts and ratios are computed as follows:

- Total ft of water = 0.21*248 + 0.17*124 + 0.65*2218 = 1514
- Total ft of gas = 0.17*124 + 0.17*2218 = 398
- Gas to water ratio = 398 / (1514 + 398) = 0.21
- Total ft of oil = 0.0
- Ratio of oil + gas to water = 0.21

Shut-in and Flowing Pressures

Shut-in pressure is measured during a shut-in period that follows an open-flow period in a drillstem test. Shut-in pressure is expected to be less than the true formation pressure, especially in low-permeability formations where impractically long shut-in times are required to reach true formation pressure. Most drillstem tests utilize two shut-in periods, with shut-in pressure recorded at the end of each period. We used the maximum value of the two shut-in pressures.

Flowing pressure is measured during the open-flow period in a drillstem test, as fluid enters the wellbore and fills the drill pipe or sample chamber. Flowing pressure is generally recorded at the beginning and end of a flow period and many drillstem tests utilize two flow periods, therefore there can be as many as four values of flowing pressure recorded; we used the maximum value of flowing pressure. Because flowing pressure is not always reported, fewer pressures appear on plate 2 than on plate 1.

The plots in plate 2 show the ratio of flowing to shut-in pressure as a function of elevation in each of the areas outlined on the basin map. Shut-in pressure is plotted as a horizontal black needle and flowing pressure as a horizontal red needle. For example, on the plot for the Muddy Ridge area (pl. 2), flowing pressures typically range from 5 to 15 percent of shut-in pressures. On the plot for the Madden area, in contrast, flowing pressures are typically 70 to 100 percent of shut-in pressures, much higher than any of the other areas. In those few cases where only a red needle is visible, the flowing pressure equals or exceeds the shut-in pressure.

In most areas, the maximum (uncorrected) pressure represented by the right-hand edge of the needles tracks the 0.433 psi/ft gradient, which is referenced to 0 psi at the mean elevation of the wells in that area. Assuming that the maximum shut-in pressure is a reasonable measure of formation pressure, then most of the Wind River Basin is normally pressured, or in some areas slightly overpressured at elevations above -5,000 ft msl. Again, the Madden area is an exception: pressure is significantly greater than hydrostatic below the base of the Waltman Shale Member at 0 ft msl.

The ratio of red to black can be considered an indicator of the capability of a formation to produce fluids. If pressure does not drop much as fluids are produced (the red to black ratio is high), then production is expected to continue for a relatively long time. (Analogy: the water tower is quite full and the withdrawal pipe is not inappropriately large.) On the other hand, if the flowing pressure is small compared to shut-in pressure (the red to black ratio is low), then sustained production cannot be expected unless the well is stimulated. (Drillstem tests are normally conducted prior to any well stimulation.) Dolan and others (1957), in their early paper on field interpretation of drillstem tests suggested that the normalized difference between formation pressure and flowing pressure is an indicator of wellbore damage – the greater the normalized pressure difference, the greater the wellbore damage. In the Wind River Basin, however, we expect low flowing-to-shut-in pressures to be due largely to low permeability rather than wellbore damage.

Observations

The Madden area is moderately overpressured (pressure-depth ratios of 0.5 to 0.6 psi/ft) from 0 to -9,000 ft and highly overpressured below -9,000 ft (pressure-depth ratios greater than 0.6 psi/ft; pls. 1 and 2). No other area is moderately or highly overpressured at elevations shallower than -7,000 ft. Sparse data in the north-central portion of the basin indicate that formations are highly overpressured at depth. As explained later, sonic logs also show that highly overpressured formations exist below the top of the Cody Shale. Fluid recovery types are mixed in the Madden area, are predominantly gas in the Bonneville, Deep Wildcats, Frenchie Draw, Garrison Draw, and Waltman-Bullfrog areas, and are a function of elevation in other areas (pl. 1). The fluid recovery symbols (pl. 1) show (1) a large percentage of gas recoveries in the Pavillion and Muddy Ridge areas at all elevations; (2) mixed fluid recoveries in the Madden area at all elevations; and (3) a large percentage of water recoveries from 0 to -3,000 ft in the Kirby Draw and Big Sand Draw area, from 1,200 to 2,000 ft in the Castle Garden area, and from 2,000 to -2,500 ft in the East Riverton Dome area.

Near the basin trough in the north-central part of the basin, where rocks are most deeply buried, the shallowest approximate elevations where pressures reach or exceed pressure-depth ratios of 0.6 psi/ft are in the Howard Ranch area at -11,000 ft, in the Madden area at -9,000 ft, in the Bonneville area at -7,000 ft, in the Deep Wildcats area at -12,000 ft, in the Frenchie Draw area at -7,200 ft, and in the Garrison Draw area at -8,000 ft. The pressure data are not numerous enough to define the top of high overpressure except in the Madden area where it is at -9,000 ft.

Moderate overpressure exists in the 0 to -9,000-ft elevation range within the Madden area. The dashed line shown on the Madden plot in plate 1 bounds much of the data in this elevation range, as noted by Forster and Horne (2005, fig. 21). The dashed line parallels the 0.433 psi/ft pressure gradient line but is offset from this normal hydrostatic gradient by 2,300 ft and 1,000 psi. No other area in the basin exhibits this pressure signature. Forster and Horne (2005) noted the absence of a water-free region; an elevated 0.433 psi/ft gradient can be interpreted in terms of preservation of pressure in an uplifted water-dominated volume that was once normally pressured.

The maximum shut-in pressure in the Madden area takes a second step increase at an elevation of about -9,000 ft msl, to pressure-depth ratios greater than 0.6 psi/ft. Again, the Madden area is the exception, as other areas show smaller pressure increases at depths greater than -5,000 to -6,000 ft msl, with pressure-depth ratios exceeding 0.5 psi/ft. Areas showing these increases (data are sparse) lie along the northern side of the basin where Tertiary and Cretaceous sediments are thickest; these are Sand Mesa, Howard Ranch, Bonneville, Deep Wildcats, Frenchie Draw, and Garrison Draw. The ratio of flowing pressure to shut-in pressure exceeds 0.5 in many of these deeper tests, due probably to the mild overpressure.

Underpressured areas cannot be positively identified because a pressure-depth ratio less than 0.433 psi/ft can be due to either low permeability or underpressure. However, clusters of pressure data with low gradients reveal intervals that may be underpressured (pl. 1). Such clusters are from (1) 1,500 to 2,200 ft in the Riverton Dome-Beaver Creek area, (2) 0 to 3,000 ft in the Kirby Draw-Big Sand Draw area, (3) 1,000 to 2,000 ft in the Muskrat area, (4) 4,200 to 0 ft in the Burnt

Wagon area, (5) -3,000 to -4,000 ft in the West Poison Spider area, and (6) -1,000 to -2,000 ft in the Boone Dome area.

Fluid Temperatures from Drillstem Tests

The temperature of fluids recovered on drillstem tests versus elevation are displayed on plate 3. Each data point represents the temperature of fluid recovered from the formation on a single drillstem test. The three lines represent temperature gradients of 1.2, 1.6, and 2.0 degrees Fahrenheit per 100 feet (°F/100 ft) of elevation change and converge to a temperature of 46°F at a surface elevation in the center of each area. Variations in topography across an area can result in a vertical displacement of a few hundred feet for a given temperature datum with respect to the gradient lines.

The temperatures shown in plate 3 are the temperatures of fluids produced from a formation as the fluids enter the sample chamber of the drillstem test equipment. Bottom-hole temperatures from well logs, on the other hand, are the temperatures of drilling mud recorded with a maximum-recording thermometer during a logging run. At a given depth in a well, the temperature of the formation fluid should be higher than the mud temperature because the mud is cooled as it circulates during drilling. This is substantiated by data in the Madden area, where drillstem temperatures (colored symbols) are greater than the bottom-hole logging temperatures (open gray circles). As a consequence, some analysts add a depth-dependent correction of around 30°F to bottom-hole temperatures reported on well logs (Pawlewicz, 1993) to better approximate the formation temperature. No correction was applied to the temperatures obtained from drillstem tests shown in plate 3.

The scatter in temperature at a given elevation in some plots is as great as 50°F. One might expect that some of the variation could be correlated with the type of fluid recovered (colored symbols designate the fluid mix obtained from a drillstem test) – drilling fluid (gray hexagons) might be at lower temperature than water, gas, or oil because of its short residence time within the formation. However, visual inspection of the plots does not reveal any systematic differences in temperature as a function of fluid type. Aside from any measurement errors, the scatter in temperatures could be due to true lateral variation across an area and (or) fluid migration along faults and fractures. An example of localized anomalous temperatures is in the Wallace Creek and North Grieve area, where seven data points with temperatures greater than 170°F and elevations between -4,000 and 0 ft lie to the right of the main data trend (pl. 3). These seven data points originate from wells in two areas each a few square miles in extent, one in the Wallace Creek field and the other in the North Grieve field. Temperatures from other wells in the area are markedly cooler than these two local hot spots.

The scatter in the temperature data, much of which is created by convecting fluids, creates a dilemma in representing the temperature gradients on a map. We chose to represent the gradient in each area by selecting a gradient through the main trend of the temperature data, ignoring high temperature and low temperature outliers. Ignoring the outliers, we observed substantial variations in temperature among different areas of the basin. Except for the westernmost parts of the basin, the areas with the highest temperature gradients are the Madden, Frenchie Draw, and Deep Wildcats areas, where the temperatures represent gradients of 1.6°F/100 ft and greater; some temperature gradients in the Madden area exceed 2.0°F/100 ft. In the Madden, Deep Wildcats, and Garrison Draw areas, the temperatures appear to increase at the top of the lower part of the Fort Union Formation and maintain a higher thermal gradient from that point downward than in the overlying formations. The Pavillion and Muddy Ridge areas display some of the lowest temperatures, represented by gradients of 1.3 and 1.2°F/100 ft, respectively. The lowest temperatures are in the Wallace Creek area, where the gradient is around 1.0°F/100 ft.

The contours of temperature gradient on the map in plate 3 capture these thermal gradient variations across the basin. The resulting contours are fairly smooth because the contours are based on average gradients within each of the 22 circled areas. A few “bulls-eye” contours include the high and low gradients previously discussed. Pawlewicz (1993) constructed a temperature gradient map of the Wind River Basin, using bottom-hole temperatures obtained from well logging runs and applying a temperature correction. Present on plate 3 map and Pawlewicz’s map are: (1) the high gradient in the Madden area, (2) a broad central area with relatively little change (ranging from 1.4 to 1.6 °F/100 ft on plate 3 map), and (3) high gradients in the Kirby Draw-Big Sand Draw area at the south edge of the basin. However, in the south-central and southeastern areas (Castle Garden-Wallace Creek-Burnt Wagon), the plate 3 map shows gradients of 1.0 to 1.2 °F/100 ft; whereas, the map by Pawlewicz (1993) shows gradients of 1.6 °F/100 ft and greater. We attribute the discrepancy in this portion of the basin to our exclusion of the high-temperature outliers.

The map in plate 3 also can be compared with the thermal gradient map of Hinckley and Heasler (1987), which is based on heat flow determinations from precision temperature measurements in stabilized wells and from apparently uncorrected bottom-hole temperatures in oil and gas wells. Their goal was to determine areas of possible geothermal resource, so they highlighted areas with thermal gradients greater than 1.5 °F/100 ft. In general, the plate 3 map is congruent with the map of Hinckley and Heasler (1987), except that the latter extends farther south and displays anomalously high gradients in that direction. Lacking data from the westernmost anticlines of the Wind River Basin, we incorporated the closed contours labeled 1.5 and 2.0 °F/100 ft from the map of Hinckley and Heasler (1987) into the plate 3 map. These two thermal anomalies and other high-gradient areas around the periphery of the basin were attributed, probably correctly, by Hinckley and Heasler (1987) to convective flow in folds and along faults.

In summary, the data on plate 3 show that formation temperatures, as measured from fluids recovered in drillstem tests, are highest in the deep, north-central portion of the Wind River Basin. High temperatures and high thermal gradients lie below the base of the Waltman Shale Member in the north-central area. Hot spots in folded and faulted areas around the periphery of the basin are attributed to convective flow.

Vitrinite Reflectance

Vitrinite reflectance (R_o) data were compiled from Johnson and others (1991), Pawlewicz (1993), Nuccio and others (1996), and Finn and others (2006). Plotting the logarithm of R_o versus elevation (pl. 4), two types of profiles are observed: (1) a linear increase of R_o with depth (elevation), and (2) an upper near constant R_o segment underlain by a linear increase of R_o with depth. Trendlines have been fit by least-squares regression to data from individual wells. The linear R_o-elevation profiles, best exemplified by data in the Deep Wildcats area at the top of plate 4, are located in the deep north-central portion of the basin. The two-segment profiles, exemplified by data in the West Wildcats and Burnt Wagon areas, are generally located in the shallower parts of the basin. Variations exist within this two-part characterization of R_o profiles – some linearly increasing segments display changes in slope (6-1 Shoshone Arapahoe well in Sand Mesa area) and one displays a near constant interval at depth (1-5 Bighorn well in Madden area). Slopes in the near constant segment also vary, as seen by comparing trendlines in the West Poison Spider, Fuller Reservoir, and Squaw Butte areas.

On the basis of R_o values from surface samples collected from the margins of the basin (table 1), the expected R_o value at the surface is about 0.45 percent. Extrapolation of subsurface trends (pl. 4) to the surface is consistent with a value of about 0.45 percent in most areas, but yields smaller values in a few areas.

Wells in the Pavillion area display a constant R_o value of about 0.6 percent from an elevation of +1,000 to -6,000 feet, an elevation range of 7,000 ft (pl. 4). Below -6,000 ft, R_o increases to greater than 1.2 percent at about -9,000 ft. Near constant R_o values in the 0.4 to 0.6 percent range over comparable elevation ranges also were measured in the Burnt Wagon (8,500 ft), West Poison Spider (8,500 ft), Hells Half Acre (7,000 ft), and Cooper Reservoir (6,000 ft) areas and in one of three wells in the Sand Mesa area (5,000 ft). Constant R_o-depth values are commonly attributed to sampling errors – particularly drill cuttings falling from an interval that continues to erode during drilling can contaminate the cuttings obtained from a greater depth and thereby produce a near constant R_o-depth signature. However, despite this uncertainty, the data given above are believed to be valid, because (1) the near constant R_o-depth signature occurs in many wells across the basin, and (2) data are consistent among wells from +1,000 to -6,000 ft in the Pavillion area and from +500 to -4,000 ft in the West Wildcats area. (Also, see later discussion in this section.)

The difference in R_o values with depth has produced notably different levels of thermal maturity at a given elevation. At the -5,000-ft elevation in the deep, north-central areas, R_o values are 1.0 percent or greater; whereas, in the shallower areas R_o values are less than 1.0 percent, with a few exceptions. At the -10,000-ft elevation, R_o values are 2.0 percent or greater in the deep, north-central areas, but are generally less than 2.0 percent in the shallower areas. Overall thermal maturity levels are greatest in the Madden and Deep Wildcats areas.

The depths of formation boundaries are posted with gamma-ray logs next to the plots of vitrinite reflectance (pl. 4). In some areas displaying an upper, nearly constant R_o segment — Pavillion, Hells Half Acre, Wallace Creek, and the 8-22 Tribal well in the West Wildcats area — the top of the segment displaying an increase of R_o with depth coincides with the top of the Sandy Member of the Cody Shale. However, in two other areas — Fuller Reservoir and West Poison Spider — the top of the lower segment lies either shallower or deeper than the top of the Sandy Member. In other areas, lack of data preclude a comparison.

The R_o data displayed in plate 4 are replotted as a function of depth instead of elevation and grouped by formation instead of area (figs. 3*A*-3*F*). Individual data points are identified by area rather than by well. The six formation groups are ordered from oldest (fig. 3*A*) to youngest (fig. 3*F*). A reference trendline, $\log(R_o) = -0.464 + 5.624\text{x}10^{-5}z$, where z is depth in feet, appears on each figure. The trendline is a least-squares fit to R_o data from three wells in the Deep Wildcats area.

Figures 3*A*-3*F* show that

- in all formations, the highest R_o values are in wells in the north-central areas (red symbols) – Sand Mesa, Bonneville, Madden, Deep Wildcats, and Garrison Draw – where the strata are the most deeply buried.
- R_o values from the Squaw Butte area (figs. 3*C*, 3*D*, 3*E*) lie either close to the trendline or on the low side of the

Table 1. Vitrinite reflectance (in percent) from surface samples, Wind River Basin, Wyoming, from Nuccio and others (1993).

Formation	Number of valid samples	Range of valid samples Minimum	Maximum	Average of valid samples
Fort Union Formation	7	0.29	0.43	0.38
Lance Formation	7	0.39	0.55	0.46
Meeteetse Formation	18	0.39	0.49	0.43
Mesaverde Formation	31	0.40	0.60	0.45
Cody Shale	5	0.38	0.44	0.41
Frontier	12	0.43	0.61	0.48

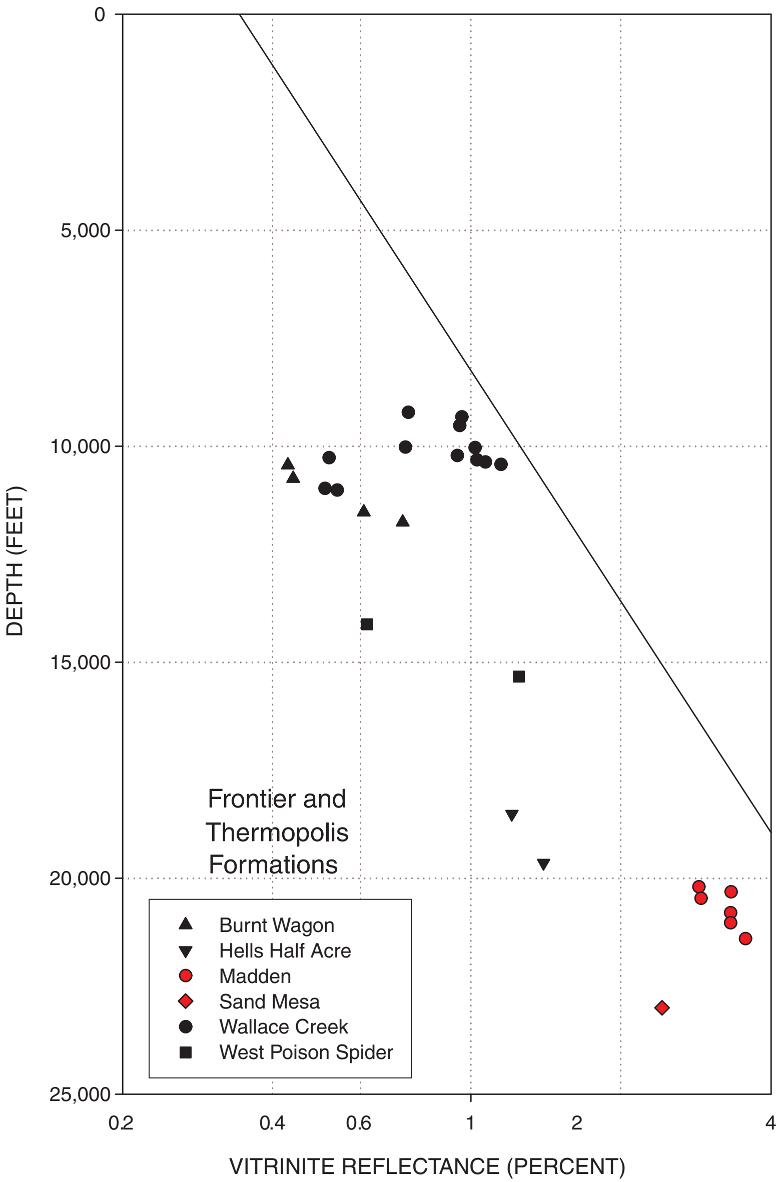


Figure 3*A*. Vitrinite reflectance as a function of depth for Frontier Formation and Thermopolis Shale. Wells in the deep north-central areas of the Wind River Basin are denoted by red symbols and wells in shallower areas by black symbols. The trendline is a least-squares fit to R_0 data from three wells in the Deep Wildcats area.

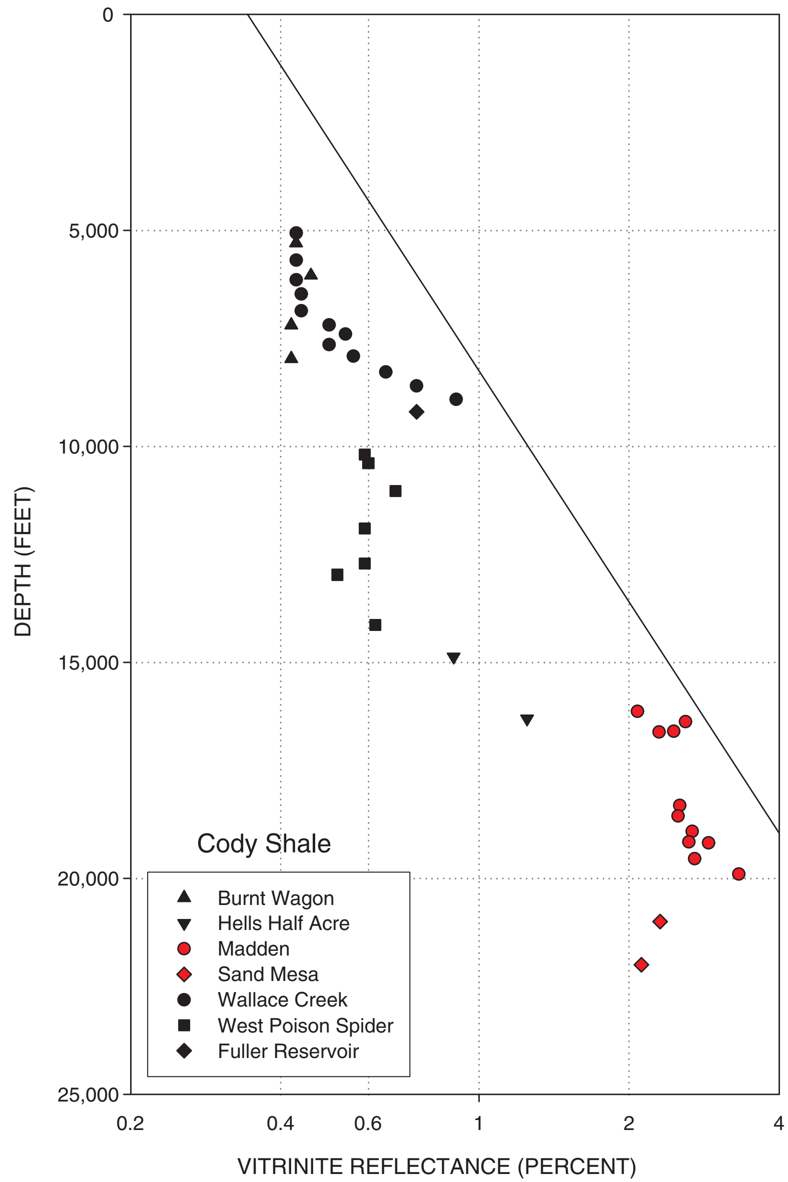


Figure 3*B*. Vitrinite reflectance as a function of depth for Cody Shale. Wells in the deep north-central areas of the Wind River Basin are denoted by red symbols and wells in shallower areas by black symbols. The trendline is a least-squares fit to R_0 data from three wells in the Deep Wildcats area.

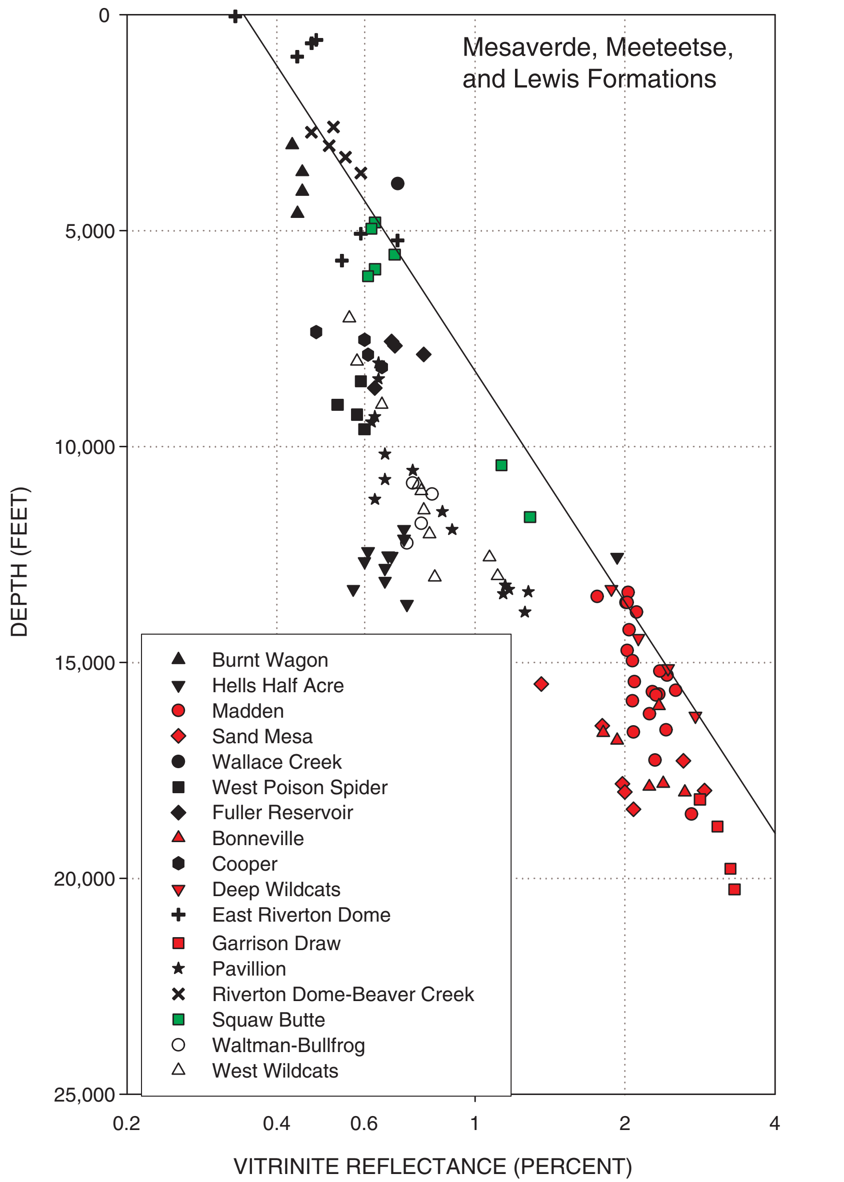


Figure 3*C*. Vitrinite reflectance as a function of depth for Mesaverde Formation, Meeteetse Formation, Lewis Shale, and equivalent formations. Wells in the deep north-central areas of the Wind River Basin are denoted by red symbols, wells in shallower areas by black symbols, and wells in the Squaw Butte area by green symbols. The trendline is a least-squares fit to R_0 data from three wells in the Deep Wildcats area.

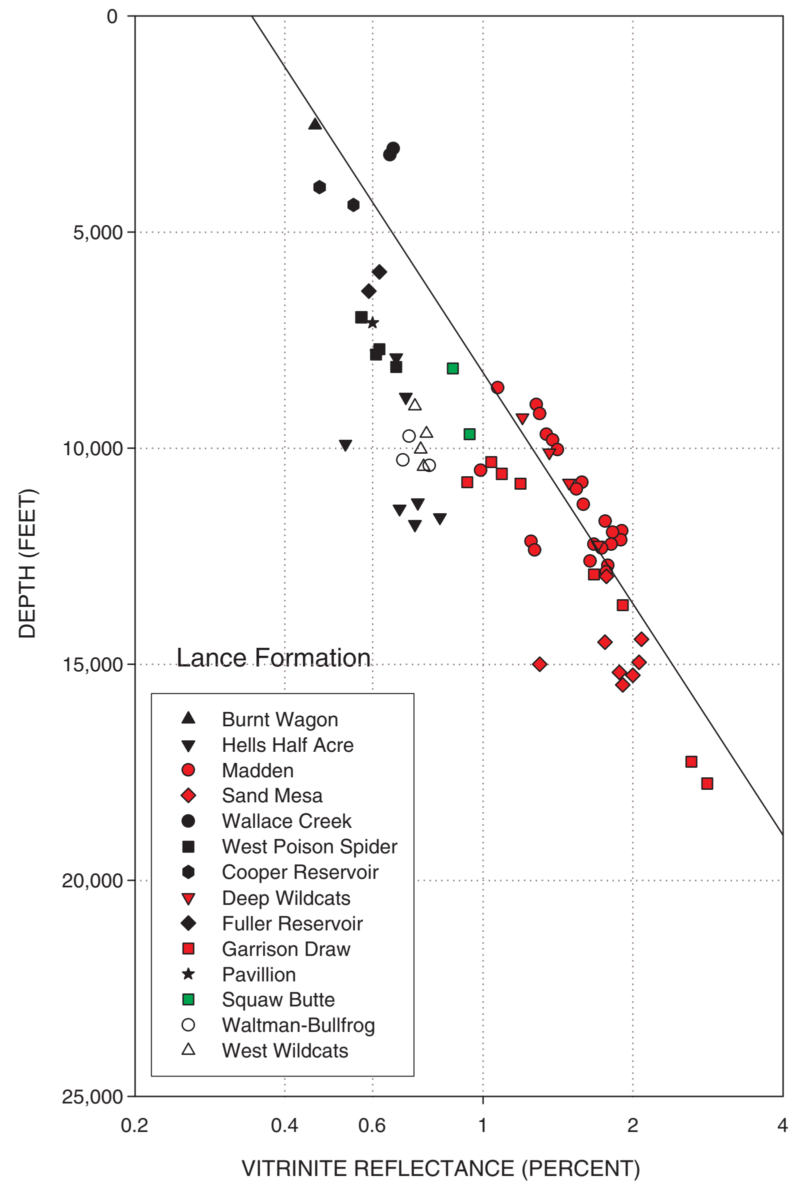


Figure 3*D*. Vitrinite reflectance as a function of depth, for Lance Formation. Wells in the deep north-central areas of the Wind River Basin are denoted by red symbols, wells in shallower areas by black symbols, and wells in the Squaw Butte area by green symbols. The trendline is a least-squares fit to R_0 data from three wells in the Deep Wildcats area

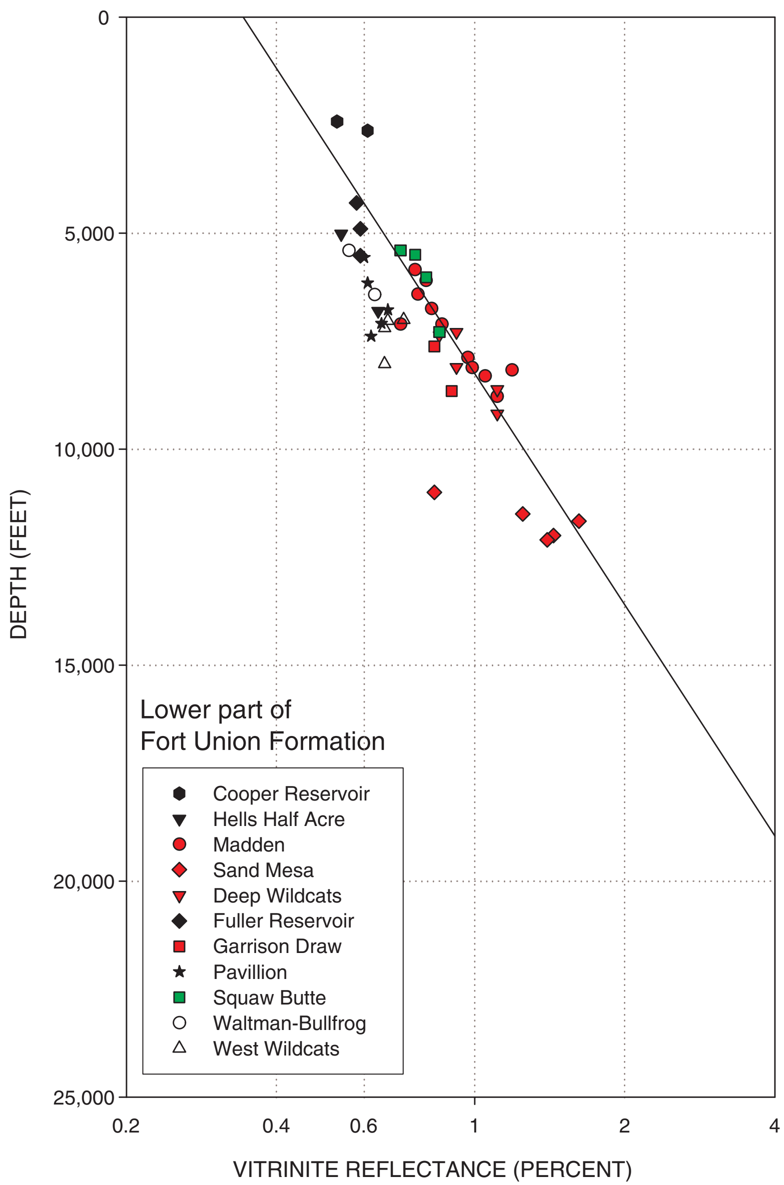


Figure 3*E*. Vitrinite reflectance as a function of depth for lower part of the Fort Union Formation. Wells in the deep north-central areas of the Wind River Basin are denoted by red symbols, wells in shallower areas by black symbols, and wells in the Squaw Butte area by green symbols. The trendline is a least-squares fit to R_0 data from three wells in the Deep Wildcats area.

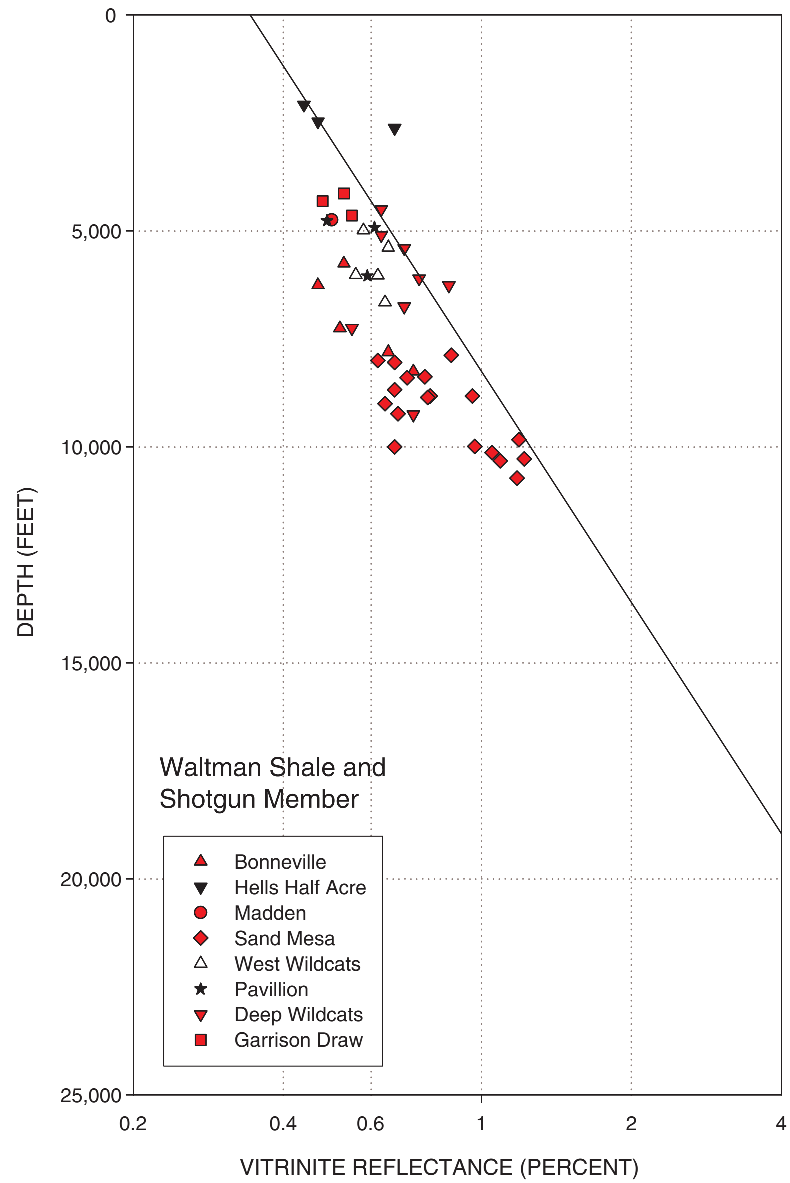


Figure 3*F*. Vitrinite reflectance as a function of depth for Waltman Shale and Shotgun Members of Fort Union Formation. Wells in the deep north-central areas of the Wind River Basin are denoted by red symbols and wells in shallower areas by black symbols. The trendline is a least-squares fit to R_0 data from three wells in the Deep Wildcats area.

trendline and are consistent with data from the north-central wells;

- values in the Lance Formation in the Madden area mostly fall to the right of the trendline (fig. 3*D*), so that on a depth-adjusted basis the Lance Formation in the Madden area is the most thermally mature in the entire basin;

- near constant R_o segments in shallower areas (black symbols) are offset from linearly increasing R_o segments in deeper areas (red symbols) in the Mesaverde, Meeteetse, and Lewis Formations (fig. 3*C*), the Lance Formation (fig. 3*D*), and the lower part of the Fort Union (fig. 3*E*). Near constant R_o segments are not present in the Waltman Shale and Shotgun Members (fig. 3*F*). All R_o values plot left of the trendline in the Cody Shale (fig. 3*B*) and Frontier and Thermopolis Formations (fig. 3*A*), indicating that thermal maturity levels are reduced in these formations on a depth-adjusted basis. Near constant R_o segments appear to be present in the Cody Shale (fig. 3*B*) but are not clearly present in Frontier and Thermopolis Formations (fig. 3*A*) because of data scatter.

A constant R_o-depth signature was described by Law and others (1989) as a segment in "kinky" vitrinite profiles. Drawing examples from the Piceance, Green River, and Alberta Basins, Law and others (1989) showed near constant R_o segments that were 2,000 to 4,000 ft in vertical extent and were bounded by both underlying and overlying segments in which R_o increased with depth. The near constant segments shown in plate 4 range from 5,000 to 8,500 vertical feet with an overlying segment that is either thin and near the surface, as in the Burnt Wagon area, or is undefined due either to having been partly eroded, or else to a lack of data.

A near constant R_o segment requires that formation temperatures remained constant for a long period of geologic time. Law and others (1989) determined that a constant R_o segment cannot be quantitatively explained without assuming thermal conductivities to be unrealistically high or that heat is transported convectively. They hypothesized that the constant R_o segments developed within overpressured intervals containing both gas and water. However, in the Wind River Basin, deep overpressured intervals occur in the north-central areas where R_o gradients are not segmented, and constant R_o segments occur in the shallower parts of the basin. It appears that, in this basin, the isothermal conditions prevailing when R_o was "set" were caused by convection, but not necessarily within an overpressured cell.

Extent of Waltman Shale Member

Because of its thickness and lateral extent, the Waltman Shale Member of the Fort Union Formation played an important role in the distribution of fluids and pressure during basin evolution. (See Roberts and others (Chapter 5, this CD-ROM) for a discussion of the stratigraphic distribution and geologic setting of the Waltman Shale Member.) The presence of the Waltman Shale Member is revealed by high gamma-ray, low resistivity, and high sonic travel time (pl. 5); shading of the resistivity and sonic logs highlights the shalier units below, within, and above the Waltman Shale Member. In the seven wells in the northwestern part of the basin where the Waltman is absent, no shading is shown on the logs. In most wells, the resistivity log reverts to a high resistivity below the base of the Waltman Shale Member, and is as diagnostic as the sonic log. However, in four wells (Bonneville Unit 2, Long Butte Unit 5, Vail 1-32, and MDU Freedom 1-29), the resistivity is low and hence shaded below the base of the Waltman. A single swabbed water sample from the Fort Union Formation in the Bonneville Unit 2 well had total dissolved solids of 127,111 parts per million (ppm), a high salinity compared with other values (see Water Salinity section), which could readily explain the low resistivity. Water analyses are not available for the other three low-resistivity wells, but it is likely that high water salinity is the cause of the low resistivity.

In the deeper part of the basin, the Waltman Shale Member is thousands of feet thick. Keefer (1997) cites 3,850 ft for the member in the Monsanto MDU Freedom 1-29 well, which is shown in plate 5 with a thickness of 3,200 feet, because of a difference in defining the top of the member in this particular well. Although it thins in all directions from this location, the Waltman Shale Member is thick and continuous over a large part of the basin interior, and could form a seal throughout most of its total area (pl. 5; map is from Roberts and others, Chapter 5, this CD-ROM). The area in which the thickness exceeds 500 ft includes the Madden anticline, which is overpressured below the Waltman. The extent of the Waltman must have affected the distribution of hydrocarbons in the basin because a large fraction of the gas generated in the Lance and Fort Union Formations has been generated since its deposition (Roberts and others, Chapter 6, this CD-ROM). Where present, the Waltman Shale Member also has prevented the downward flow of meteoric water to depths deeper than the top of the shale, although lateral migration of meteoric water within units deeper than the Waltman Shale Member is possible.

Note that even where the Waltman Shale Member is present, it may not form a continuous barrier to fluid flow. For example, in the Fuller Reservoir II 22-25 well, the Waltman Shale Member is 575 feet thick and the thickest continuous shale is 160 feet thick. In the Love Ranch 1 well, the logs reveal only two conductive shales with thicknesses of 42 and 28 feet. Where the Fort Union Formation crops out at the surface toward the south boundary of the Wind River Basin Province, only thin shales of the Waltman have been observed (Johnson, Chapter 10, this CD-ROM). Thin shales also are present in the Love Ranch 1 well, so it should be emphasized that the seal could be incomplete in this area. Although several hundred feet of the Waltman Shale Member is exposed along the Casper arch to the east, these exposures are in the overriding block of the Casper arch thrust, which could form an effective seal.

Water Salinity

Data on the salinity of waters produced from the lower part of the Fort Union Formation and the Lance Formation in the Wind River Basin are from a USGS database (Breit, 2002). Data for each well were edited and averaged to provide a value for mapping. The number of samples ranged from 1 to 15 per well. After a few wells were eliminated due to disparities in salinity values or questionable locations, 92 wells were retained for mapping (fig. 4).

Total dissolved solids (TDS) are represented by symbols in logarithmically spaced intervals (fig. 4). By way of reference, 32,000 ppm is a nominal value for sea water, 5,000 ppm is the upper limit for surface disposal of produced waters in Wyoming, and 500 ppm is a secondary standard for drinking water. Most of the samples range from 2,500 to 5,000 ppm or 5,000 to 10,000 ppm, therefore are considerably fresher than sea water, as is generally the case for formation waters in Rocky Mountain basins.

TDS values are generally less than 5,000 ppm in the southern part of the basin where the top of the Mesaverde Formation lies at elevations shallower than -5,000 ft, or approximately 10,000 ft depth (fig. 4). Values in the deeper part of the basin are in the 5,000 to 10,000 ppm range; clusters of values in this range exist in the Madden and Frenchie Draw areas. The highest salinites, ranging from 10,000 to 20,000 ppm and 20,000 to 120,000 ppm, lie between the two aforementioned areas, as well as south of the Frenchie Draw area, in the Waltman-Bullfrog area, and in the Bonneville area. Therefore, the increase of salinity from south to north is interrupted by wells with salinities in excess of 10,000 ppm.

Sonic Logs as Indicators of Overpressure

In many sedimentary basins the compaction-driven increase in sonic velocity with depth is interrupted by a decrease in velocity associated with high pore pressures that exist at present (overpressure) or existed at sometime in the past (paleo-overpressure). The depth where the first velocity decrease occurs is interpreted as the top of an overpressure

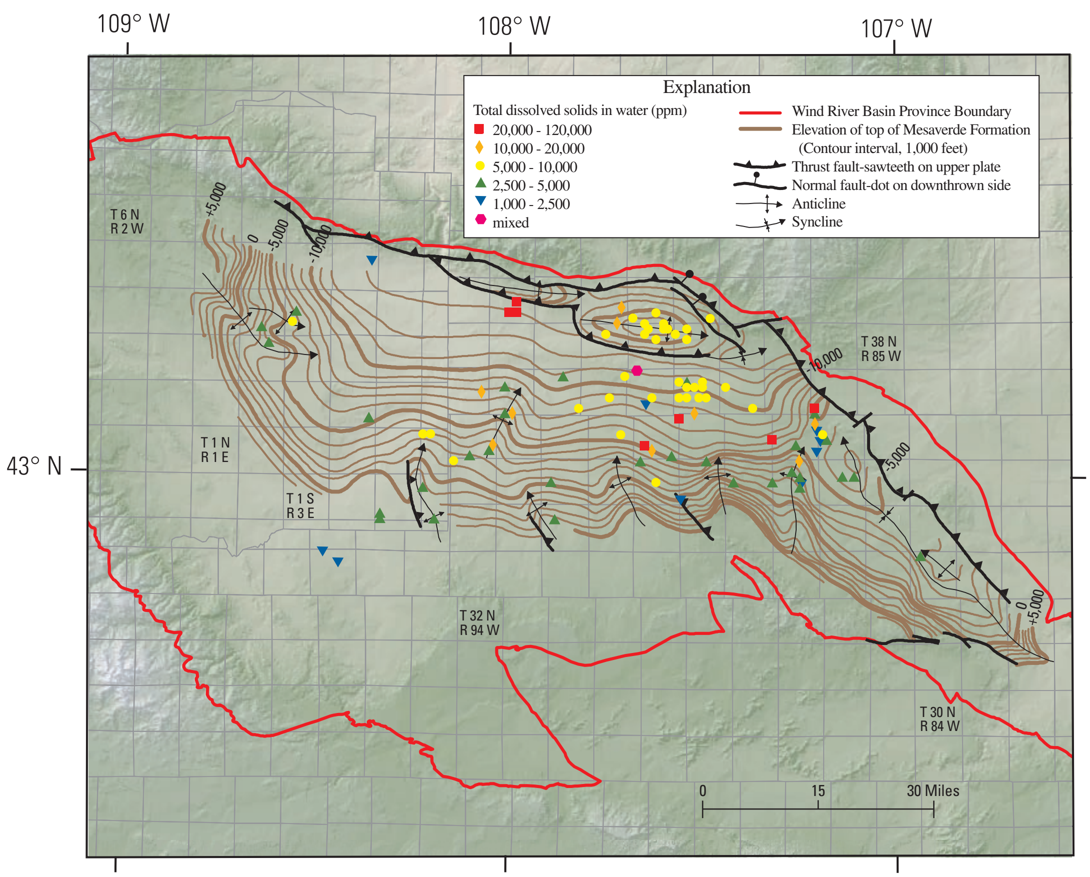


Figure 4. Map of Wind River Basin showing distribution of total dissolved solids in waters produced from the Fort Union and Lance Formations. Structure contours on top of Mesaverde Formation from Johnson and others (1996). Abbreviation: ppm, parts per million.

or paleo-overpressure zone. Such systematic decreases in sonic velocity were documented by Surdam and others (1997) in several Rocky Mountain basins, including the Wind River Basin. Subsequently, Surdam and others (2003) combined seismic velocity analysis with well log data to map a velocity inversion surface throughout the Wind River Basin. The velocity-inversion surface separates a normally pressured, water-dominated compartment from an underlying, anomalously pressured gas-charged compartment, as illustrated by Surdam and others (2003) with two- and three-dimensional views of the basin. This section discusses the characteristics of sonic and resistivity logs in the Cody Shale and underlying formations and compare these characteristics with mud weight and with pressures from drillstem tests.

Gamma-ray, resistivity, and sonic logs from 28 wells penetrating most or all of the Cody Shale and underlying Cretaceous formations are displayed in plate 6 (sheets 1 and 2; locations shown in inset). Where available, mud weights and pressures from drillstem tests also are plotted. The sonic logs were acquired between 1963 and 1990. Most were acquired with borehole-compensated sonic logging tools; some were acquired with long-spaced sonic tools. Sonic logs are displayed as slowness or inverse velocity in microseconds per foot (µs/ft); a leftward increase in slowness corresponds to a decrease in sonic velocity.

Where available for some wells, mud weights are plotted in the lefthand column with the gamma-ray log (pl. 6). Grid lines dividing the scale of 8 to 18 pounds per gallon (lb/gal) provide reference lines of 10.5, 13.0 and 15.5 lb/gal. Mud weights are plotted with a constant value downward from the depth where first reported, so that a rightward shift represents the first increase in mud weight reported on the mud log. Pressures from drillstem tests are divided by the measurement depth and plotted as pressure-depth ratios (psi/ft). The hydrostatic pressure gradient of 0.433 psi/ft serves as a reference — pressure-depth ratios greater than 0.433 psi/ft represent overpressured conditions; whereas, ratios less than 0.433 psi/ft nominally indicate underpressure but in most cases probably result from a failure to sample true pore pressure in low-permeability rocks.

To view the overpressured interval in the context of an entire well, most of the available sonic log is displayed for each well. The gradual increase in velocity with depth from near the surface to a depth of approximately 8,000 ft is due to compaction. Compaction trends are present on all the sonic logs and are most readily observed in wells in the southern and southeastern parts of the basin.

Above the top of the Cody Shale, abnormally low sonic velocity (leftward, spiky excursions on the logs) can be attributed to: (1) noise — rough borehole walls can generate noise on the sonic wavetrain, causing erroneous velocity picks; (2) borehole washouts — extreme enlargements in the wellbore can cause an apparent velocity decrease; and (3) coal beds — many of the thin leftward spikes on the upper part of the logs are caused by coal beds. Because none of these three features are of interest here, the leftward excursions of the sonic logs were trimmed in the upper parts of some of the wells in order to make the resistivity logs visible.

A "shale trendline" was interpolated between the lowermost Mesaverde Formation and the Morrison Formation. The upper end of the shale trendline is tied to the sonic traveltime in shaly sections in the lower Mesaverde Formation or upper part of the Cody Shale; the lower end is tied to shaly sections in the Morrison Formation (fig. 5; plate 6, sheets 1 and 2). In wells where the Morrison Formation was not penetrated, a representative slope was used to extrapolate the shale trendline. Because the rate of compaction decreases with depth, the slopes of the shale trendlines steepen in wells where Cody Shale penetrations are deepest, as can be seen by comparing shale trendlines from the Bighorn 1-5 well in the Madden area with the State N-14-12 well in the extreme southeastern corner of the basin. Shading between the shale trendline and the sonic log highlights the zones of anomalously low velocity.

The decrease in sonic velocity was quantified in four shaly intervals that are present across the basin, as indicated by the four lines and square symbols for the Hells Half Acre Unit 2 well (fig. 5): (1) an upper shaly interval in the Cody Shale, (2) a lower shaly interval in the Cody Shale, (3) a shaly interval in the Mowry Shale, and (4) a shaly interval in the Thermopolis Shale. For example, at 16,650 ft — the depth of the sonic velocity minimum in the upper shaly interval in the Cody Shale in the Hells Half Acre Unit 2 well (fig. 5) — the sonic slowness is 78.0 µs/ft, corresponding to a velocity of 12,820 ft/s. At the same depth, the interpolated value of sonic slowness is 62.5 µs/ft, corresponding to a velocity of 15,992 feet per second (ft/s) (fig. 5). The anomalous velocity decrease, which is the difference between the interpolated and actual velocities, is 3,172 ft/s. The velocity decreases determined in this manner for the four shaly intervals in 45 wells are plotted with depth in figure 6.

Discussion of Sonic Logs

Shading between sonic velocity and the shale trendline is visible in every well, showing that there is some reduction of sonic velocity in the Cody Shale throughout the entire basin. The sonic log deflection is greatest in the Government Tribal 33X-10 well in the Pavillion area (pl. 6, sheet 1), extending vertically for 5,000 ft and producing velocity reductions as large as 6,000 ft/s in shaly intervals. The deflection is small in wells such as the Roundup Federal 1-18 in the Burnt Wagon area (pl. 6, sheet 2), where the overall depth interval is about 2,500 ft and the largest velocity decrease is less than 2,000 ft/s.

In some wells, mud weight was kept low where the sonic log indicates overpressuring in the upper part of the Cody Shale and was increased sharply in the lowermost part of the shaly member of the Cody Shale, just above the top of the Frontier Formation (for example, the Broad Mesa 36-1, Owl Creek Tribal 1, and Fuller Reservoir II 22-25 wells). This

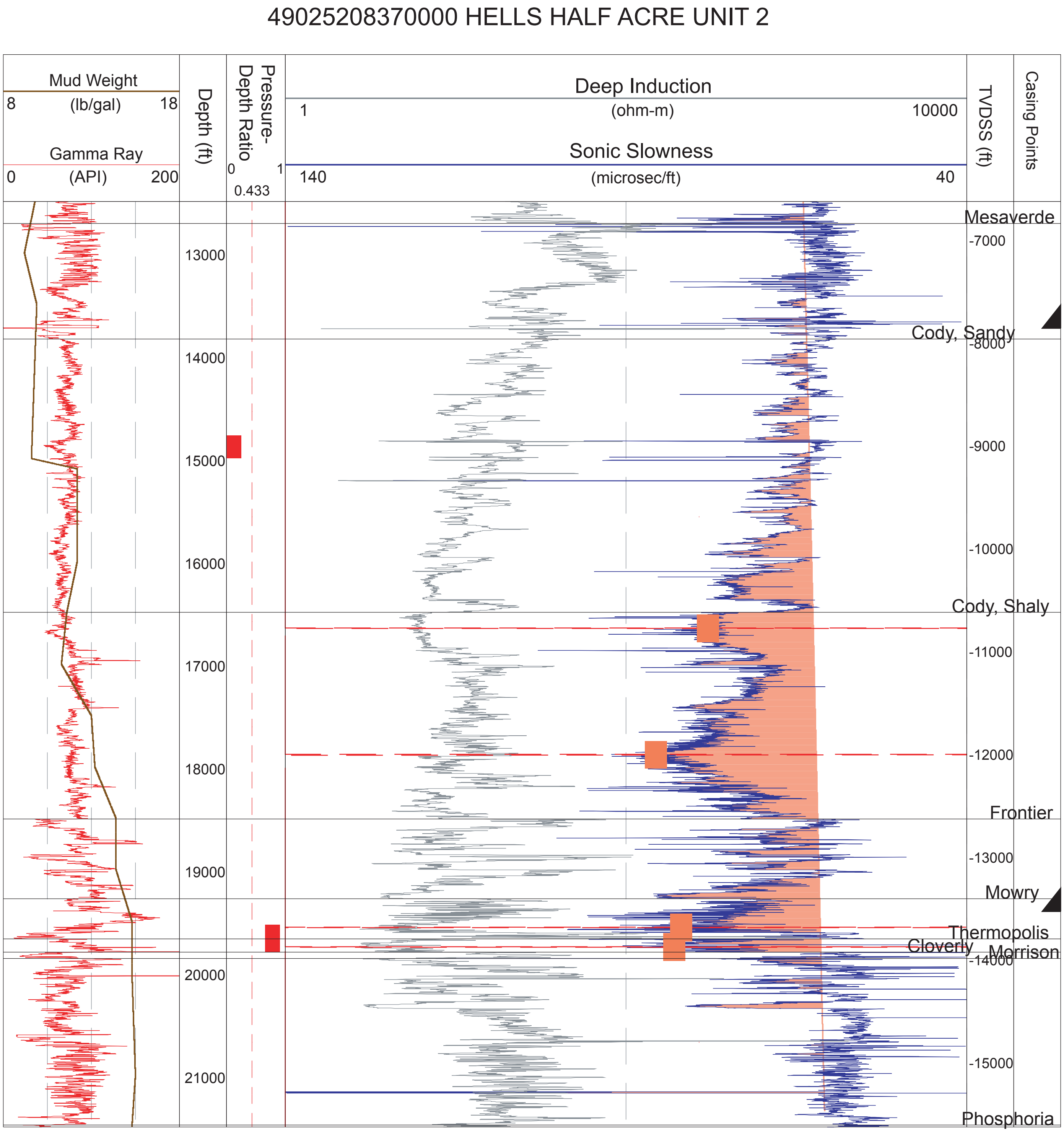
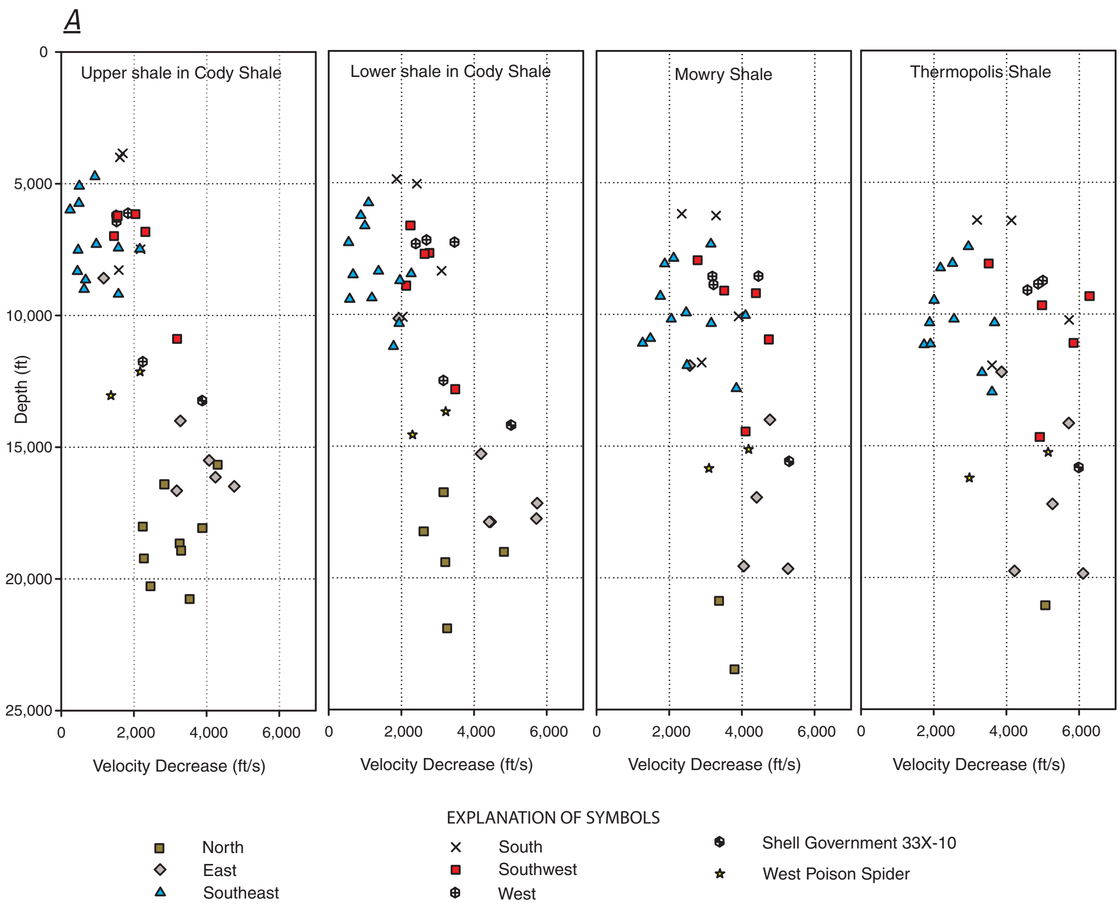


Figure 5. Well logs, mud weight, and pressure-depth ratios from drillstem tests in the Hells Half Acre Unit 2 well. Four horizontal dashed lines intersect sonic velocity minima (sonic slowness maxima) within shaly intervals (orange squares). Shading highlights zones of anomalously low velocity between the sonic slowness log and a trendline indicating the unperturbed sonic response in shale. Abbreviations: lb/gal, pounds per gallon; ohm-m, ohm-meters; TVDSS, true vertical depth subsea.



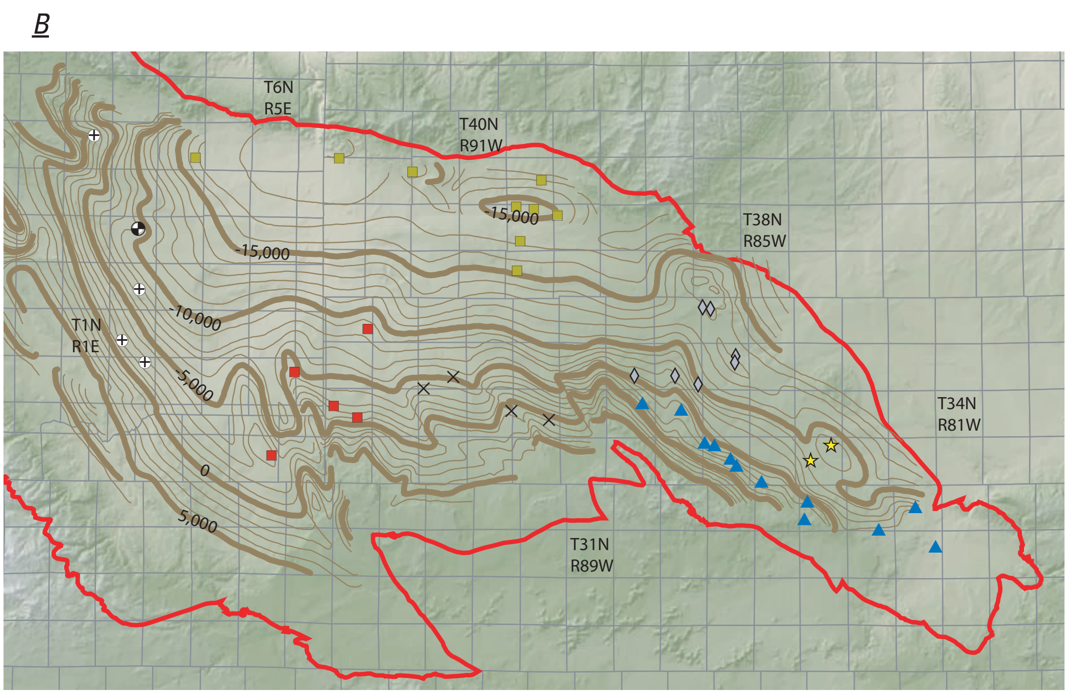


Figure 6. *A.* Decrease in sonic velocity in four shaly units in 45 wells. Due to limited depth of penetration or incomplete logging intervals in some wells, a velocity decrease could not be determined for every shaly unit; consequently, the number of points varies from panel to panel. ft/s, feet per second. *B.* Map of well locations for sonic velocity decreases plotted in *A*. Contours show elevation of Frontier Formation, in feet.

apparent disparity between mud weight and sonic velocity is attributed to the low permeability of most of the Cody Shale, preventing pressure communication between the formation and the wellbore. The drilling history of the Government Tribal 33X-10 well provides evidence for a lack of communication: (1) mud weights of 9.4 to 9.8 lb/gal were used to drill the Cody Shale and were increased in the Frontier, (2) at 15,016 ft in the Frontier Formation, the well blew out with 14.6 lb/gal mud in the well; the resulting fire burned down the derrick (Bilyeu, 1978), and (3) after gaining control of the well, 15 lb/gal mud was used to drill deeper. The 60 percent increase in mud weight (9.4 to 15 lb/gal) at the top of the Frontier does not represent a 60 percent increase in pore pressure between the Cody Shale and the Frontier Formation because the true pore pressure in the Cody Shale was not detected because of lack of pressure communication between the formation and wellbore. In contrast, good permeability in the Frontier Formation allows pressure communication between formation and wellbore and consequently mud weight reflects the pore pressure in the formation.

In some wells, mud weight was increased near the top of the Frontier Formation and then kept high in deeper intervals where the sonic log indicates normal formation pressure. In the Government Tribal 33X-10 (pl. 6, sheet 1) and the Fuller Reservoir II 22-25 (pl. 6, sheet 2) wells, mud weight was kept high to control the pore pressure in the Frontier Formation while continuing to drill ahead in the Morrison Formation. After the well was cased, a lower mud weight was used to drill deeper. Thus the apparent disparity between normal sonic velocity and high mud weight in the Morrison Formation results from the need to control the highest pore pressure in an uncased section of the well.

Corroborative pressure data from drillstem tests are disappointingly sparse. Many tests recorded low pressures, presumably due to poor communication between wellbore and formation, resulting in the near zero pressure gradients posted in plate 6, sheets 1 and 2. In three noteworthy exceptions, however, excellent correspondence exists among high pore-pressure gradients from drillstem tests, high mud weight, and low sonic velocity: at 19,600 ft in the Hells Half Acre Unit 2 well (fig. 5, pl. 6, sheet 2), at 14,800 ft in the Shell Government 33X-10 well (pl. 6, sheet 1), and at 13,300 ft in the Fuller Reservoir II 22-25 well (pl. 6, sheet 1). In two other cases, good correspondence exists between high pore-pressure gradient and low sonic velocity: at 15,600 ft in the Birdseye Creek 4 34 94 well (pl. 6, sheet 1), and at 16,700 and 17,300 ft in the Lysite 7-1 well (pl. 6, sheet 1). These small numbers of pressure gradient measurements exceeding 0.433 psi/ft indicates the difficulty of obtaining successful drillstem tests in low permeability rock.

As previously mentioned, each well in the basin displays some decrease in sonic velocity, as shown by the shading between the sonic log velocity and interpolated velocity in plate 6. The velocity decreases are least in the southeastern wells, as shown by the narrow width of shading in the line of seven wells extending from Conoco Coal Banks 1-27 to State N-14-12 (pl. 6, sheet 2) and by the four plots in figure 6. The average velocity decreases for the twelve southeastern wells are 888 ft/s in the upper shale in the Cody Shale, 1,273 ft/s in the lower shale in the Cody Shale, 2,480 ft/s in the Mowry Shale, and 2,574 ft/s in the Thermopolis Shale. As there is no evidence of present-day overpressuring in the southeastern wells, we ascribe the velocity decreases in these wells to the remnant signature of paleo-overpressure. The additional velocity decreases in areas other than the southeastern area are then likely to be due to present-day overpressure. In other words, not all of the velocity decrease in any one well is necessarily due to present-day overpressure.

For each of the four shaly intervals in figure 6, the velocity decrease is greatest at deeper depths; however, there are some noteworthy features of the velocity decreases when considered by area. The velocity decrease in the west and southwest wells is greater than in the southeast wells, and the separation between the west/southwest and the southeast wells is much greater in the Thermopolis Shale than in the upper shale in the Cody Shale — that is, the vertical gradient of velocity decrease is greater in the west/southwest than in the southeast. This effect also can be seen in the well logs. For example, compare the shading in a high-gradient well in the west, Conoco Tribal 10-1 (pl. 6, sheet 1), which increases markedly in width from top to base, with the shading in a well in the southeast, Twidale 1 (pl. 6, sheet 2), which does not increase as much from top to base. Although evidence in addition to the velocity gradients would be desirable, the relative potential for gas accumulation in the western and southwestern wells is expected to be greater in the Mowry and Thermopolis Shales than in the Cody Shale.

From evidence presented in other sections of this report, velocity decreases in the Madden area would be expected to be the greatest in the basin, but, in fact, the velocity decreases in the eastern wells, which span the Waltman-Bullfrog and Cooper areas, are the greatest (fig. 6). The velocity decrease in the Government Tribal 33X-10 well (Pavillion area) also is one of the largest in the basin. As a matter of interest, both the Pavillion area and the Waltman-Bullfrog area, although smaller than Madden, are among the largest producers of gas in the Wind River Basin (table 2).

Cumulative Fluid Production in Nine Areas

Using the field and formation assignments in a production database (IHS Energy Group, 2005), the cumulative production of fluids through 2005 was totaled for all wells in nine selected areas in the Wind River Basin. Table 2 is ordered in decreasing amounts of produced gas for these areas: Madden (1,176 billion cubic feet (BCF)), Beaver Creek and Riverton Dome (991 BCF), Waltman and Bullfrog (426 BCF), Pavillion (245 BCF), Muddy Ridge (113 BCF), Frenchie Draw

(102 BCF), Fuller Reservoir (22 BCF), Sand Mesa (4 BCF), and Deep Wildcats (3 BCF). The latter two areas are large and underexplored relative to the other seven. The number of wells contributing to production from any one of the 14 producing units ranges from none to 163 (table 2). Totals and ratios of totals are given in the bottom row of each table. Although table 2 is not a complete summary of production from the entire basin, it does permit comparison of fluid production and ratios from several different areas.

In the nine areas summarized in table 2, oil production is of minor importance compared to gas production, with the exception of the Beaver Creek-Riverton Dome area where cumulative oil production is 62 million barrels. Gas-oil ratios are generally quite high and fluctuate greatly from area to area and formation to formation; reservoirs with ratios greater than 20,000 cubic feet per barrel are considered gas accumulations. In those cases where small numbers of wells have produced miniscule volumes of oil, high gas-oil ratios are probably not meaningful.

Water production data are generally considered less reliable than oil and gas production data, because the incentives for accurate reporting are not as great. The data are presented here despite this qualification, assuming that the effect of poor reliability is somewhat lessened by aggregating wells in areas. Moreover, loss of accuracy is less a factor with data that vary greatly; for example, water production from the Fort Union Formation ranges from 34 to 37,500 barrels among the nine areas (table 2). Values ranging over three orders of magnitude can be compared even if reporting errors are as large as a factor of 2 (100 percent). The effect of large aggregate reporting errors is illustrated on a plot with logarithmic scales of water, gas, and water-gas ratio (fig. 7). Errors in the reported cumulative water and gas are assumed to be within factors of 2 and 1.2, respectively, with the resulting effect on the water-gas ratio illustrated graphically.

Confining attention to significant gas accumulations, we considered the water production and water-gas ratios for 22 cases in which cumulative gas production is greater than 9 BCF and gas-oil ratios are greater than 20,000. For these cases, the water-gas ratio ranges from 0.9 to 422 barrels of water per million cubic feet of gas (bbl/MMCF) with a median value of 11.6 bbl/MMCF and a geometric mean of 12.8 bbl/MMCF. These data are plotted in figure 8, which shows that there is no correlation between water-gas ratio and either cumulative water or gas production, nor is there any correspondence between water-gas ratio and formation, as can be seen by inspecting the spread of data for individual formations. For example, the water-gas ratio from the Fort Union Formation ranges from a low of 2.4 bbl/MMCF in Pavillion to a high of 422 barrels/MMCF in Frenchie Draw, and the water-gas ratio from the Lance Formation ranges from a low of 7.8 bbl/MMCF in Muddy Ridge to a high of 376

Table 2. Cumulative oil, gas, and water in nine areas in the Wind River Basin, Wyoming. Cumulative production figures for individual wells were aggregated for each formation and area from a production database (IHS Energy Group, 2005).

[Cumulative production is given in thousands of barrels of oil, billion cubic feet (BCF) of gas, and thousands of barrels of water. Ratios are computed in cubic feet of gas per barrel of oil (CF/barrel) and barrels of water per million cubic feet of gas (barrels/MMCF). Co-mingled production has been allocated to individual formations on a fractional basis. For example, production of 1.0 BCF designated "Fort Union/Wind River" was allocated as 0.5 BCF to Fort Union and 0.5 BCF to Wind River Formations. --, no data.]

Madden area

Formation	Number of wells	Cumulative oil (thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (thousands of barrels)	Water-gas ratio (barrels/MMCF)
Wind River	--	--	--	--	--	--
Waltman	--	--	--	--	--	--
Fort Union	163	1,239.2	421.9	340,500	10,297.3	24.4
Lance	22	15.5	49.4	3,187,738	5,017.2	101.6
Meeteetse	--	--	--	--	--	--
Mesaverde	9	2.3	34.7	15,401,696	6,442.9	185.9
Cody	22	0.4	248.4	583,171,103	6,243.2	25.1
Frontier	1	--	0.7	--	14.2	21.7
Muddy	--	--	--	--	--	--
Cloverly	--	--	--	--	--	--
Morrison	--	--	--	--	--	--
Phosphoria	--	--	--	--	--	--
Tensleep	1	--	0.1	--	13.6	195.4
Madison	8	--	420.9	--	5,326.3	12.7
TOTAL	226	1,257.3	1,176.0		33,354.8	

Table 2. Cumulative oil, gas, and water in nine areas in the Wind River Basin, Wyoming. Cumulative production figures for individual wells were aggregated for each formation and area from a production database (IHS Energy Group, 2005).— Continued

[Cumulative production is given in thousands of barrels of oil, billion cubic feet (BCF) of gas, and thousands of barrels of water. Ratios are computed in cubic feet of gas per barrel of oil (CF/barrel) and barrels of water per million cubic feet of gas (barrels/MMCF). Co-mingled production has been allocated to individual formations on a fractional basis. For example, production of 1.0 BCF designated "Fort Union/Wind River" was allocated as 0.5 BCF to Fort Union and 0.5 BCF to Wind River Formations. --, no data.]

Beaver Creek and Riverton Dome area

Formation	Number of wells	Cumulative oil (Thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (Thousands of barrels)	Water-gas ratio (Barrels/MMCF)
Wind River	--	--	--	--	--	--
Waltman	--	--	--	--	--	--
Fort Union	15	397.2	2.5	6,256	4,705.9	1,894.0
Lance	--	--	--	--	--	--
Meeteetse	--	--	--	--	--	--
Mesaverde	8	0.9	2.3	2,475,301	4,702.2	2,058.1
Cody	44	3,722.2	19.2	5,158	7,965.9	414.9
Frontier	96	1,917.4	445.2	232,205	939.7	2.1
Muddy	29	35.4	12.6	354,845	21.5	1.7
Cloverly	66	1,612.5	359.3	222,850	715.0	2.0
Morrison	21	8.9	6.7	748,044	11.4	1.7
Phosphoria	32	1,055.2	118.8	112,583	264.7	2.2
Tensleep	31	8,584.3	11.2	1,303	7,977.7	713.0
Madison	35	45,136.4	12.7	282	232,071.0	18,253.7
TOTAL	377	62,470.5	990.5		259,374.9	

Waltman and Bullfrog area

Formation	Number of wells	Cumulative oil (Thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (Thousands of barrels)	Water-gas ratio (Barrels/MMCF)
Wind River	1	0.0	0.1	2,082,085	--	--
Waltman	--	--	--	--	--	--
Fort Union	49	182.4	125.5	688,104	341.7	2.7
Lance	103	1,490.2	257.5	172,793	2,693.8	10.5
Meeteetse	2	0.2	0.0	198,373	31.7	--
Mesaverde	2	1.9	0.4	201,819	5.0	12.7
Cody	--	--	--	--	--	--
Frontier	7	2.8	14.7	5,272,269	759.2	51.6
Muddy	4	0.3	26.5	96,378,587	237.8	9.0
Cloverly	4	--	1.1	--	58.5	52.4
Morrison	--	--	--	--	--	--
Phosphoria	--	--	--	--	--	--
Tensleep	--	--	--	--	--	--
Madison	--	--	--	--	--	--
TOTAL	172	1,677.8	425.8		4,127.6	

Table 2. Cumulative oil, gas, and water in nine areas in the Wind River Basin, Wyoming. Cumulative production figures for individual wells were aggregated for each formation and area from a production database (IHS Energy Group, 2005).— Continued

[Cumulative production is given in thousands of barrels of oil, billion cubic feet (BCF) of gas, and thousands of barrels of water. Ratios are computed in cubic feet of gas per barrel of oil (CF/barrel) and barrels of water per million cubic feet of gas (barrels/MMCF). Co-mingled production has been allocated to individual formations on a fractional basis. For example, production of 1.0 BCF designated "Fort Union/Wind River" was allocated as 0.5 BCF to Fort Union and 0.5 BCF to Wind River Formations. --, no data.]

Pavillion area

Formation	Number of wells	Cumulative oil (Thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (Thousands of barrels)	Water-gas ratio (Barrels/MMCF)
Wind River	84	0.6	118.9	206,347,118	102.3	0.9
Waltman	--	--	--	--	--	--
Fort Union	66	3.8	126.0	33,339,255	305.8	2.4
Lance	1	--	0.2	--	--	--
Meeteetse	--	--	--	--	--	--
Mesaverde	--	--	--	--	--	--
Cody	1	1.1	0.1	128,318	0.0	0.1
Frontier	1	0.2	0.1	522,527	--	--
Muddy	--	--	--	--	--	--
Cloverly	--	--	--	--	--	--
Morrison	--	--	--	--	--	--
Phosphoria	--	--	--	--	--	--
Tensleep	--	--	--	--	--	--
Madison	--	--	--	--	--	--
TOTAL	153	5.6	245.3		408.1	

Muddy Ridge area

Formation	Number of wells	Cumulative oil (Thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (Thousands of barrels)	Water-gas ratio (Barrels/MMCF)
Wind River	2	--	4.1	--	0.8	0.2
Waltman	--	--	--	--	--	--
Fort Union	42	187.5	54.0	287,746	812.6	15.1
Lance	25	81.6	17.4	213,756	135.5	7.8
Meeteetse	20	42.7	9.2	216,457	117.0	12.7
Mesaverde	29	124.6	26.6	213,658	268.9	10.1
Cody	1	--	0.0	--	--	--
Frontier	--	--	--	--	--	--
Muddy	1	15.3	2.0	128,762	--	--
Cloverly	--	--	--	--	--	--
Morrison	--	--	--	--	--	--
Phosphoria	--	--	--	--	--	--
Tensleep	--	--	--	--	--	--
Madison	--	--	--	--	--	--
TOTAL	120	451.7	113.4		1,334.9	

Table 2. Cumulative oil, gas, and water in nine areas in the Wind River Basin, Wyoming. Cumulative production figures for individual wells were aggregated for each formation and area from a production database (IHS Energy Group, 2005).— Continued

[Cumulative production is given in thousands of barrels of oil, billion cubic feet (BCF) of gas, and thousands of barrels of water. Ratios are computed in cubic feet of gas per barrel of oil (CF/barrel) and barrels of water per million cubic feet of gas (barrels/MMCF). Co-mingled production has been allocated to individual formations on a fractional basis. For example, production of 1.0 BCF designated “Fort Union/Wind River” was allocated as 0.5 BCF to Fort Union and 0.5 BCF to Wind River Formations. --, no data.]

Frenchie Draw area

Formation	Number of wells	Cumulative oil (Thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (Thousands of barrels)	Water-gas ratio (Barrels/MMCF)
Wind River	--	--	--	--	--	--
Waltman	--	--	--	--	--	--
Fort Union	93	2266.9	89.0	39,249	37,528.8	421.8
Lance	21	132.5	13.3	100,338	4,997.4	375.9
Meeteetse	--	--	--	--	--	--
Mesaverde	--	--	--	--	--	--
Cody	--	--	--	--	--	--
Frontier	--	--	--	--	--	--
Muddy	--	--	--	--	--	--
Cloverly	--	--	--	--	--	--
Morrison	--	--	--	--	--	--
Phosphoria	--	--	--	--	--	--
Tensleep	--	--	--	--	--	--
Madison	--	--	--	--	--	--
TOTAL	114	2,399.4	102.3		42,526.2	

Fuller Reservoir area

Formation	Number of wells	Cumulative oil (Thousands of barrels)	Cumulative gas (BCF)	Gas-oil ratio (CF/Barrel)	Cumulative water (Thousands of barrels)	Water-gas ratio (Barrels/MMCF)
Wind River	--	--	--	--	--	--
Waltman	35	2,534.9	4.9	1,932	16,861.8	3,442.3
Fort Union	37	5.7	16.6	2,926,576	244.5	14.7
Lance	1	0.2	0.1	531,869	4.9	41.0
Meeteetse	--	--	--	--	--	--
Mesaverde	--	--	--	--	--	--
Cody	--	--	--	--	--	--
Frontier	--	--	--	--	--	--
Muddy	--	--	--	--	--	--
Cloverly	--	--	--	--	--	--
Morrison	--	--	--	--	--	--
Phosphoria	--	--	--	--	--	--
Tensleep	--	--	--	--	--	--
Madison	--	--	--	--	--	--
TOTAL	73	2,540.8	21.6		17,111.2	

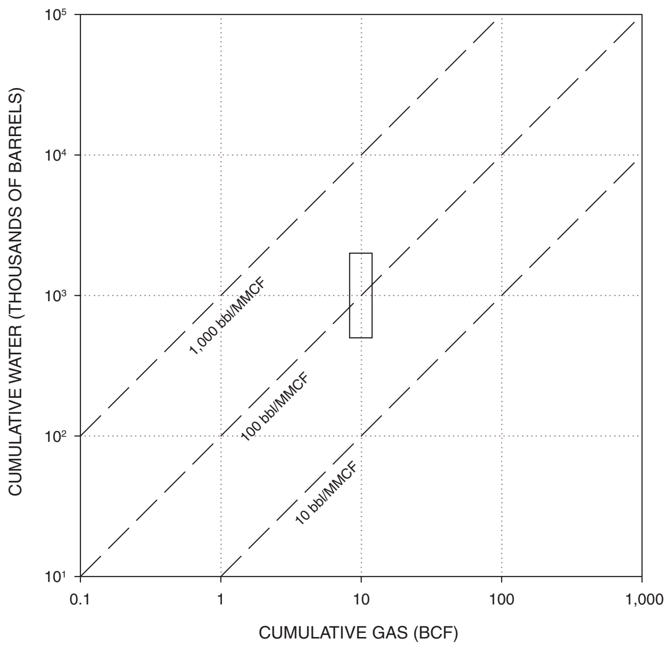


Figure 7. Plot of cumulative water production vs. gas production with water-gas ratio in barrels per million cubic feet of gas (bbl/MMCF) shown as dashed lines. The box illustrates the sensitivity of the water-gas ratio to a hypothetical case of 1,000,000 barrels of produced water and 10 billion cubic feet (BCF) of gas, with uncertainty in water ranging from 500,000 to 2,000,000 barrels and uncertainty in gas ranging from 8.3 to 12 BCF.

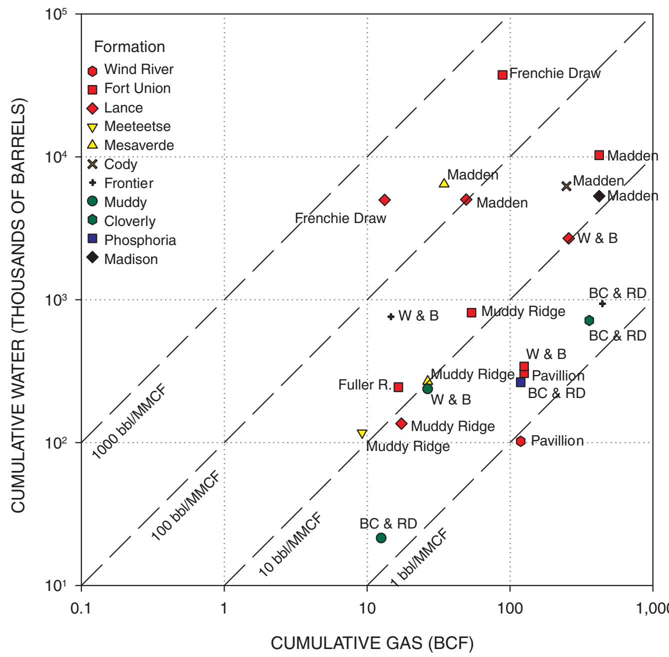


Figure 8. Plot of cumulative water production vs. gas production for 22 cases with gas production greater than 9 BCF and gas-oil ratios greater than 20,000, identified by formation and area. W&B, Waltman-Bullfrog area; BC&RD, Beaver Creek-Riverton Dome area; Fuller R., Fuller Reservoir area; BCF, billion cubic feet; bbl/MMCF, barrels per million cubic feet.

bbl/MMCF in Frenchie Draw. However, there is a dependency of water-gas ratio upon area, which is manifest when the data are identified only by area, irrespective of formation (fig. 9). The Frenchie Draw area posts the highest water-gas ratios of all areas, around 400 bbl/MMCF from both the Fort Union and Lance Formations. Several areas show water-gas ratios of less than 10 bbl/MMCF. From inspection of figure 9, the seven areas with gas production greater than 9 BCF are, in decreasing order of water-gas ratio, Frenchie Draw, Madden, Waltman and Bullfrog, Fuller Reservoir, Muddy Ridge, Beaver Creek and Riverton Dome, and Pavillion.

Estimates of Ultimate Recovery of Gas

Estimated ultimate recovery (EUR) of gas was computed for approximately 500 producing zones as a function of elevation in the Wind River Basin (pl. 7). EURs were calculated for each production record by a curve-fit to the entire production record (Cook, 2005). Production lifetime was varied by a Monte Carlo method with consequent variations in curve-fit parameters. The maximum lifetime allowed in the simulation was 60 years. Wells with steep decline curves are relatively unaffected by the statistical variation in lifetime, but long lifetimes are required to capture the EURs of highly productive wells with low decline rates.

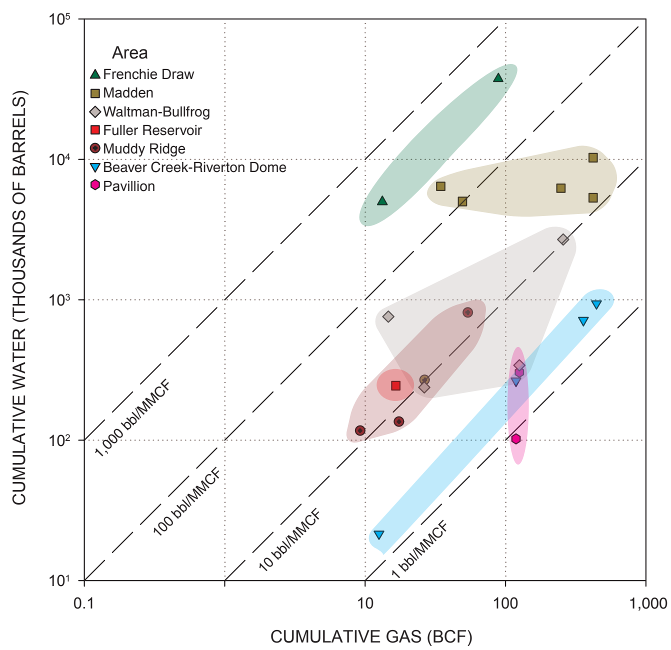


Figure 9. Plot of cumulative water production vs. gas production for the 22 cases plotted in figure 8, identified by area only. BCF, billion cubic feet; bbl/MMCF, barrels per million cubic feet.

The mean EUR values derived from the simulations are plotted for 15 different areas of the basin (pl. 7). Symbols designate the producing formation; if the producing interval incorporates two formations (for example, Frontier-Dakota), then the symbol represents the formation listed first (Frontier). Points are plotted at the elevation midpoints of the perforated intervals. Because depths of perforated intervals were not reported for most wells, the data shown in plate 7 constitute less than one-third of the gas production reported for the Wind River Basin by IHS Energy Group (2005). Points to the right of the vertical red dashed line represent ultimate gas production greater than 1 BCF. Examination of plate 7 shows that:

1. With the exception of the Madden area, most of the gas from wells in the northern part of the basin has been produced from the Fort Union and Lance Formations at elevations less than -5,000 ft. Areas with four or more wells with EURs greater than 1 BCF in the Fort Union and Lance Formations are Pavillion, Muddy Ridge, Fuller Reservoir, Madden, Frenchie Draw, and Waltman-Bullfrog.
2. Many wells in the Madden area show EURs in excess of 10 BCF. The pre-eminence of the Madden area also is shown by production intervals spanning more than 18,000 vertical feet, and including six formations. Although production from the Madison Limestone is represented by only two wells, EURs of 100 BCF indicate that Madison production constitutes a large fraction of the ultimate gas recovery from the Madden area.

Summary

The drillstem tests and other data presented in the foregoing sections define two major pressure compartments in the Madden area and an extensive gas plume in the Pavillion and Muddy Ridge areas. Details of the evidence for compartmentalization are discussed next, followed by some general observations that apply to the entire Wind River Basin.

Madden Area, Lower Pressure Compartment

The lower pressure compartment extends from somewhat below the base of the Cretaceous upward to the top of Mesaverde Formation. The top of the compartment is determined by shut-in pressures from drillstem tests that increase as much as 1,600 psi with increasing depth at -9000 ft msl (pls. 1 and 2) and by an increase to 12-lb drilling mud (fig. 10). The elevation of this pronounced increase in pressure is located close to the top of the Mesaverde Formation. Below this horizon, the pressure-depth ratio is around 0.65 psi/ft (pl. 1) and the ratio of flowing pressure to shut-in pressure is remarkably high (pl. 2). The base of this pressure cell probably lies below the base of the Cretaceous sequence, where pressure reverts to a substantially lower pressure gradient (Dunleavy and Gilbertson, 1986; also see the reduction of mud weight in the bottom of the Bighorn 1-5 well, pl. 6, sheet 1). With regard to the cause of the pressure discontinuity at the top of the Mesaverde Formation, Schelling and Wavrek (1999) state that "combined molecular-isotopic analyses of gas components indicate a vertical hydrocarbon compartmentalization across the Madden Anticline that coincides with a structural discontinuity at the Mesaverde Fm. level." The northern limit to the pressure compartment may be the Cedar Ridge normal fault system (fig. 10). The Madden thrust fault could partially confine the overpressure along the southern flank of the Madden anticline, although overpressures do persist at depth south of the thrust fault (fig. 10). Vitrinite reflectance values in this interval exceed 2.0 percent (pl. 4), sufficiently high to convert oil to gas, and gas is either the only fluid or constitutes a high proportion of the fluids recovered from most drillstem tests in this interval (pl. 1). Despite the high pressure and preponderance of gas shows, water production is not low — the water-gas ratio is 25 bbl/MMCF in the Cody Shale and 186 bbl/MMCF in the Mesaverde Formation (table 2). Sonic logs show substantial velocity decreases in the interval from within the Cody Shale downward to the base of the Cretaceous, but not in the Mesaverde Formation (pl. 6, sheet 1).

Madden Area, Upper Pressure Compartment

The upper pressure compartment extends from the top of the Mesaverde Formation upward to the base of the Waltman Shale Member. The shaly interval of the Waltman is more than 2,000 feet thick in the Madden area (pl. 5); its structural configuration is shown in plate 5. In the Madden area, the Waltman serves as a pressure seal with a downward pressure increase of about 1,200 psi across the seal (pls. 1 and 2). The pressure gradient is slightly less than hydrostatic above the Waltman; whereas, below the Waltman, an elevated pressure gradient lies parallel to hydrostatic (pl. 1) and extends downward to the top of the Mesaverde Formation (pls. 1 and 2). Lateral bounds to the pressure compartment are likely to be the Cedar Ridge normal fault on the north and possibly the Madden thrust fault on the south, although extension of the Madden thrust upward into the Fort Union is not well documented (fig. 10). The bottom seal for the pressure compartment could be a structural discontinuity cited by Schelling and Wavrek (1999). The ratios of flowing to shut-in pressures are much higher in this interval than in other areas of the basin, but not as high as below the top of the Mesaverde (pl. 2). Temperatures in the lower part of the Fort Union and the upper part of the Lance indicate a thermal gradient around 2°F/100 ft, one of the highest gradients in the entire basin. Vitrinite reflectance values also are as high or higher than elsewhere in the basin (figs. 3D and 3E). The produced water-gas ratios are 24 bbl/MMCF in the Fort Union and 102 bbl/MMCF in the Lance (table 2). Fluids recovered by drillstem tests show a range of hydrocarbon-to-water ratios; at no elevation in this pressure compartment did the drillstem tests yield only hydrocarbons (pl. 1). Gases from the Fort Union,

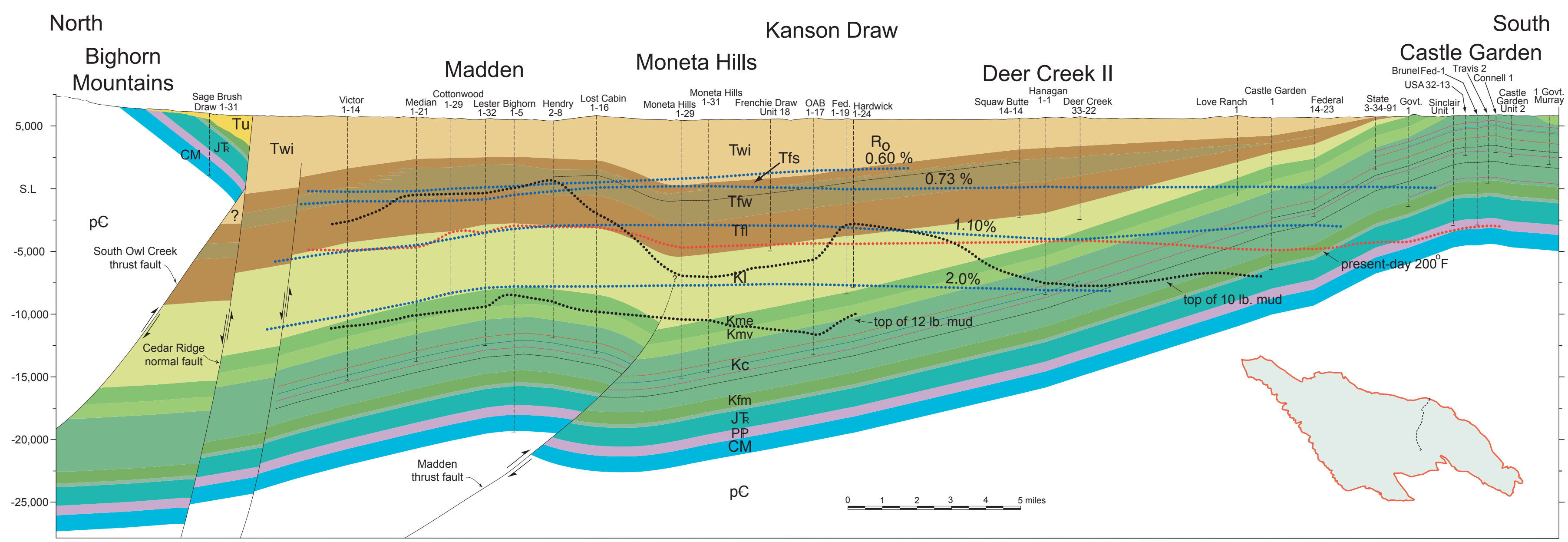


Figure 10. Simplified structure cross section from Madden field to Castle Garden area courtesy Tom Finn (see Chapter 9, this CD-ROM). Interpretation of major faults modified from Ray and Keefer (1985). (p€ , pre-Cambrian, CM, Cambrian-Mississippian; PP, Pennsylvanian-Permian; JTR, Jurassic-Triassic; Kfm, Frontier Formation and Mowry Shale; Kc, Cody Shale; Kmv, Mesaverde Formation; Kme, Meeteetse Formation; Kl, Lance Formation; Tfl, lower part of Fort Union Formation; Tfw, Waltman Shale Member of Fort Union Formation; Tfs, Shotgun Member of Fort Union Formation; Twi, Wind River Formation., Tu, undifferentiated Tertiary; R_O, vitrinite reflectance)

Lance, and Mesaverde Formations and the Cody Shale are similar and isotopically heavy, indicating that (1) considerable vertical migration occurred below the Waltman Shale Member and (2) the gas in these older strata is distinct from isotopically light gas in strata above the Waltman Shale Member (Johnson and Rice, 1993; Johnson and Keighin, 1998).

Pavillion and Muddy Ridge Areas

The Pavillion and Muddy Ridge fields are associated with local structural closures on a southeast plunging regional anticline; these fields are located approximately 10 miles southeast of outcrops of several of the producing units (Keighin and others, 1995). Pressures from drillstem tests follow a normal hydrostatic gradient of 0.433 psi/ft in Tertiary and Upper Cretaceous rocks (pls. 1 and 2). Lack of overpressure in the Tertiary and most of the Upper Cretaceous rocks is consistent with flowing pressures that are less than shut-in pressures (pl. 2). However, overpressured conditions exist in the Lower Cretaceous and lowermost Upper Cretaceous as shown by sonic logs and mud weights (see Discussion of Sonic Logs). Pressures return to normal within the Paleozoic sequence; mud weights below 16,200 feet in the Shell Tribal 33X-10 (pl. 6, Sheet 1) were apparently overbalanced (Bilyeu, 1978). Fluid temperatures from drillstem tests follow a temperature gradient of 1.2°F/100 ft in the Pavillion Field. In the Muddy Ridge Field, the 1.2°F/100 ft gradient represents a minimum, as many samples recorded higher temperatures (pl. 3). Temperature-depth ratios of 1.2°F/100 are among the lowest in the Wind River Basin and tend to be around the west and south margins of the basin (pl. 3)

Fluid recoveries from drillstem tests (pl. 1) demonstrate the presence of a gas plume extending over a vertical distance of more than 10,000 ft. The bottom of the plume lies at the base of the Lower Cretaceous, deeper than shown by drillstem test recoveries. The Waltman Shale Member is absent in this area, although an "equivalent" Waltman marks the elevation of deltaic sequences that are the temporal equivalent of the lacustrine shales (Johnson, Chapter 10, this CD-ROM). Lacking a barrier to vertical migration, the gas plume extends above the elevation of the deltaic sequences. Thermal maturities are too low to have generated much gas above the top of the Cody Shale (pl. 4). Based on gas isotope data, Johnson and Rice (1993) demonstrated the maturity of gases in the Wind River Formation, noted the lack of significant isotopic variation over large vertical distances, and concluded that gas in the shallow formations originated in older strata.

General Observations

When vitrinite reflectance (R_o) data are examined by formation, it can be seen that the near constant R_o segments in more marginal parts of the basin are offset from linearly increasing R_o segments in the deep basin — that is, R_o values at a given depth in a marginal well are less than R_o values at the same depth in a deep well. This offset is present in strata from the Mesaverde Formation upward into the lower part of the Fort Union Formation (figs. 3*C*, 3*D*, and 3*E*), but is not present in the Waltman Shale and Shotgun Members (fig. 3*F*). It is apparent that temperatures were systematically lower in the more marginal areas than in the deep basin at the time of maximum heating and that the normal temperature gradient was significantly perturbed.

The temperature gradient increases steadily from the basin margins into the north-central part of the basin, with rather erratic variations in the western part of the basin (map on pl. 3). High temperatures and high thermal gradients are present below the top of the lower part of the Fort Union in the north-central area. Hot spots and cold spots located in folded and faulted areas around the periphery of the basin are probably due to ground-water flow.

Water salinities in the Fort Union and Lance Formations increase from less than 5,000 ppm in the southern part of the basin to a range of 5,000 to 10,000 ppm in the deep basin to the north (fig. 4). The northward increase of salinity with increasing depth is interrupted by areas of high salinity (>10,000 ppm) waters (fig. 4).

Sonic velocity decreases, which are considered indicators of a combination of paleo-overpressure and present-day overpressure, are greatest in the northern and eastern wells. In addition, a well in the Pavillion gas system also shows one of the greatest velocity decreases in the basin. Sonic velocity decreases are least in the southeast and south. Wells in the west and southwest display low sonic velocity decreases in the upper shale in the Cody Shale, but the velocity decreases in the Thermopolis Shale are among the greatest in the basin. In other words, the apparent increase of overpressure with depth is notably high in the western and southwestern wells.

The water-gas ratio is independent of cumulative gas production, and also is not correlative with geologic formation (fig. 8). Instead, water production varies greatly from area to area, ranging from less than 1 to more than 100 bbl/MMCF (table 2 and fig. 8).

These disparate observations regarding fluids, pressures, and temperatures in the Wind River Basin are the result of a complex geologic history. Further progress in unraveling the geologic history of the basin requires that the data be integrated and modeled with basin stratigraphy (Johnson and others, 1996; Finn, Chapter 9, this CD-ROM), structural setting (Keefer, 1970), and burial history (Roberts and others, Chapter 6, this CD-ROM).

Acknowledgments

The pressure, temperature, and fluid data from drillstem tests were provided by the Wetterhorn Company; digital well logs were provided by Centerline Data. Tom Finn tabulated

bottom-hole temperatures in the Madden area and compiled a structural cross section for this report (see fig. 10). Depths of formation boundaries were determined from well logs by Ron Johnson, Tom Finn, Steve Roberts, and Mark Kirschbaum; Troy Cook provided estimates of ultimate gas recovery.

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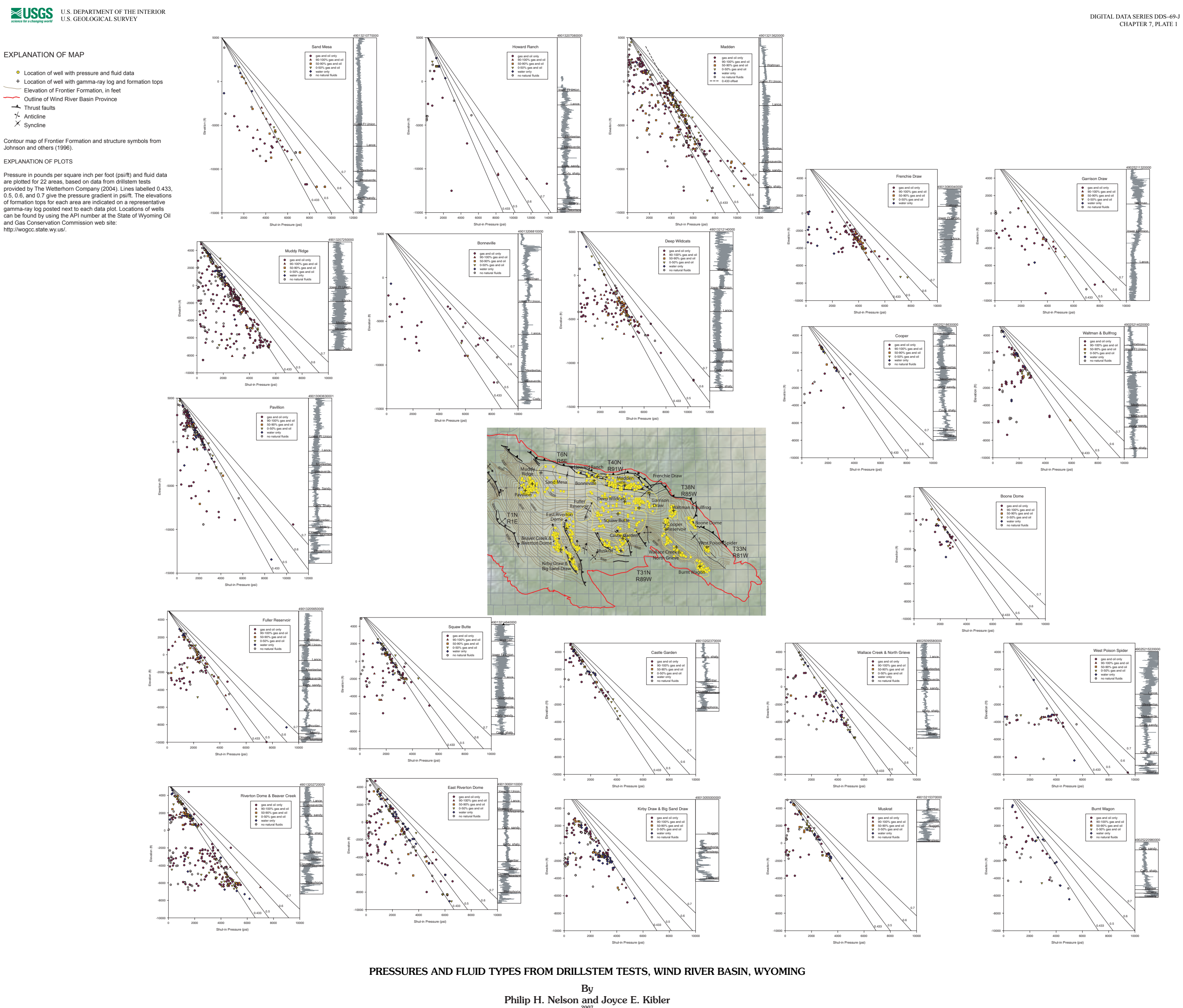

Plate 1. Pressures and fluid types from drillstem tests. (Click on image to view and print full size).

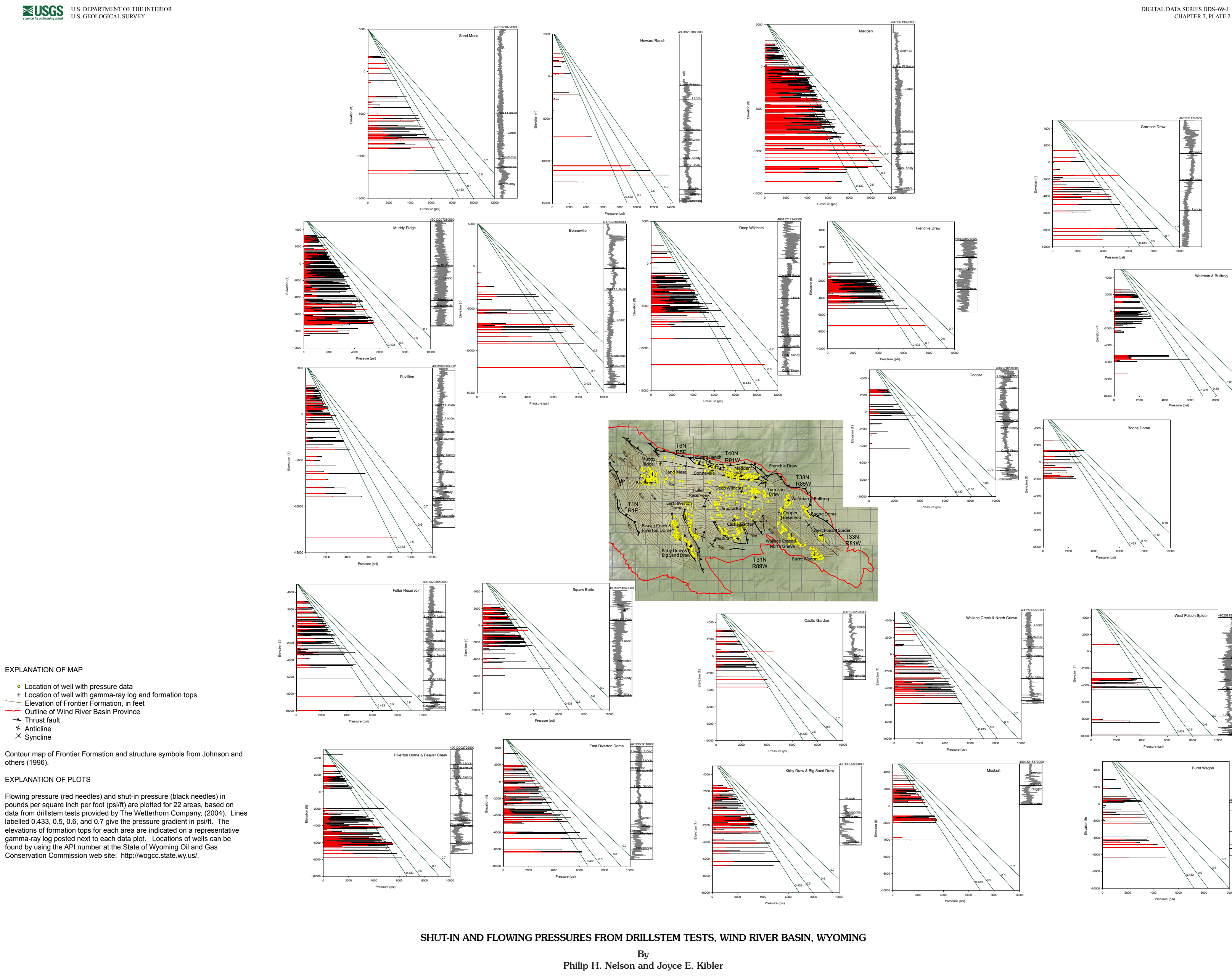

Plate 2. Shut-in and flowing pressures from drillstem tests. (Click on image to view and print full size).

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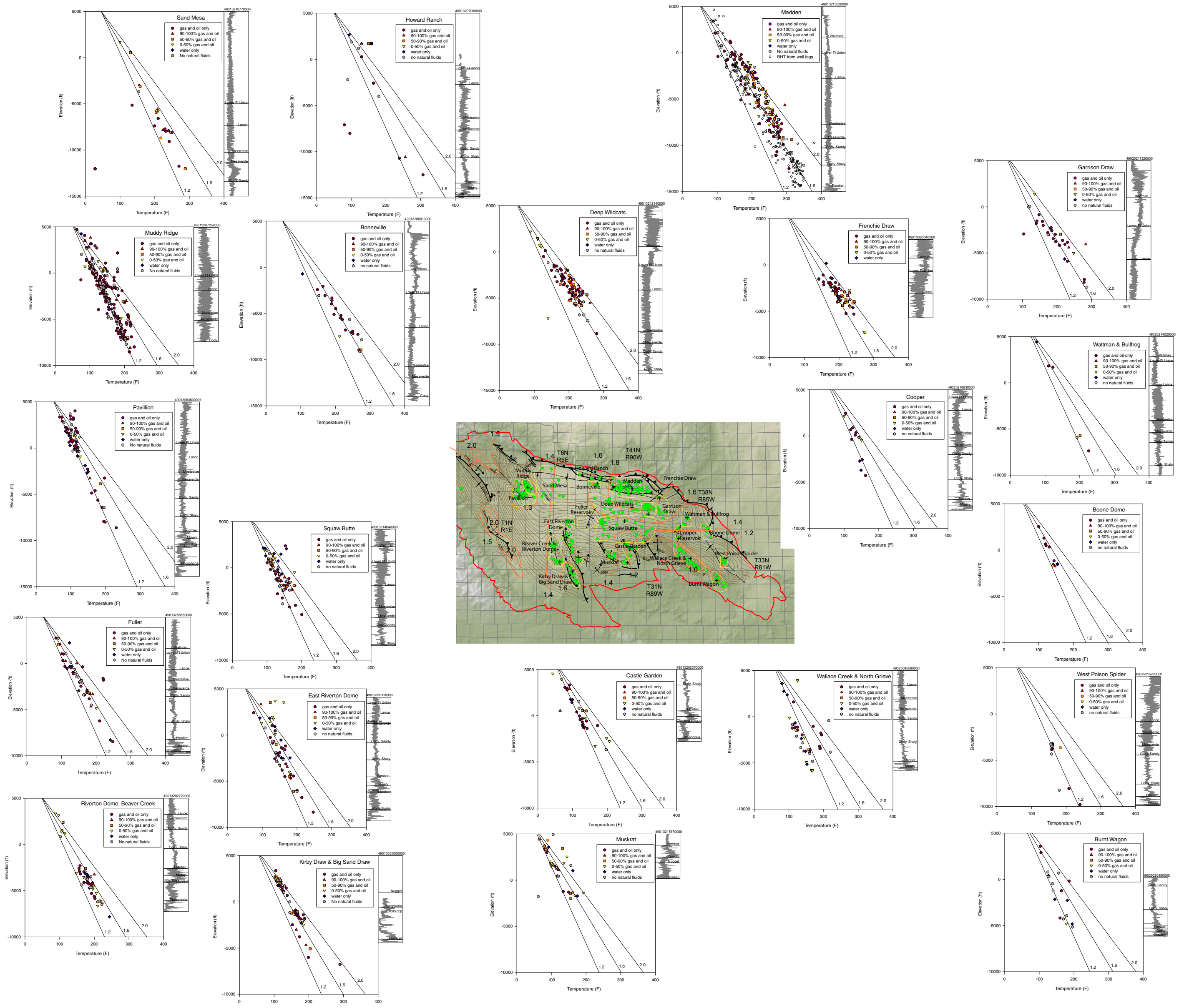
CHAPTER 7, PLATE 3



EXPLANATION OF MAP

- Location of well with pressure and fluid data
- Location of well with gamma-ray log and formation tops
- 1.4 Temperature gradient in °F per 100 ft
- Elevation of Frontier Formation, in feet
- Outline of Wind River Basin Province
- Thrust fault
- Anticline
- Syncline

Contour map of Frontier Formation and structural symbols from Johnson and others (1996).

EXPLANATION OF PLOTS

Temperature in degrees Fahrenheit (°F) and fluid data are plotted for 22 areas, based on data from drillstem tests provided by The Wetterhorn Company (2004). BHT is bottom-hole temperature from well log headers. Lines labelled 1.2, 1.6, and 2.0 represent geothermal gradients in °F per 100 ft. The elevations of formation tops for each area are indicated on a representative gamma-ray log posted next to each data plot. Locations of wells can be found by using the API number at the State of Wyoming Oil and Gas Conservation Commission web site: http://wogcc.state.wy.us/.

TEMPERATURES OF FLUIDS RECOVERED FROM DRILLSTEM TESTS, WIND RIVER BASIN, WYOMING
By
Philip H. Nelson and Joyce E. Kibler
2007

Plate 3. Temperatures of fluids recovered from drillstem tests. (Click on image to view and print full size).

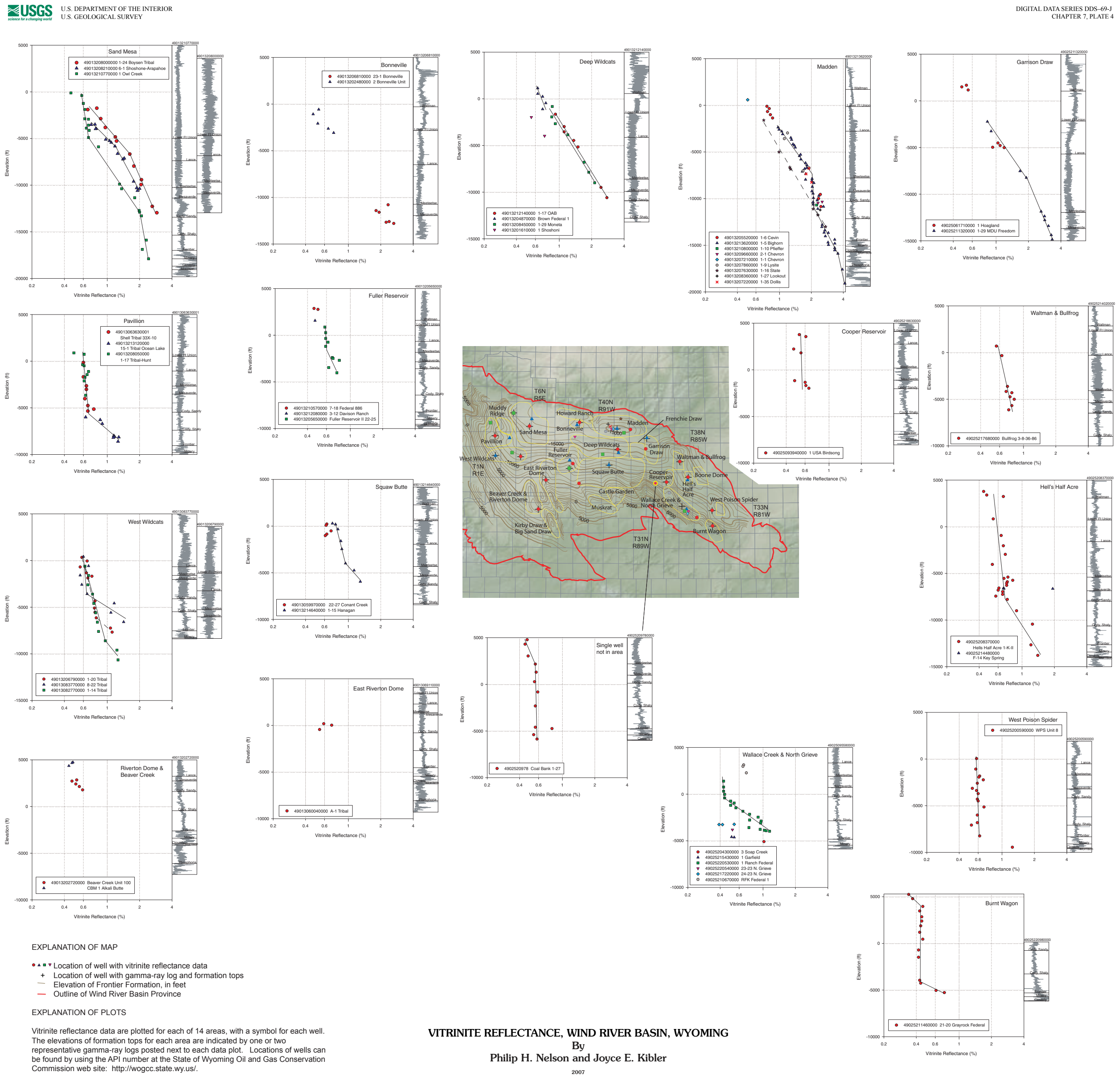


Plate 4. Vitrinite reflectance. (Click on image to view and print full size).

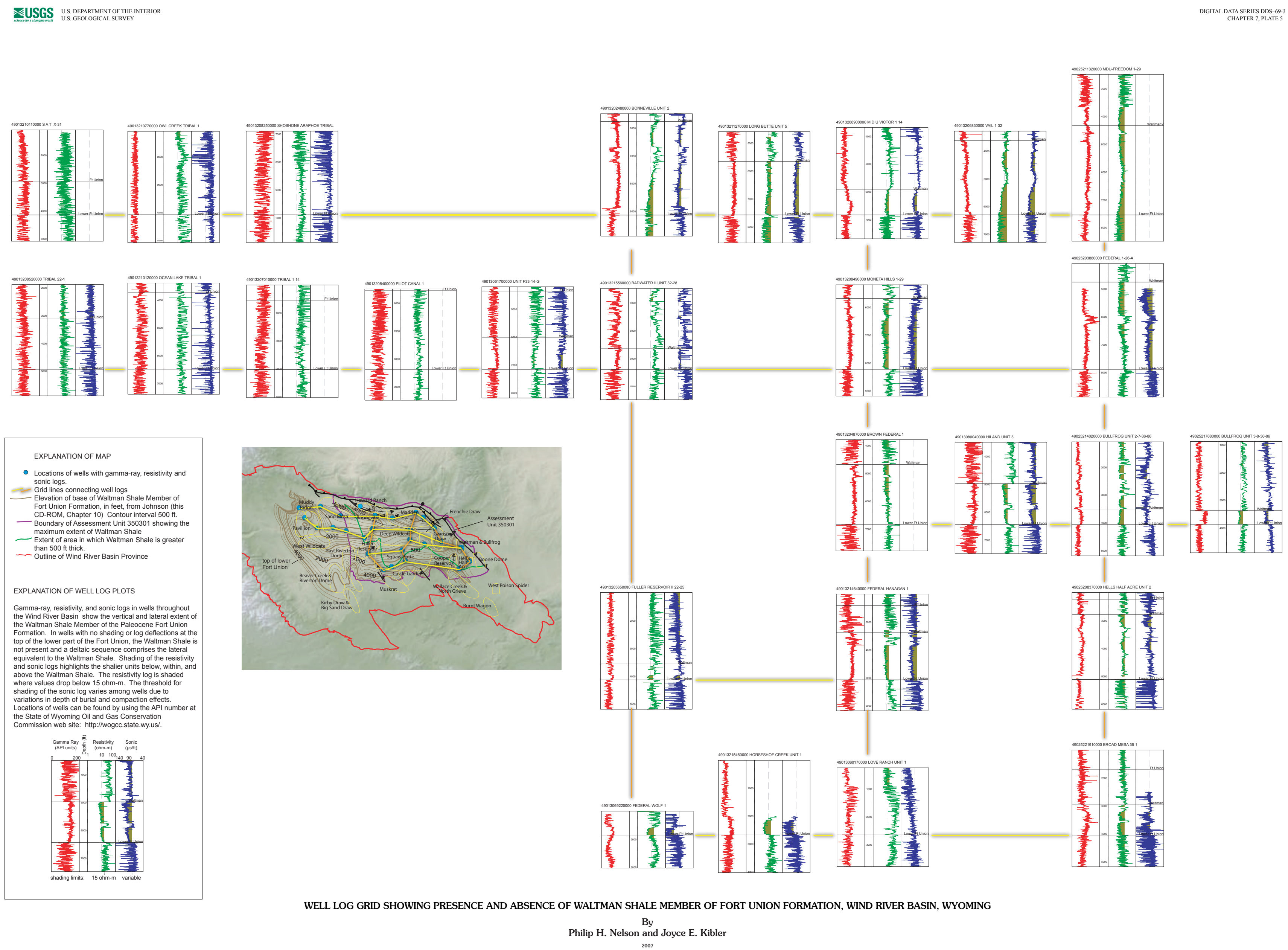


Plate 5. Well log grid showing presence and absence of Waltman Shale Member of Fort Union Formation. (Click on image to view and print full size).

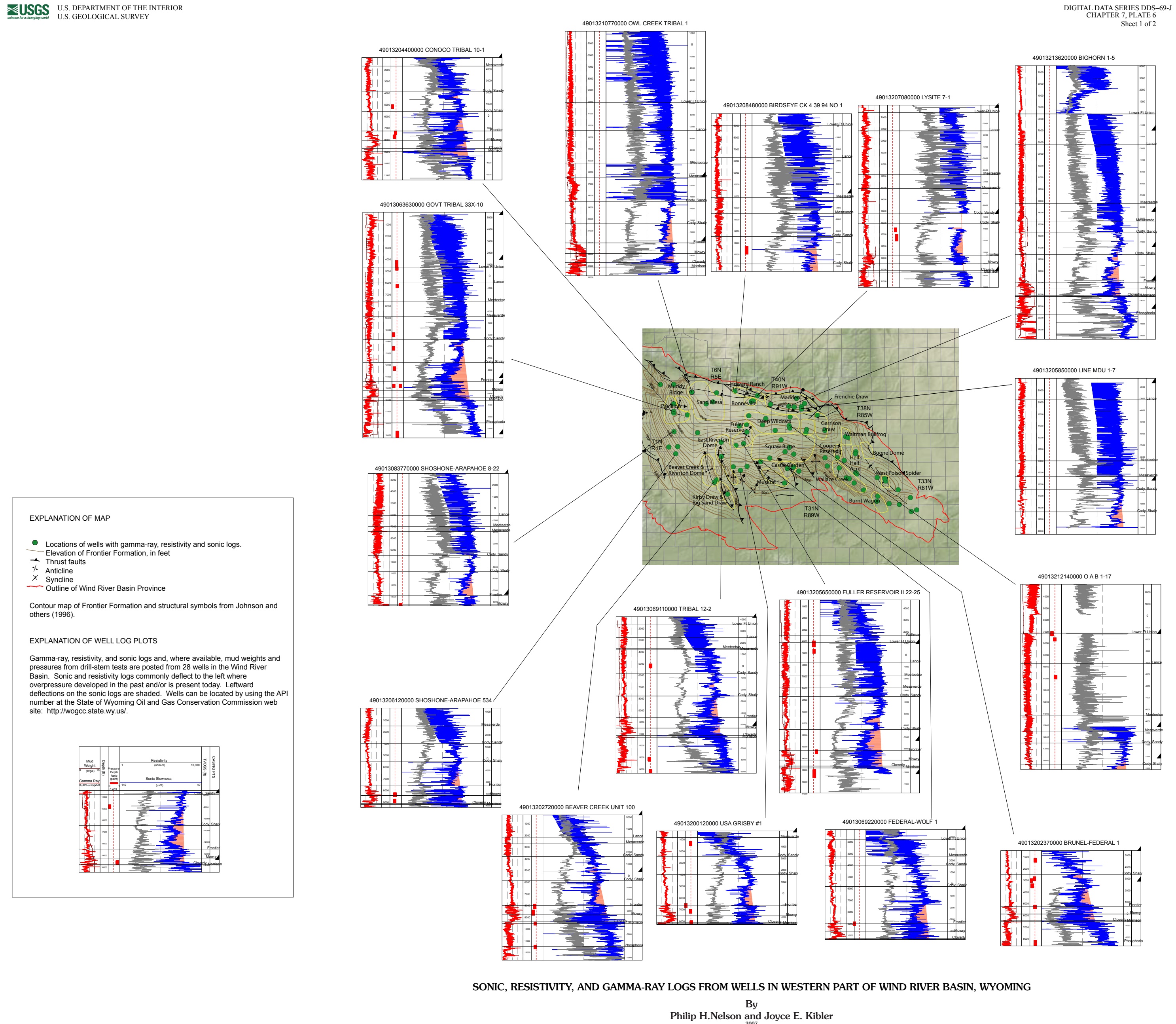


Plate 6, sheet 1. Sonic, resistivity, and gamma-ray logs from wells in western part of Wind River Basin, Wyoming. (Click on image to view and print full size).

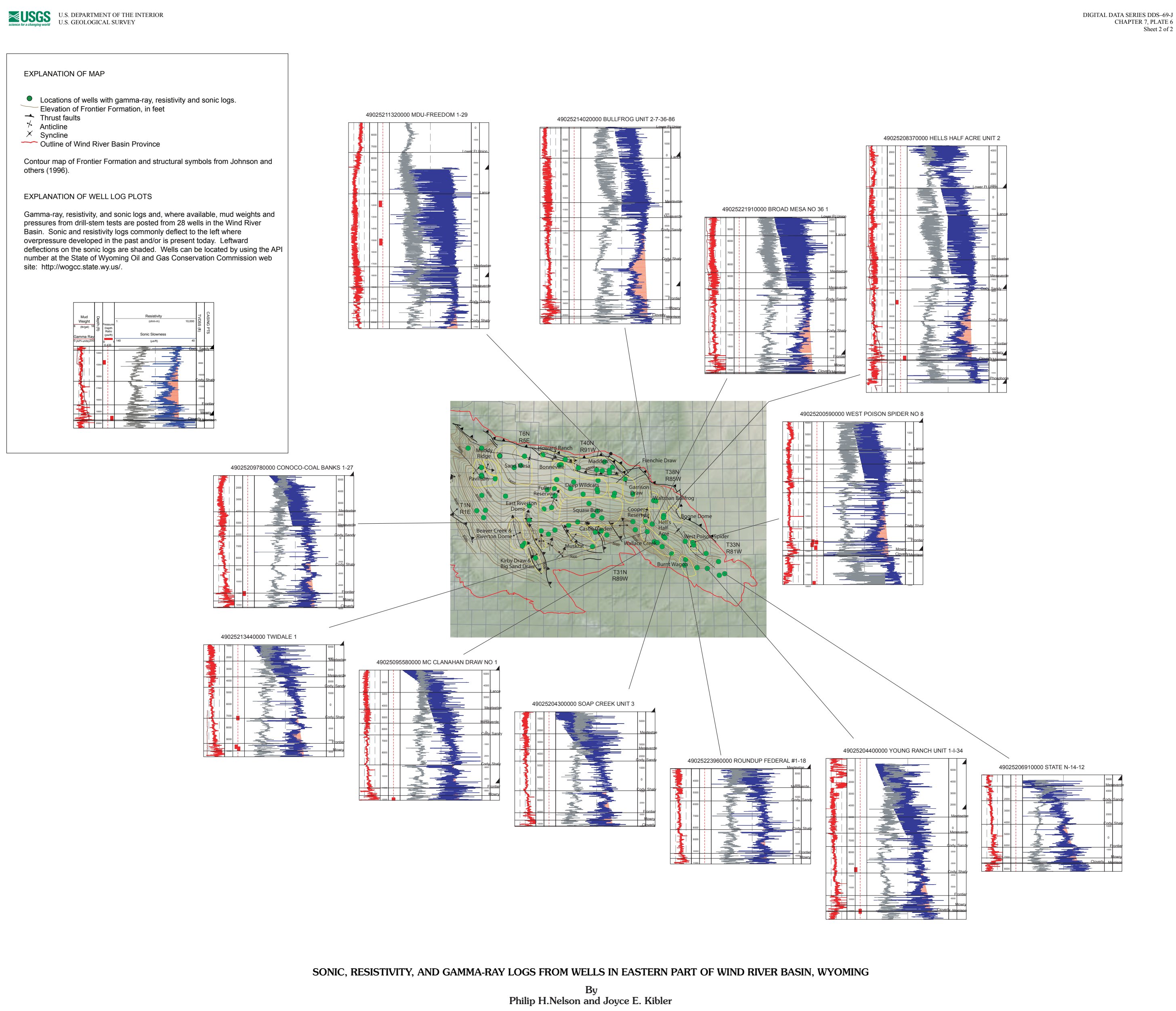


Plate 6, sheet 2. Sonic, resistivity, and gamma-ray logs from wells in eastern part of Wind River Basin, Wyoming. (Click on image to view and print full size).

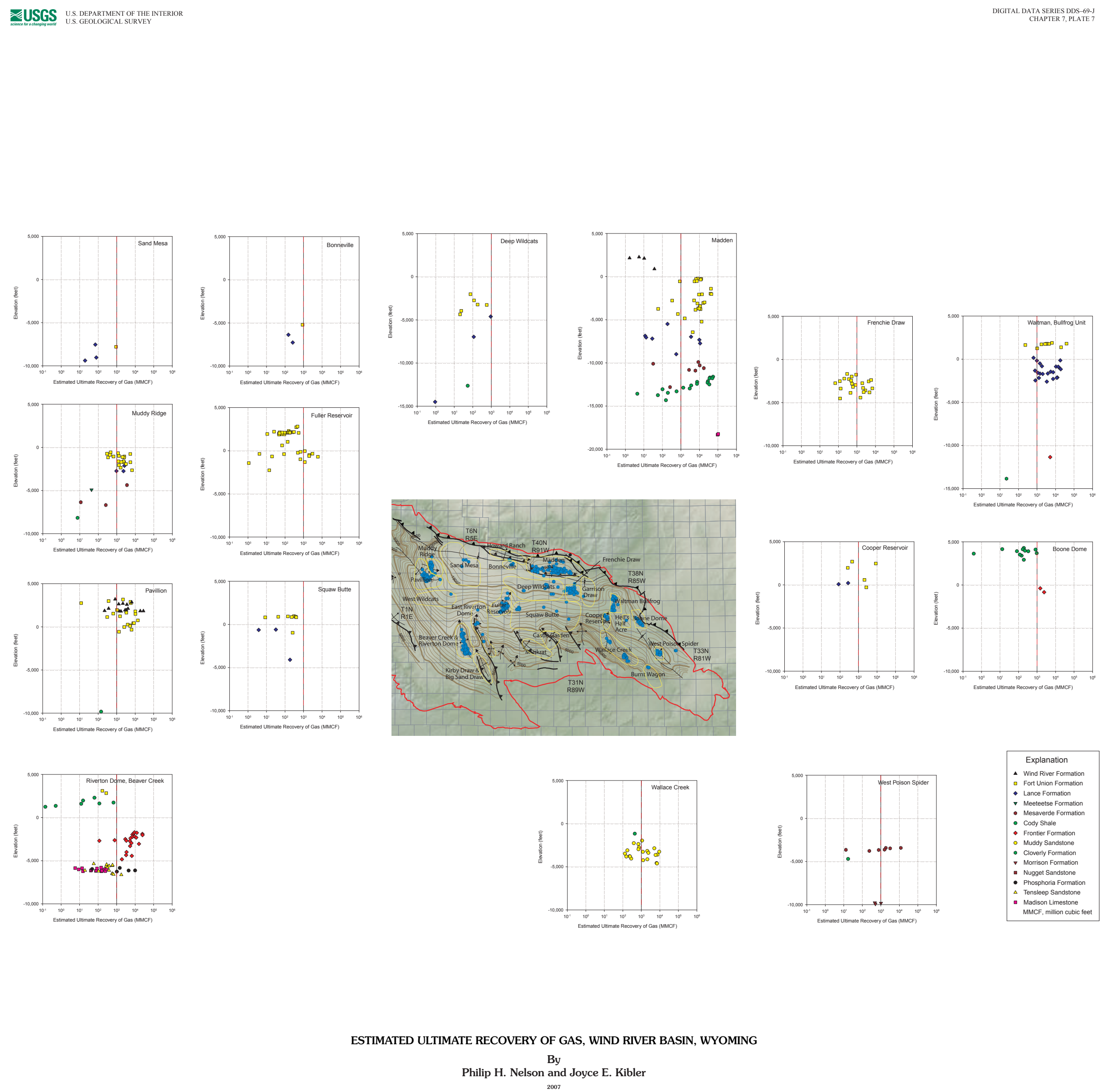


Plate 7. Estimated ultimate recovery of gas. (Click on image to view and print full size).

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