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MAJOR OIL PLAYS IN UTAH AND VICINITY

Submitted by:
Utah Geological Survey
1594 West North Temple, Suite 3110
P.O. Box 146100
Salt Lake City, Utah 84114-6100
Ph.: (801) 537-3300/Fax: (801) 537-3400

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Thomas C. Chidsey, Jr., Compiler and Editor

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Virginia Weyland, Project/Contract Manager
National Energy Technology Laboratory
1 West 3rd Street
Tulsa, OK 74103-3532

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ABSTRACT

Utah oil fields have produced over 1.33 billion barrels (211 million m^3) of oil and hold 256 million barrels (40.7 million m^3) of proved reserves. The 13.7 million barrels (2.2 million m^3) of production in 2002 was the lowest level in over 40 years and continued the steady decline that began in the mid-1980s. However, in late 2005 oil production increased, due, in part, to the discovery of Covenant field in the central Utah Navajo Sandstone thrust belt ("Hingeline") play, and to increased development drilling in the central Uinta Basin, reversing the decline that began in the mid-1980s. The Utah Geological Survey believes providing play portfolios for the major oil-producing provinces (Paradox Basin, Uinta Basin, and thrust belt) in Utah and adjacent areas in Colorado and Wyoming can continue this new upward production trend. Oil plays are geographic areas with petroleum potential caused by favorable combinations of source rock, migration paths, reservoir rock characteristics, and other factors. The play portfolios include descriptions and maps of the major oil plays by reservoir; production and reservoir data; case-study field evaluations; locations of major oil pipelines; identification and discussion of land-use constraints; descriptions of reservoir outcrop analogs; and summaries of the state-of-the-art drilling, completion, and secondary/tertiary recovery techniques for each play.

The most prolific oil reservoir in the Utah/Wyoming thrust belt province is the eolian, Jurassic Nugget Sandstone, having produced over 288 million barrels (46 million m^3) of oil and 5.1 trillion cubic feet (145 billion m^3) of gas. Traps form on discrete subsidiary closures along major ramp anticlines where the depositionally heterogeneous Nugget is also extensively fractured. Hydrocarbons in Nugget reservoirs were generated from subthrust Cretaceous source rocks. The seals for the producing horizons are overlying argillaceous and gypsiferous beds in the Jurassic Twin Creek Limestone, or a low-permeability zone at the top of the Nugget. The Nugget Sandstone thrust belt play is divided into three subplays: (1) Absaroka thrust – Mesozoic-cored shallow structures, (2) Absaroka thrust – Mesozoic-cored deep structures, and (3) Absaroka thrust – Paleozoic-cored shallow structures. Both of the Mesozoic-cored structures subplays represent a linear, hanging wall, ramp anticline parallel to the leading edge of the Absaroka thrust. Fields in the shallow Mesozoic subplay produce crude oil and associated gas; fields in the deep subplay produce retrograde condensate. The Paleozoic-cored structures subplay is located immediately west of the Mesozoic-cored structures subplays. It represents a very continuous and linear, hanging wall, ramp anticline where the Nugget is truncated against a thrust splay. Fields in this subplay produce nonassociated gas and condensate. Traps in these subplays consist of long, narrow, doubly plunging anticlines. Prospective drilling targets are delineated using high-quality, two-dimensional and three-dimensional seismic data, forward modeling/visualization tools, and other state-of-the-art techniques. Future Nugget Sandstone exploration could focus on more structurally complex and subtle, thrust-related traps. Nugget structures may be present beneath the leading edge of the Hogsback thrust and North Flank fault of the Uinta uplift.

The Jurassic Twin Creek Limestone play in the Utah/Wyoming thrust belt province has produced over 15 million barrels (2.4 million m^3) of oil and 93 billion cubic feet (2.6 billion m^3) of gas. Traps form on discrete subsidiary closures along major ramp anticlines where the low-porosity Twin Creek is extensively fractured. Hydrocarbons in Twin Creek reservoirs were generated from subthrust Cretaceous source rocks. The seals for the producing horizons are overlying argillaceous and clastic beds, and non-fractured units within the Twin Creek. The Twin Creek Limestone thrust belt play is divided into two subplays: (1) Absaroka thrust –

Mesozoic-cored structures and (2) Absaroka thrust – Paleozoic-cored structures. The Mesozoic-cored structures subplay represents a linear, hanging wall, ramp anticline parallel to the leading edge of the Absaroka thrust. Fields in this subplay produce crude oil and associated gas. The Paleozoic-cored structures subplay is located immediately west of the Mesozoic-cored structures subplay. It represents a very continuous and linear, hanging wall, ramp anticline where the Twin Creek is truncated against a thrust splay. Fields in this subplay produce nonassociated gas and condensate. Traps in both subplays consist of long, narrow, doubly plunging anticlines.

The Jurassic Navajo Sandstone Hingeline play is the only petroleum play in the central Utah thrust belt. The 2004 discovery of Covenant field in the Hingeline (central Utah thrust belt) changed the oil development potential in the play from hypothetical to proven. The original oil in place is estimated at 100 million barrels (15.9 million m^3); the estimated recovery factor is 40 to 50%. Traps in the central Utah thrust belt include anticlines associated with latest Jurassic through early Tertiary thrust imbricate and duplex structures, positioned near Middle Jurassic extension faults. The Navajo Sandstone reservoir was deposited in an extensive dune field that extended from present-day Wyoming to Arizona. The principal regional seal for the Lower Jurassic Navajo producing zones consists of salt, gypsum, mudstone, and shale of the overlying Jurassic Arapien Shale. Hydrocarbons were likely generated from Mississippian source rocks in Late Cretaceous to early Tertiary time. Future exploration in the central Utah thrust belt should focus on Paleozoic-cored, blind, thrust structures east of the exposed Charleston-Nebo and Pahvant thrusts. The lack of associated gas at Covenant field suggests the possibility that gas-charged traps may be present in the play area because the gas may have been driven off early during migration from sediment or thrust-plate loading.

Oil and associated gas production in the Laramide-age Uinta Basin is mostly from the Paleocene and Eocene Green River and Colton/Wasatch Formations, which were deposited in and around ancestral Lake Uinta. The Conventional Northern Uinta Basin and Deep Uinta Basin Overpressured Continuous plays cover the northern Uinta Basin and have a dominantly northern sediment source. The Conventional Northern Uinta Basin play typically has drill depths ranging from 5000 feet (1500 m) to a maximum of 10,000 feet (3000 m). The play is divided into two subplays: (1) Conventional Bluebell subplay, and (2) Conventional Red Wash subplay. The Deep Uinta Basin Overpressured Continuous play is where the lower 2500 to 3000 feet (750-900 m) of the Green River and intertonguing Colton Formations has a pressured gradient >0.5 pounds per square inch/foot (11.3 kPa/m); fracturing is also a key reservoir property. The Conventional Southern Uinta Basin play has a dominantly southern sediment source and is divided into six subplays: (1) conventional Uteland Butte interval, (2) conventional Castle Peak interval, (3) conventional Travis interval, (4) conventional Monument Butte interval, (5) conventional Beluga interval, and (6) conventional Duchesne interval fractured shale/marlstone. The source rocks for the Uinta Basin plays are kerogen-rich shale and marlstone of the Green River Formation. Most of the oils are characterized as yellow or black wax. The Conventional Northern Uinta Basin and Deep Uinta Basin Overpressured Continuous play areas are being explored for Mesaverde Group and Mancos Shale gas reservoirs. The deeper drilling could result in the discovery of new oil fields in the overlying Green River Formation.

The Mississippian Leadville Limestone, a shallow, open-marine, carbonate-shelf deposit, is a major oil and gas reservoir in the Utah/Colorado Paradox Basin, having produced over 53 million barrels (8.4 million m^3) of oil and 845 billion cubic feet (23.9 billion m^3) of gas. Most Leadville production is from the Paradox fold and fault belt in basement-involved structural traps with closure on both anticlines and faults. The seals for the Leadville producing zones are the

overlying clastic beds of the Molas Formation and evaporite beds within the Paradox Formation, both Pennsylvanian in age. Hydrocarbons in Leadville reservoirs were likely generated from source rocks in the Paradox Formation and migrated into traps, primarily along fault planes and fractures. The Leadville Limestone has heterogeneous reservoir properties because of depositional facies with varying porosity and permeability, diagenetic effects, and fracturing. The early diagenetic history of the Leadville sediments, including some dolomitization (finely crystalline) and leaching of skeletal grains, resulted in low-porosity and/or low-permeablility rocks. Most of the porosity and permeability associated with Leadville hydrocarbon production at Lisbon field was developed during later, deep subsurface dolomitization (coarsely crystalline replacement and saddle [hydrothermal?] dolomite) and dissolution. Relatively low-cost surface geochemical surveys, hydrodynamic analysis, and epifluorescence techniques may identify potential Leadville hydrocarbon migration patterns and oil-prone areas.

The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play. The Paradox Formation has produced over 500 million barrels (80 million m^3) of sweet, paraffinic oil and 650 billion cubic feet of gas (18 billion m^3) from more than 70 fields. The main producing zones are referred to as the Desert Creek and Ismay. The Paradox Formation play is divided into four subplays: (1) fractured shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone. In Pennsylvanian time, the Paradox Basin was rapidly subsiding in a subtropical arid environment with a shallow-water carbonate shelf on the south and southwest margins of the basin that locally contained carbonate buildups, commonly phylloid-algal mounds. Trap types include stratigraphic, stratigraphic with some structural influence, combination stratigraphic/structural, and diagenetic. The Paradox Formation has heterogeneous reservoir properties because of depositional lithofacies with varying porosity and permeability, carbonate buildup (mound) relief and flooding surfaces (parasequence boundaries), and diagenetic effects. Mapping the Ismay-zone lithofacies delineates very prospective reservoir trends that contain productive carbonate buildups around anhydrite-filled intra-shelf basins. Mapping also indicates a relatively untested lithofacies belt of calcarenite carbonate deposits south and southeast of Greater Aneth field. Fractured-shale beds in the Pennsylvanian Paradox Formation are oil productive in the Paradox Basin fold and fault belt (northern Paradox Basin) of southwest Utah. The Cane Creek shale of the Paradox Formation is composed of marine carbonate, evaporite, and organic-rich shale beds. The Cane Creek is a fractured, self-sourced oil reservoir that is highly overpressured – an ideal target for horizontal drilling.

Production-scale outcrop analogs provide an excellent view of reservoir petrophysics, facies characteristics, and boundaries contributing to the overall heterogeneity of reservoir rocks. They can be used as a “template” for evaluation of data from conventional core, geophysical and petrophysical logs, and seismic surveys. When combined with subsurface geological and production data, these outcrop analogs can improve (1) development drilling and production strategies such as horizontal drilling, (2) reservoir-simulation models, (3) reserve calculations, and (4) design and implementation of secondary/tertiary oil recovery programs and other best practices used in the oil fields of Utah and vicinity. The Jurassic Nugget/Navajo Sandstone was deposited in an extensive dune field that extended from Wyoming to Arizona. Outcrop analogs are found in the stratigraphically equivalent Navajo Sandstone of southern Utah which displays large-scale dunal cross-strata with excellent reservoir properties and interdunal features such as oases, wadi, and playa lithofacies with poor reservoir properties. The best outcrop analogs for Twin Creek reservoirs are found at Devils Slide and near the town of Peoa, Utah, where fractures

in dense, homogeneous non-porous limestone beds are in contact with the basal siltstone units (containing sealed fractures) of the overlying units. Outcrop analogs in the Tertiary Green River Formation for the Deep Uinta Basin Overpressured Continuous play in central Utah, provide good examples of deposits shed off the western highlands into Lake Uinta. An outcrop analog for the major oil reservoirs in the Conventional Northern Uinta Basin play is exposed along Raven Ridge in the northeastern Uinta Basin; these exposures display landward to lakeward facies transitions. Outcrop analogs for the major oil reservoirs in the Conventional Southern Uinta Basin play are well exposed in Willow Creek, Indian, and Nine Mile Canyons in the south-central Uinta Basin. Depositional environments include isolated fluvial, stacked channel, and distributary-channel channels; shallow-water mudflats; shallow open-lacustrine environments; and deeper offshore. Fractures can be observed in the Green River Formation in Indian Canyon and throughout the surface exposures in the Duchesne field along the Duchesne fault zone. The shallow marine, Mississippian Leadville Limestone is a major oil and gas reservoir in the Paradox Basin of Utah and Colorado. Excellent outcrops of Mississippian Leadville-equivalent rocks are found in the Madison Limestone along the south flank of the Uinta Mountains, Utah, and in the Redwall Limestone in the Marble Canyon area of Grand Canyon National Park, Arizona. These formations contain zones of solution breccia, fractures, and facies variations. Hydrocarbons in the Pennsylvanian Paradox Formation are stratigraphically trapped in carbonate buildups (or phylloid-algal mounds). Similar carbonate buildups are exposed in the Paradox along the San Juan River of southeastern Utah. Reservoir-quality porosity may develop in the types of facies associated with buildups such as troughs, detrital wedges, and fans, identified from these outcrops.

Land-use constraints within oil plays are a critical concern to current and potential operators exploring and developing petroleum resources in Utah and vicinity. Land classification maps and land ownership acreage summaries for Utah's major oil-producing provinces portray multiple types of surface and/or mineral ownership. These maps and summaries will help guide petroleum companies in planning exploration and land-acquisition strategies, pipeline companies and gas processors in planning future facilities and pipeline extensions, and government agencies in decision-making processes. Substantial land, environmental, regulatory, and mineral leasing information is available on all of the federal Web sites involved in oil and gas leasing and/or regulation. To a lesser extent similar information is available on most state Web sites. We have compiled locations and documented the major land and mineral ownership types in each oil-producing province; identified the federal, state, county, and other private and non-profit agencies involved in the environmental analysis, leasing, and development of oil and gas resources; and provided an overview and listing of pertinent data, documents, and research tools that might be helpful in understanding the oil and gas industry, primarily in Utah, but also in Arizona, Colorado, and Wyoming. The major plays in the oil-producing provinces encompass nearly 15.1 million acres (6.1 million ha) and include almost all of the potential oil- and gas-bearing land in Utah. Mineral ownership and management, including leasing, is divided primarily among federal, state, and private interests. Private interests also include Native American Reservation lands and may include Native American mineral ownership outside an Indian Reservation. Mineral ownership patterns vary among the provinces and dominant ownership is somewhat different in each area. Federal ownership is multifaceted in that while the mineral estate is managed by the BLM, the overlying surface estate might be managed by other federal agencies. The surface estate may be privately owned, creating a split estate, which is very common in the Western U.S.

Horizontal drilling in Utah thrust belt fields targets the heterogeneous Twin Creek Limestone and Nugget Sandstone reservoirs. Fractures and lithologic variations create potential undrained compartments ideally suited for horizontal drilling, particularly in the Watton Canyon Member of the Twin Creek. Horizontal wells should generally be drilled perpendicular to the dominant orientation of open fractures, and above and parallel to the low-proved oil or oil/water contacts. Horizontal drilling programs at Pineview, Lodgepole, and Elkhorn Ridge fields, Utah, and Painter Reservoir and Ryckman Creek Fields, Wyoming, in the thrust belt successfully extended the productive life of the fields. These fields were at an advanced stage of depletion when the horizontal drilling began. At Painter Reservoir field a tertiary, miscible nitrogen-injection program is being conducted to raise the reservoir pressure to miscible conditions. Supplemented with water injection, the ultimate recovery will be 113 million bbls (18 million m^3) of oil (a 68 percent recovery factor over a 60-year period). Condensate production is common in Absaroka thrust - Mesozoic-cored deep structures. In retrograde condensate reservoirs, the fluid changes from a single-phase rich gas to a two-phase gas and liquid mixture when the pressure drops below the dew-point pressure. Without pressure maintenance, the retrograde condensate remains in the reservoir and wells are less productive. The Nugget Sandstone in Anschutz Ranch East field on the Utah/Wyoming border is a major retrograde reservoir where pressure maintenance operations (using an injection of nitrogen and wet gas) have successfully maximized recovery. At Covenant field in the central Utah thrust belt, wells are drilled to the Navajo Sandstone from three pads and deviated to avoid rugged topography. Future Covenant secondary and tertiary recovery programs may include nitrogen injection and/or a carbon dioxide flood.

In the Uinta Basin, the Northern Conventional Uinta Basin and Deep Uinta Basin Overpressured Continuous plays current production practices (in the Altamont-Bluebell-Cedar Rim field trend) will leave a significant amount of oil unproduced. Identifying which beds actually contribute to the production and the role that naturally occurring fractures play in the reservoir, remains a major trend-development problem. A major resource potential may be in recompletions of the current wells. Well completions typically consist of perforating 40 or more beds. As a result, many of the beds may never have received adequate stimulation. We recommend using cased-hole logs to identify by-passed oil and selectively stimulating individual beds to recover significant amounts of additional oil.

In the Altamont-Bluebell-Cedar Rim field trend, staging acid treatments over smaller (500-foot [150 m]) intervals and greatly increasing the amount of diversion material used has been shown to be effective for maximizing production. A bed-scale completion technique could be effective in older wells nearing depletion where a larger staged completion is no longer economical. Therefore, in older wells it is recommended that treatment of a few individual beds be attempted using a dual packer tool. This way, only the few beds with remaining oil potential are acidized, reducing the size of the treatment needed, and providing more effective stimulation of the beds with remaining potential. Hydrochloric acid has been the recommended treating fluid although many operators have begun to use a proppant stimulation. Good diversion is also critical to treating the entire interval and a high-enough pumping rate must be maintained to carry the diverting agent. A pumping rate between 8 and 12 barrels per minute (1.3-1.9 m^3/min) with proper gelling agents in the fluid will divert the fluid to the perforated intervals, and maintain a reasonable well-head-treating pressure. High-rate hydraulic fracture treatments should be considered on newer wells. The dual-burst, thermal-decay time and dipole-shear anisotropy logs are reliable tools for evaluating remaining hydrocarbon potential and fracture

density in a cased-hole well that has been producing oil for many years. This type of data can be used to identify potentially productive beds that are not perforated in older wells, eliminate the acidizing of previously perforated beds that have little to no potential, and determine if the acid-fracture treatment is hydraulically fracturing the formation.

Secondary and tertiary recovery methods have not been attempted in the Deep Uinta Basin Overpressured Continuous play area. Fractures, the dominant reservoir property, can cause early breakthrough of any injected fluid or gas which can then move beyond the intended secondary recovery unit. Secondary and tertiary recovery methods generally require a high density of wells to be effective. The Deep Uinta Basin Overpressured Continuous play area has been developed with two wells per section (as of November 2008) and in many areas at least one of those wells has already been plugged and abandoned. As a result, any secondary or tertiary recovery method would require a significant amount of additional deep drilling.

Best practices used in oil fields of the eastern Uinta Basin consist of conversion of all geophysical well logs into digital form, running small fracture treatments, fingerprinting oil samples from each producing zone, running spinner surveys biannually, mapping each producing zone, and drilling on 80-acre (32-ha) spacing. These practices ensure that induced fractures do not extend vertically out of the intended zone, determine the percentage each zone contributes to the overall production of the well, identify areas that may be by-passed by a waterflood, and prevent rapid water breakthrough.

In the Conventional Southern Uinta Basin play, optimal drilling, development, and production practices consist of: (1) owning drilling rigs and frac holding tanks; (2) perforating sandstone beds with more than 8% neutron porosity and stimulating with separate fracture treatments; (3) placing completed wells on primary production using artificial lift; (4) converting wells relatively soon to secondary waterflooding to maintain reservoir pressure above the bubble point and maximize oil recovery; (5) developing waterflood units using an alternating injector – producer pattern on 40-acre (16-ha) spacing (as of 2008 some 8-spot, 20-acre [8-ha]) pilot areas have shown to be successful); and (6) recompleting producing wells by perforating all beds that are productive in the waterflood unit.

In the Paradox Basin, wells in Leadville fields were drilled with air or fresh-water mud to the top of the Pennsylvanian salt, after which a natural brine or salt-base mud was typically used to total depth. These wells were completed by perforating at four shots per foot and acid stimulation of porosity zones. A thick hydrocarbon column at Lisbon field contains a gas cap and oil ring. Associated gas was reinjected into the gas cap to maintain reservoir pressure and maximize the oil recovery. Horizontal drilling technology was not readily available when Lisbon field and other Leadville fields were discovered and developed. If horizontal technology had been available, Leadville fields could have been developed with fewer wells (especially in environmentally sensitive areas), and would have resulted in a greater ultimate oil recovery. Lithologic variations due to facies changes, diagenetically increased porosity zones due to dolomitzation, and fractures create potential undrained compartments ideally suited for horizontal drilling in the Leadville-producing fields. Drilling techniques should include new wells, and horizontal, often multiple and stacked, laterals from existing vertical wells.

The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play. The Paradox Formation Play is divided into four subplays: (1) fractured Cane Creek shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone. Three significant late-term development practices were, or could be, employed in the later development of fields in the Paradox Formation play to

enhance the ultimate recovery of oil: (1) horizontal drilling, (2) waterflooding, and (3) CO_2 flooding. Horizontal drilling techniques include new wells and horizontal, often multiple, laterals from existing vertical wells. Depositional lithofacies are targeted in both the Ismay and Desert Creek zones where, for example, multiple buildups can be penetrated with two opposed sets of stacked, parallel horizontal laterals. Other targets include multiple zones of diagenetically enhanced or fractured intervals. Horizontal drilling has increased the probability of encountering the near-vertical fractures, has resulted in numerous new field discoveries, and has greatly improved the success rate in the Cane Creek shale.

In the eastern Paradox Basin, Colorado, optimal drilling, development, and production practices consist of increasing the mud weight during drilling operations before penetrating the overpressured Desert Creek zone; centralizing treatment facilities; and mixing produced water from pumping oil wells with non-reservoir water and injecting the mixture into the reservoir downdip to reduce salt precipitation, dispose of produced water, and maintain reservoir pressure to create what amounts to as a low-cost waterflood.

Waterflooding is the most common type of secondary oil recovery technique in the Paradox Basin. Depth, drive mechanisms, and water, oil, and gas saturations are major factors to determine candidate reservoirs for waterflood programs. Water-drive reservoirs are usually not good candidates for waterflooding. The drive mechanisms for most Paradox reservoirs are solution gas, gas expansion, fluid expansion, or pressure depletion. The waterflood program in the Aneth unit of Greater Aneth field now uses horizontal laterals in a line-drive injection pattern which improves both areal and vertical sweep efficiencies over vertical wells.

Carbon dioxide (CO_2) flooding is relatively low risk, significantly increases oil recovery, and extends the life of a field by 20 to 30 years. Ultimate oil recovery may increase by over 40% with CO_2 flooding (8 to 16% due to CO_2 flooding alone). Carbon dioxide miscibility needs to be attainable over a major portion of the reservoir; that includes widespread good injectivity and reservoir connectivity. Prospective CO_2 flooding candidates should first perform well during waterflood programs. If production water cut reaches 98%, especially during waterfloods, operators likely lose the ability to borrow capital against future production and CO_2 flooding becomes uneconomic. It is also important to recognize that CO_2 prices fluctuate in response to crude oil prices. Carbon dioxide sources include McElmo Dome field in southwest Colorado, drilling locally, and emissions from coal-fired power plants. Carbon dioxide flooding began in the McElmo Creek unit of Greater Aneth in 1985. The production response was between one and two years through a water-alternating-gas program. Oil production increased from 5500 barrels of oil per day (BOPD) to 6500 BOPD (880-1030 m^3/d) peaking after a ten-year period. Incremental recovery from CO_2 flooding is estimated at 33 million barrels of oil (5.3 million m^3) or an incremental recovery efficiency of 9.3%. Horizontal wells in the Aneth unit may also be used for CO_2 flooding; however, horizontal laterals need to be oriented parallel to fault/fracture zones to prevent rapid breakthrough.

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Project Contributors

State Geologist and Director of the Utah Geological Survey

Richard G. Allis

Principal Investigator/Program Manager

Thomas C. Chidsey, Jr., Utah Geological Survey, Salt Lake City, Utah

Financial Officers

John Kingsley, Dan Kelly (now with the U.S. Department of Defense), Kathi Galusha, Utah Geological Survey, Salt Lake City, Utah

Task Contributing Scientists and Organizations

Roger L. Bon, Thomas Dempster, Hellmut H. Doelling, Thomas C. Chidsey, Jr., J. Wallace Gwynn, Michael D. Laine, Kevin McClure (now with Castle Inspection Services), Craig D. Morgan, Douglas A. Sprinkel, and Sharon Wakefield (retired), Utah Geological Survey, Salt Lake City, Utah

Bradley G. Hill and Michael Hebertson (now with Flying J), Utah Division of Oil, Gas and Mining, Salt Lake City, Utah

Richard Curtice, Halliburton Energy Services, Vernal, Utah

David E. Eby, Eby Petrography & Consulting, Inc., Denver, Colorado

Richard Jarrard, University of Utah, Salt Lake City, Utah

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EXECUTIVE SUMMARY

Utah oil fields have produced over 1.33 billion barrels (211 million m^3) of oil and hold 256 million barrels (40.7 million m^3) of proved reserves. The 13.7 million barrels (2.2 million m^3) of production in 2002 was the lowest level in over 40 years and continued the steady decline that began in the mid-1980s. However, in late 2005 oil production increased, due, in part, to the discovery of Covenant field in the central Utah Navajo Sandstone thrust belt ("Hingeline") play, and to increased development drilling in the central Uinta Basin, reversing the decline that began in the mid-1980s. The overall objectives of this study are to (1) continue adding new discoveries, (2) increase recoverable oil from existing field reservoirs, (3) prevent premature abandonment of numerous small fields, (4) increase deliverability through identifying the latest drilling, completion, and secondary/tertiary recovery techniques, and (5) reduce development costs and risk.

To achieve these objectives, the Utah Geological Survey produced play portfolios for the major oil-producing provinces (Paradox Basin, Uinta Basin, and thrust belt) in Utah and adjacent areas in Colorado and Wyoming. This research is partially funded by the Preferred Upstream Management Program (PUMPII) of the U.S. Department of Energy, National Energy Technology Laboratory (NETL) in Tulsa, Oklahoma.

A combination of depositional and structural events created the right conditions for oil generation and trapping in the major oil-producing provinces (Paradox Basin, Uinta Basin, and thrust belt) in Utah and adjacent areas in Colorado and Wyoming. Oil plays are specific geographic areas having petroleum potential due to favorable source rock, migration paths, reservoir characteristics, and other factors.

Major Plays

Jurassic Nugget Sandstone Thrust Belt Play

The most prolific oil reservoir in the Utah/Wyoming thrust belt province is the Jurassic Nugget Sandstone, having produced over 288 million barrels (46 million m^3) of oil and 5.1 trillion cubic feet (145 billion m^3) of gas. The Nugget Sandstone was deposited in an extensive dune field (an eolian environment) which extended from Wyoming to Arizona, and was comparable to the present Sahara in North Africa or the Alashan area of the Gobi in northern China. Playas, mudflats, or oases developed in interdune areas. Traps form on discrete subsidiary closures along major ramp anticlines where the Nugget is extensively fractured. Hydrocarbons in Nugget reservoirs were generated from subthrust Cretaceous source rocks. The seals for the producing horizons are overlying argillaceous and gypsiferous beds of the Jurassic Twin Creek Limestone or a low-permeability zone at the top of the Nugget Sandstone.

The Nugget Sandstone has heterogeneous reservoir properties because of (1) cyclic dune/interdune lithofacies with better porosity and permeability in certain dune morphologies, (2) diagenetic effects, and (3) fracturing. Identification and correlation of barriers and baffles to fluid flow, and recognition of fracture set orientations in individual Nugget reservoirs in the thrust belt is critical to understanding their effects on production rates, petroleum movement pathways, horizontal well plans, and pressure maintenance programs.

The Nugget Sandstone thrust belt play is divided into three subplays: (1) Absaroka thrust – Mesozoic-cored shallow structures, (2) Absaroka thrust – Mesozoic-cored deep structures, and

(3) Absaroka thrust – Paleozoic-cored shallow structures. Both Mesozoic-cored structures subplays represent a linear, hanging wall, ramp anticline parallel to the leading edge of the Absaroka thrust. Fields in the shallow Mesozoic subplay produce crude oil and associated gas; fields in the deep subplay produce retrograde condensate. The Paleozoic-cored shallow structures subplay is located immediately west of the Mesozoic-cored structures subplays. The subplay represents a very continuous and linear, hanging wall, ramp anticline also parallel to the leading edge of the Absaroka thrust. The eastern boundary of the subplay is defined by the truncation of the Nugget against a thrust splay. Fields in this subplay produce nonassociated gas and condensate. Traps in these subplays consist of long, narrow, doubly plunging anticlines.

Prospective drilling targets in the Nugget Sandstone thrust belt play are delineated using the following: high-quality, two-dimensional and three-dimensional seismic data, forward modeling/visualization tools, well control, dipmeter information, surface geologic maps, and incremental restoration of balanced cross sections to assess trap geometry. Determination of the timing of structural development, petroleum migration, entrapment, and fill and spill histories are critical to successful exploration. Future Nugget Sandstone exploration could focus on more structurally complex and subtle, thrust-related traps. Nugget structures may be present beneath the leading edge of the Hogsback thrust and North Flank fault of the Uinta uplift.

Jurassic Twin Creek Limestone Thrust Belt Play

The Jurassic Twin Creek Limestone in the Utah/Wyoming thrust belt province has produced over 15 million barrels (2.4 million m^3) of oil and 93 billion cubic feet (2.6 billion m^3) of gas. The Twin Creek Limestone was deposited in a shallow-water embayment south of the main body of a Middle Jurassic sea. Traps form on discrete subsidiary closures along major ramp anticlines where the low-porosity Twin Creek is extensively fractured. Hydrocarbons in Twin Creek reservoirs were generated from subthrust Cretaceous source rocks. The seals for the producing horizons are overlying argillaceous and clastic beds, and non-fractured units within the Twin Creek. Most oil and gas production is from perforated intervals in the Watton Canyon, upper Rich, and Sliderock Members of the Twin Creek Limestone. These members have little to no primary porosity in the producing horizons but exhibit secondary porosity in the form of fracturing.

The Twin Creek Limestone thrust belt play is divided into two subplays: (1) Absaroka thrust – Mesozoic-cored structures and (2) Absaroka thrust – Paleozoic-cored structures. The Mesozoic-cored structures subplay represents a linear, hanging wall, ramp anticline parallel to the leading edge of the Absaroka thrust. Fields in this subplay produce crude oil and associated gas. The Paleozoic-cored structures subplay is located immediately west of the Mesozoic-cored structures subplay. The subplay represents a very continuous and linear, hanging wall, ramp anticline also parallel to the leading edge of the Absaroka thrust. The eastern boundary of the subplay is defined by the truncation of the Twin Creek against a thrust splay. Fields in this subplay produce nonassociated gas and condensate. Traps in both subplays consist of long, narrow, doubly plunging anticlines.

Jurassic Navajo Sandstone Hingeline Play

The Jurassic Navajo Sandstone Hingeline play is the only petroleum play in the central Utah thrust belt. The 2004 discovery of Covenant field in the central Utah thrust belt changed

the oil development in the Utah Hingeline from hypothetical to proven. Traps in the central Utah thrust belt include anticlines associated with latest Jurassic through early Tertiary thrust imbricate and duplex structures, positioned near Middle Jurassic extension faults. The principal regional seal for the Lower Jurassic Navajo producing zones consists of salt, gypsum, mudstone, and shale of the overlying Jurassic Arapien Shale. Hydrocarbons were likely generated from Mississippian source rocks. The source rocks began to mature after loading by overriding of thrust plates during Late Cretaceous and early Tertiary time. Hydrocarbons were generated, expelled, and subsequently migrated into overlying traps, primarily along fault planes.

The Navajo Sandstone reservoir was deposited in same dune field as the Nugget Sandstone that extended from Wyoming to Arizona. The Navajo at Covenant field has 424 feet (139 m) of net pay, an average of 12% porosity, up to 100 millidarcies of permeability, an average water saturation of 38%, and a strong water drive. The original oil in place is estimated at 100 million barrels (15.9 million m^3); the estimated recovery factor is 40 to 50%.

Future exploration in the central Utah thrust belt should focus on Paleozoic-cored, blind, thrust structures east of the exposed Charleston-Nebo and Pahvant thrusts. The lack of associated gas at Covenant field suggests the possibility that gas-charged traps may be present in the play area because the gas may have been driven off early during migration from sediment or thrust-plate loading.

Uinta Basin Plays

Oil and gas production in the Laramide-age Uinta Basin is mostly from the Paleocene and Eocene Green River and Colton/Wasatch Formations. In early late Paleocene time, a large lake, known as ancestral Lake Uinta, developed in the basin. Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine sediments that make up the Green River Formation. Alluvial redbed and floodplain deposits that are laterally equivalent to, and intertongue with, the Green River form the Colton/Wasatch.

The U.S. Geological Survey defines two assessment units within the Green River Total Petroleum System in the Uinta Basin: the Deep Uinta Overpressured Continuous Oil Assessment Unit (Deep Uinta Basin Overpressured Continuous play in this report) and the Uinta Green River Conventional Oil and Gas Assessment Unit. The Conventional Oil and Gas Assessment Unit can be divided into plays having a dominantly southern sediment source (Conventional Southern Uinta Basin play) and plays having a dominantly northern sediment source (Conventional Northern Uinta Basin play).

The Conventional Northern Uinta Basin and Deep Uinta Basin Overpressured Continuous plays cover the northern Uinta Basin. The Conventional Northern Uinta Basin play typically has drill depths ranging from 5000 feet (1500 m) to a maximum of 10,000 feet (3000 m). The play is divided into two subplays: (1) Conventional Bluebell subplay, and (2) Conventional Red Wash subplay. The Deep Uinta Basin Overpressured Continuous play is delineated where the lower 2500 to 3000 feet (750-900 m) of the Green River and intertonguing Colton Formations are overpressured (gradient >0.5 pounds per square inch/foot [11.3 kPa/m]). The most rapid increase in reservoir pressure and most of the high-volume, overpressured oil production typically occurs at depths ranging from 11,000 to 14,000 feet (3400-4300 m).

In the Conventional Bluebell subplay, sandstone reservoirs typically have low porosity (8 to 12%) and low matrix permeability (0.01 to 10 millidarcies [mD]). Sandstone reservoirs in the Conventional Red Wash subplay have higher porosities (8 to 20%) and significantly higher

matrix permeabilities, commonly 50 to 500 mD. In the Deep Uinta Basin Overpressured Continuous play, production is fracture controlled in reservoir rocks which typically have very low (< 0.1 mD) matrix permeability. The reservoirs are fractured lenticular sandstone, shale, and marlstone deposited in the lacustrine and alluvial environments of Lake Uinta.

Fields in the Conventional Northern Uinta Basin play and Deep Uinta Basin Overpressured Continuous play produce crude oil with associated gas. Production from the Conventional Bluebell subplay cannot be accurately separated from the Deep Uinta Basin Overpressured Continuous play. The largest fields in the Conventional Red Wash subplay have produced 155.9 million barrels (24.8 million m^3) of oil and 474.6 billion cubic feet of gas (BCFG) (13.4 BCMG). The Deep Uinta Basin Overpressured Continuous play has produced nearly 300 million barrels (50 million m^3) of oil and 500 BCFG (14 BCM) primarily from three large fields – Altamont, Bluebell, and Cedar Rim.

The Conventional Northern Uinta Basin play and Deep Uinta Basin Overpressured Continuous play areas are also being explored for Mesaverde Group and Mancos Shale gas reservoirs. The deeper drilling for gas could result in the discovery of new oil fields in the overlying Green River Formation.

The Conventional Southern Uinta Basin play is divided into six subplays: (a) Conventional Uteland Butte interval, (b) Conventional Castle Peak interval, (c) Conventional Travis interval, (d) Conventional Monument Butte interval, (e) Conventional Beluga interval, and (f) Conventional Duchesne interval fractured shale/marlstone.

The source rocks for the crude oil produced from the Uinta Basin plays are also found in the Green River Formation and consist of kerogen-rich shale and marlstone, which were deposited in nearshore and offshore open-lacustrine environments. Most of these oils are characterized as yellow or black wax. Production from the Deep Uinta Basin Overpressured Continuous play is dominantly yellow wax, while most of the oil production from the Conventional Northern Uinta Basin play and Conventional Southern Uinta Basin play is black wax.

Mississippian Leadville Limestone Paradox Basin Play

The Mississippian Leadville Limestone is a major oil and gas reservoir in the Utah/Colorado Paradox Basin, having produced over 53 million barrels (8.4 million m^3) of oil and 845 BCFG (23.9 billion m^3) of gas. Most Leadville production is from the Paradox fold and fault belt.

The Leadville Limestone is a shallow, open marine, carbonate-shelf deposit. Local depositional environments included shallow-marine, subtidal, supratidal, and intertidal. Solution breccia and karstified surfaces are common. Most oil and gas produced from the Leadville is found in basement-involved structural traps with closure on both anticlines and faults. The seals for the Leadville producing zones are the overlying clastic beds of the Molas Formation and evaporite beds within the Paradox Formation, both Pennsylvanian in age. Hydrocarbons in Leadville reservoirs were likely generated from source rocks in the Paradox Formation. Hydrocarbons were then expelled and subsequently migrated into traps, primarily along fault planes and fractures.

The Leadville Limestone has heterogeneous reservoir properties because of depositional facies with varying porosity and permeability, diagenetic effects, and fracturing. Identification and correlation of depositional facies in individual Leadville reservoirs is critical to

understanding their effect on production rates and paths of petroleum movement. The early diagenetic history of the Leadville sediments, including some dolomitization (finely crystalline) and leaching of skeletal grains, resulted in low-porosity and/or low-permeablility rocks. Most of the porosity and permeability associated with Leadville hydrocarbon production at Lisbon field was developed during later, deep subsurface dolomitization (coarsely crystalline replacement and saddle [hydrothermal?] dolomite) and dissolution.

Lisbon, Big Indian, Little Valley, and Lisbon Southeast fields are found on sharply folded anticlines that close against the Lisbon fault zone. Salt Wash and Big Flat fields, northwest of the Lisbon area, are found on unfaulted, east-west- and north-south-trending anticlines, respectively. The unfaulted structures probably developed from movement on deep, basement-involved faults that do not rise to the level of the Leadville. These and other faults affecting the Leadville probably reflect the reactivation of pre-existing, Precambrian-age faults during the Laramide orogeny or later.

New prospective drilling targets in the Leadville Limestone Paradox Basin play should be delineated using high-quality, two- and three-dimensional seismic data, forward modeling/visualization tools, well control, dipmeter information, and surface -geologic maps to access trap geometry. Relatively low-cost surface geochemical surveys, hydrodynamic analysis, and epifluorescence techniques may identify potential Leadville hydrocarbon migration patterns and oil-prone areas.

Pennsylvanian Paradox Formation Paradox Basin Play

The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play. The Paradox Formation has produced over 500 million barrels (80 million m^3) of sweet, paraffinic oil and 650 BCFG (18 billion m^3) from more than 70 fields. The main producing zones are referred to as the Desert Creek and Ismay. The Paradox Formation oil play area includes nearly the entire Paradox Basin. The Paradox Formation play is divided into four subplays: (1) fractured shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone.

In Pennsylvanian time, the Paradox Basin was rapidly subsiding in a subtropical arid environment with a shallow-water carbonate shelf on the south and southwest margins of the basin that locally contained carbonate buildups. In the Blanding sub-basin, Ismay-zone reservoirs are dominantly limestones composed of small, phylloid-algal buildups; locally variable, inner-shelf, skeletal calcarenites; and rare, open-marine, bryozoan mounds. Desert Creek-zone reservoirs are dominantly dolomite comprising regional, nearshore, shoreline trends with highly aligned, linear facies tracts. On the Aneth platform, Desert Creek reservoirs include shallow-shelf buildups (phylloid algal, coralline algal, and bryozoan buildups [mounds]) and calcarenites (beach, dune, and oolite banks). Here, the Desert Creek and Ismay zones are predominately limestone, with local dolomitic units.

Phylloid-algal mound lithofacies in both the Ismay and Desert Creek zones contain large phylloid-algal plates and skeletal grains that create bafflestone or bindstone fabrics. Bryozoan buildup lithofacies are represented by bindstone, bafflestone, and packstone fabrics. Calcarenite lithofacies include grainstone and packstone fabrics containing oolites, coated grains, hard peloids, bioclastic grains, shell lags, and intraclasts.

Traps in the Blanding sub-basin and Aneth platform regions include stratigraphic, stratigraphic with some structural influence, combination stratigraphic/structural, and diagenetic.

Many carbonate buildups appear to have developed on subtle anticlinal noses or structural closures. Vertical reservoir seals for the Paradox producing zones are shale, halite, and anhydrite within the formation; lateral seals are permeability barriers created by unfractured, off-mound (non-buildup) mudstone, wackestone, and anhydrite. Hydrocarbons in Paradox Formation reservoirs were generated from source rocks within the formation itself during maximum burial in the Late Cretaceous and early Tertiary. Organic-rich units, informally named the Cane Creek, Chimney Rock, Hovenweep, and Gothic shales, are composed of black, sapropelic shale and shaley dolomite.

The Paradox Formation has heterogeneous reservoir properties because of depositional lithofacies with varying porosity and permeability, carbonate buildup (mound) relief and flooding surfaces (parasequence boundaries), and diagenetic effects. The extent of these factors, and how they are combined, affect the degree to which fluid flow barriers are created. Identification and correlation of depositional lithofacies and parasequences in individual Paradox reservoirs is critical to understanding their effect on water/carbon dioxide injection programs, production rates, and paths of petroleum movement. The typical early diagenetic events occurred in the following order: (1) early marine cementation, (2) post-burial, replacement, rhombic dolomite cementation due to seepage reflux, (3) vadose and meteoric phreatic diagenesis including leaching/dissolution, neomorphism, and fresh-water cementation, (4) mixing zone dolomitization, (5) syntaxial cementation, and (6) anhydrite cementation/replacement. Post-burial diagenesis included additional syntaxial cementation, silicification, late coarse calcite spar, saddle dolomite cementation, stylolitization, additional anhydrite replacement, late dissolution (microporosity development), and bitumen plugging.

Mapping the Ismay zone lithofacies delineates very prospective reservoir trends that contain productive carbonate buildups around anhydrite-filled intra-shelf basins. Lithofacies and reservoir controls imposed by the anhydritic intra-shelf basins should be considered when selecting the optimal location and orientation of any horizontal drilling for undrained reserves. Projections of the inner shelf/tidal flat and mound trends around the intra-shelf basins identify potential exploration targets. Pervasive marine cement may be indicative of “wall” complexes of shallow-shelf carbonate buildups suggesting potential nearby carbonate buildups, particularly phylloid-algal mounds. Platform-margin calcarenites in the Desert Creek zone are located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. Lithofacies mapping indicates a relatively untested belt of calcarenite carbonate deposits south and southeast of Greater Aneth field.

Fractured-shale beds in the Pennsylvanian Paradox Formation are oil productive in the Paradox Basin fold and fault belt (northern Paradox Basin) of southwest Utah. Jointing and fractures are controlled by regional tectonics, and salt movement, dissolution, and collapse. In the fold and fault belt, the Cane Creek shale of the Paradox Formation is composed of marine carbonate, evaporite, and organic-rich shale beds. The Cane Creek is a fractured, self-sourced oil reservoir that is highly overpressured – an ideal target for horizontal drilling. Fracture data in the Cane Creek show a regional, northeast to southwest, near-vertical, open, extensional fracture system.

Outcrop Analogs for Major Reservoirs

Utah is fortunate in that it has representative outcrop analogs for each major oil play. Production-scale outcrop analogs provide an excellent view, often in three dimensions, of

reservoir petrophysics, facies characteristics, and boundaries contributing to the overall heterogeneity of reservoir rocks. Outcrop analogs can be used as a "template" for evaluation of data from conventional core, geophysical and petrophysical logs, and seismic surveys. When combined with subsurface geological and production data, outcrop analogs can improve development drilling and production strategies, reservoir-simulation models, reserve calculations, and design and implementation of secondary/tertiary oil recovery programs and other best practices used in the oil fields of Utah and vicinity.

Thrust Belt

The prolific thrust belt Jurassic Nugget/Navajo Sandstone oil reservoir was deposited in an extensive dune field that extended from Wyoming to Arizona. Outcrop analogs are found in the stratigraphically equivalent Navajo Sandstone of southern Utah. The Navajo in the Glen Canyon National Recreation Area and San Rafael Swell displays large-scale dunal cross-strata and interdunal features such as oases, wadi, and playa lithofacies. Navajo interdune lithofacies have significantly poorer reservoir characteristics than the dune lithofacies and in a reservoir represent potential barriers to flow. Identification and correlation of dune/interdune lithofacies in individual Nugget reservoirs in the thrust belt is critical to understanding their effects on production rates and paths of petroleum movement.

The best outcrop analogs for Jurassic Twin Creek Limestone reservoirs are found at Devils Slide and near the town of Peoa, Utah. Closely spaced rhombic and rectilinear fracture patterns developed on bedding planes and within dense, homogeneous non-porous (in terms of primary porosity) limestone beds of the Rich and Watton Canyon Members. The reservoir's upper contact with the basal siltstone units (where fractures are sealed) of the overlying members set up the Rich and Watton Canyon for hydrocarbon trapping and production. Thin-bedded siltstone within the Rich and Watton Canyon Members, also observed in outcrop, creates additional reservoir heterogeneity. Identification and correlation of these barriers and baffles to fluid flow, and recognition of fracture set orientations in individual Twin Creek reservoirs is critical to understanding the effects of these parameters on production rates, petroleum movement pathways, and horizontal well plans.

Uinta Basin

Outcrop analogs in the Tertiary Flagstaff Member of the Green River Formation for the Deep Uinta Basin Overpressured Continuous play are found in central Utah. The outcrops provide good examples of deposits shed off the western highlands into the western arm of Lake Uinta. It is believed that the depositional settings observed in central Utah are similar to the setting in the northern Uinta Basin where sediments were shed off the Uinta Mountains north of the basin. Many of the proximal conglomerates observed in outcrop, were deposited in water by fan deltas extending into the lake. Other exposures of medial facies include interbedded shale, sandstone, and limestone deposited in a marginal-lacustrine environment. The distal facies of the Flagstaff Limestone is composed of open-lacustrine shale and limestone. There are no outcrops of the Green River deposits shed off of the Uinta Mountains, and, therefore, no direct outcrop analog for the Deep Uinta Basin Overpressured Continuous play.

An outcrop analog for the major oil reservoirs in the Conventional Northern Uinta Basin play is exposed along Raven Ridge in the northeastern Uinta Basin; these exposures display

landward to lakeward facies transitions. Several locations offer excellent exposures of shoreline deposits that serve as reservoirs, and bay-fill deposits that provide organic-rich source rock for the play.

Outcrop analogs for the major oil reservoirs in the Green River Formation in the Conventional Southern Uinta Basin play are well exposed in Willow Creek, Indian, and Nine Mile Canyons in the south-central Uinta Basin. The Uteland Butte interval exposed in Nine Mile Canyon is a dolomitized ostracod and pellet grainstone and packstone deposited in shallow-water mudflats, pelecypod-gastropod sandy grainstone, commonly interbedded with silty claystone or carbonate mudstone deposited in shallow open-lacustrine environments, and dark-gray kerogen-rich carbonates deposited in deeper offshore environments. The Castle Peak interval is exposed in the western portion of Nine Mile Canyon as interbedded carbonate, shale, and sandstone. The primary reservoir rocks are isolated channel deposits. The secondary reservoirs in the Travis interval and the primary reservoirs in the Monument Butte and Beluga intervals are distributary-channel deposits. The Monument Butte interval typically contains amalgamated stacked channel deposits, whereas in the Travis and Beluga intervals, the distributary channels are generally isolated individual channels. The Duchesne interval represents the maximum rise and eventual waning stages of ancient Lake Uinta and is well exposed in Indian Canyon south of the town of Duchesne.

Fractures can be observed in the Green River Formation in Indian Canyon and throughout the surface exposures in the Duchesne field along the Duchesne fault zone. Any fractured outcrop in the upper and saline members can be considered a reservoir analog.

Paradox Basin

Excellent outcrops of Mississippian Leadville Limestone-equivalent rocks are found along the south flank of the Uinta Mountains, Utah (Madison Limestone), and in the Marble Canyon area of Grand Canyon National Park, Arizona (Redwall Limestone). They provide production-scale analogs displaying the facies characteristics, geometry, distribution, and the nature of boundaries which contribute to the overall heterogeneity of Leadville reservoir rocks. These formations are fine to coarse crystalline, cherty limestone with some dolomite. Limestone units commonly contain numerous caverns, sinkholes, and local zones of solution breccia and vugs. Some sections can have high heterogeneity due to development of stylolites, jointing, and fractures. Elsewhere, possible carbonate buildups, shoals and banks, and mud mounds are also found in the Madison and Redwall.

In the Paradox Basin, hydrocarbons are stratigraphically trapped in heterogeneous reservoirs within carbonate buildups (or phylloid-algal mounds) of the Pennsylvanian Paradox Formation. Carbonate buildups are exposed along the San Juan River of southeastern Utah. Reservoir-quality porosity may develop in the types of facies associated with buildups, such as troughs, detrital wedges, and fans, identified from these outcrops. If these facies are in communication with mound-reservoir facies in actual reservoirs, they could serve as conduits facilitating sweep efficiency in secondary/tertiary recovery projects. However, the relatively small size and the abundance of intermound troughs over short distances, as observed along the river, suggests caution should be used when correlating these facies between development wells. Facies that appear correlative and connected from one well to another may actually be separated by low-permeability facies which inhibit flow and decrease production potential. These outcrop analogs also demonstrate that there are various targets and risks when considering horizontal

drilling in the Paradox Basin. Before selecting the optimal location, orientation, and type of horizontal well, the distribution, both laterally and vertically, of phylloid-algal mounds and other associated facies must be carefully evaluated.

Land Classification

This land classification summary was prepared using a format tool called hypertext markup language (HTML). HTML is used to provide the reader with internet access to the Web sites and documents discussed or listed in this report.

The objectives of this summary are to compile maps and document the major land and mineral ownership types in each of the four oil-producing provinces Utah and where they extend into Arizona, Colorado, and Wyoming; to identify the federal, state, county, and other private and non-profit agencies involved in the environmental analysis, leasing, and development of oil and gas resources; and to provide an overview and listing of pertinent data, documents, and research tools that might be helpful in understanding the oil and gas industry, primarily in Utah, but also in parts of Arizona, Colorado, and Wyoming. Surface ownership data for each state were acquired primarily in GIS format from resources available on the Internet.

The four oil-producing provinces in this study (Utah/Wyoming thrust belt, Central Utah thrust belt – Hingeline, Uinta Basin, and Paradox Basin) encompass nearly 15.1 million acres (6.1 million ha) and include almost all of the potential oil- and gas-bearing land in Utah, as well as lands in adjacent parts of Arizona, Colorado, and Wyoming. Surface and mineral ownership is divided primarily among federal, state, private, and Native American interests. Nearly 8.6 million acres or 57% of the land is federally owned and administered by the U.S. Bureau of Land Management (BLM) and several other federal agencies including the U.S. Forest Service (USFS), National Park Service, U.S. Fish and Wildlife Service, Department of Defense (DOD), and U.S. Bureau of Reclamation. BLM or public lands, constitute the largest ownership entity in the four oil-producing provinces with 42.6% of the total acreage. Other major land designations include state lands, private or fee lands, and Native American Reservation lands.

State lands, including state parks and wildlife reserves, comprise 8.2% of the total land in the four provinces and include 1.25 million acres (510,000 ha). Each state has its own agency or agencies that administer its respective lands, and commissions or divisions that administer oil and gas development. There are no state-owned lands in the Arizona part of the Paradox Basin province. For Colorado, state agencies involved in oil and gas development include the Colorado State Land Board and the Colorado Oil and Gas Conservation Commission. In Utah, state lands are administered by either the Utah Division of Forestry, Fire, and State Lands or the Utah School and Institutional Trust Lands Administration. Oil and gas development in Utah is administered by the Utah Division of Oil, Gas and Mining. In Wyoming, state lands are administered by the Wyoming Office of State Lands and oil and gas development is administered by the Wyoming Oil and Gas Conservation Commission. Web site and contact information for all of these entities is contained in the body of this report and in the appendices.

Privately owned lands or fee lands comprise 23.1% of the oil provinces and encompass nearly 3.5 million acres (1.4 million ha). These lands are owned by individuals, corporate or legal entities, or a sovereignty in the case of an Indian tribe. In each case, oil and gas rights or leases are negotiated with the mineral-estate owner(s) and surface access, if required, is negotiated with the surface owner. Where an Indian tribe owns the mineral estate, leases are usually negotiated with the tribal business committee. Numerous royalty owners associations

have been formed to pool information and lease management among groups of individual royalty owners. The most prominent of these non-profit organizations is the National Association of Royalty Owners.

Native American Reservation lands comprise 11.5% of the oil provinces and include 1.7 million acres (690,000 ha) of land within an established Indian Reservation. These lands are held in trust by the U.S. government and administered by the Bureau of Indian Affairs (BIA). Also, within some reservations, tribal members own land individually; these are referred to as allotted lands. Because of the complexity of Indian land ownership, only designated reservations lands are shown on the maps. Native American Reservation lands in the Uinta Basin province are within the Uinta & Ouray Indian Reservation, which is headquartered in Fort Duchesne, Utah. Native American Reservation lands in the Paradox Basin province are Navajo Nation lands whose offices are in Window Rock, Arizona, and Ute Mountain Indian Reservation lands whose tribal offices are in Towaoc, Colorado. Native American Reservation lands in the Central Utah thrust belt-Hingeline province are Paiute Indian Reservation lands whose tribal office is in the town of Joseph, Utah.

In an attempt to make the administrative effort more responsive to individual tribal interests, the BIA has developed a set of rules regarding Tribal Energy Resource Agreements, which offer federally recognized tribes a new alternative for overseeing and managing energy and mineral resource development on their lands. All of the rules and regulations pertaining to oil and gas development on BIA-administered tribal lands are posted on the BIA Web site.

Mineral ownership patterns vary among the oil provinces, and dominant ownership is somewhat different in each province although federal ownership is dominant overall. Federal ownership is multifaceted in that while the mineral estate is managed primarily by the BLM, the overlying surface estate might be managed by other federal agencies. The surface estate may also be privately owned, creating a split estate, which is common in the Western U.S. The BLM, in consultation with numerous oil and gas, ranching, and other organizations, has established a set of guidelines for dealing with split mineral estate issues.

All federal agencies are governed by laws, which provide mandatory management direction to the agencies; regulations, which are promulgated by each agency and are subject to public review; and policies, which further complement the laws and regulations. Policies are internal documents that have no external review requirement.

Two key laws influence BLM's planning efforts: the Federal Land Policy and Management Act of 1976 (FLPMA), and the National Environmental Policy Act of 1969 (NEPA). The BLM National Planning Handbook outlines a process that meets the requirements of both NEPA and FLPMA for the development of planning decisions. An interdisciplinary team established to work on planning projects ensures that the BLM is complying with other laws, regulations, and policies associated with particular resources and uses of the public lands. Together, NEPA and FLPMA, as well as the associated regulations, form the basis for BLM's planning process. The BLM's planning handbook is a BLM policy that encompasses the requirements of NEPA and FLPMA laws and regulations.

BLM lands are managed on a national level by federal regulations, on a state level by the statewide administration of federal regulations and state policies, and on a local level by field offices, which are responsible for the day-to-day management and resource planning for federal lands within their areas of responsibility. Public lands are available for oil and gas leasing only after they have been evaluated through the BLM's multiple-use planning process.

The BLM issues two types of leases for oil and gas exploration and development on lands owned or controlled by the federal government - competitive and noncompetitive.
The Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and have not received a bid.

The maximum competitive lease size is 2560 acres (1036 ha) in the lower 48 States and 5760 (2331 ha) acres in Alaska. The maximum noncompetitive lease size in all States is 10,240 acres (4144 ha).

Since passage of the Energy Policy Act of 1992, both competitive and noncompetitive leases are issued for a 10-year period. Both types of leases continue for as long thereafter as oil or gas is produced in paying quantities.

Oral auctions of all oil and gas leases are conducted by most BLM state offices not less than quarterly when parcels are available. A Notice of Competitive Lease Sale, which lists lease parcels to be offered at auction, is published by each BLM state office at least 45 days before an auction is held. Lease stipulations applicable to each parcel are specified in the Sale Notice. Lands included in a sale are identified by informal expressions of interest from the public, or by the BLM for management reasons, or lands included in offers filed for noncompetitive leases. All auctions are conducted with oral bidding. Bidders must attend the auction to obtain a competitive lease or provide for someone to represent them.

In general, leases are granted on the condition that the lessee will have to obtain BLM approval before conducting any surface-disturbing activities. Oil and gas lease-sale notices and results are posted on each BLM state office's Web site as well as other oil and gas related federal agency Web sites.

Following issuance of a lease and before exploratory drilling can begin, the leaseholder must submit an Application for Permit to Drill (APD). This application process is very rigorous and comprehensive. The application of Best Management Practices in oil and gas leasing is defined in the new 2007 *Gold Book* (4^{th} edition), a joint effort of the BLM and FS.

Oil and gas lease maps and surface and mineral land status maps can be created through the BLM's National Integrated Land System (NILS) <http://www.blm.gov/wo/st/en/prog/more/nils.html>. NILS is a joint project between the BLM and the FS in partnership with the states, counties, and private industry to provide business solutions for the management of cadastral records and land parcel information in a GIS environment.

Land use planning emphasizes a collaborative environment in which local, state, and tribal governments, the public, user groups, and industry work with the BLM to identify appropriate multiple uses of the public lands. The land-use planning process allows for extensive public involvement and provides a blueprint of how the public land will be managed. Documentation for each Land Use Plan (LUP) and Resource Management Plan (RMP) is available on each BLM state office Web site and local field office Web sites.

In 2008, several BLM districts in Utah, Colorado, and Wyoming are in the process of creating new RMPs. Some of Utah's RMPs that are under revision have been identified by the BLM as 'Time Sensitive Resource Management Plans' to timely address energy resources studied under the Energy Policy and Conservation Act (EPCA). In Utah, these include the Price and Vernal RMPs, which are in the Paradox Basin and Uinta Basin oil provinces respectively. Under EPCA, signed into law by President Clinton in 2000, federal agencies were tasked with

developing a national inventory of all oil and gas resources and reserves beneath federal lands. This data is now being incorporated into RMPs to plan for multiple uses on the public lands, and specifically plan for the responsible development of energy resources in these areas. Other new resource planning efforts for the major oil provinces include: Utah/Wyoming thrust belt — Kemmerer RMP, Central Utah thrust belt—Hingeline — Richfield RMP, Uinta Basin — White River RMP, Paradox Basin — Kanab RMP and Moab RMP, Monticello RMP, and Richfield RMP.

In addition to BLM public lands, federal lands designated as Wilderness Areas by Congress are specifically withdrawn from any type of development. Only one Wilderness Area is located within the four oil provinces. However, numerous Wilderness Study Area and Instant Study Area lands in the Uinta Basin and Paradox Basin provinces, totaling 1,044,468 acres (422,690 ha), have been identified and mapped in each of the oil provinces. These lands are managed by the BLM under special interim rules until they are either designated as Wilderness or released. A history of the debate over Wilderness and links to documentation for each WSA and ISA are provided in the body of this report.

Land ownership summaries and maps for each oil province are provided in the text, tables, and maps included in this report. Web site and contact information for all of the federal, state, and county agencies and offices that are involved in ownership, leasing, and oil and gas development are listed in the appendices.

Best Practices

Jurassic Nugget/Navajo Sandstone and Twin Creek Limestone Thrust Belt Plays

Horizontal drilling in the Utah thrust belt fields targets the heterogeneous Twin Creek Limestone and Nugget Sandstone reservoirs. Drilling techniques include new wells and horizontal, often multiple, laterals from existing vertical wells. Multiple laterals are required where two separate, geologically distinct zones are present. Fractures and lithologic variations create potential undrained compartments ideally suited for horizontal drilling, particularly in the Watton Canyon Member of the Twin Creek. Horizontal wells should generally be drilled perpendicular to the dominant orientation of open fractures, and above and parallel to the low-proved oil or oil/water contacts.

Horizontal drilling programs at Pineview, Lodgepole, and Elkhorn Ridge fields in the Utah thrust belt successfully extended the productive life of those fields. Horizontal drilling was probably uneconomical at Pineview, marginally economic at Lodgepole, and economically successful at Elkhorn Ridge. All three fields were at an advanced stage of depletion when the horizontal drilling began and in structurally complex settings making it difficult to avoid formation water. An enhanced-oil-recovery waterflood project in the Elkhorn Ridge field also utilizes horizontal wells.

Reservoir compositional simulation studies were conducted on Painter Reservoir field. Ultimate recovery was determined for a tertiary, miscible nitrogen-injection program. In this process, nitrogen and hydrocarbon gas are over-injected into the reservoir to raise the reservoir pressure to miscible conditions producing an excellent sweep of oil over a 60-year period. The simulation indicated that when this program is supplemented with water injection, the ultimate recovery could be 113 million barrels (18 million m^3) of oil (a 68% recovery factor).

Condensate production is common in Absaroka thrust - Mesozoic-cored deep structures. In retrograde condensate reservoirs, the fluid changes from a single-phase rich gas to a two-phase gas and liquid mixture when the pressure drops below the dew-point pressure. Without pressure maintenance, the retrograde condensate remains in the reservoir and wells are less productive. Maximizing liquid recovery requires a thorough understanding of reservoir geometry, fluid distribution, and phase behavior. The Nugget Sandstone in Anschutz Ranch East field on the Utah/Wyoming border is a major retrograde condensate reservoir where pressure maintenance operations have successfully maximized recovery. The full reservoir pressure maintenance program required initial injection of a buffer gas (a mixture of 35% nitrogen and 65% wet gas) equal in volume to 10% of the hydrocarbon pore volume, followed by the injection of pure nitrogen. Cumulative production through 2007, from Anschutz Ranch East field is over 129 million bbls (20.5 million m^3) of condensate.

Development wells drilled to the Jurassic Navajo Sandstone in Covenant field, central Utah thrust belt – Hingeline, are perforated in selected intervals with four jet shots per foot. The perforations are broken down using small, 7.5% hydrochloric acid treatments with additives, primarily to clean perforations of clays from drilling muds. Electrical submersible pumps are installed to artificially lift fluids. The well spacing is about 40 acres (16-ha) within the Covenant unit. Wells are drilled from three pads and deviated to avoid rugged topography. Secondary and tertiary recovery programs may include nitrogen injection and/or a carbon dioxide flood.

Uinta Basin Plays

Conventional Northern Uinta and Deep Uinta Basin Overpressured Continuous plays: In the Conventional Northern Uinta and Deep Uinta Basin Overpressured Continuous plays, current drilling and production practices in the Altamont-Bluebell-Cedar Rim field trend will leave a significant amount of oil unproduced. The current (November 2008) practice of drilling two wells per section will leave a significant volume of hydrocarbons behind. Accurately identifying which beds actually contribute to the production and the role that naturally occurring fractures play in the reservoir remains a major problem for trend development. We recommend that operators in the Bluebell field use geophysical and imaging logs as the primary tool for selecting perforation intervals in new wells, not drilling shows as is commonly done. This should result in a reduction of the number of beds perforated, and more effective treatment. In recompletion of existing wells, cased-hole logs can help identify additional beds to be perforated, and if necessary, identify beds that can be treated individually.

A portion of the untapped resource potential in the Conventional Northern Uinta Basin play and Deep Uinta Basin Overpressured Continuous play may be exploited through recompletions of the current wells. Existing well completions typically consist of perforations in 40 or more beds in a 1500-foot (450 m) or more, vertical section. As a result, many of the beds never received adequate stimulation. We recommend using cased-hole logs to identify by-passed oil and selectively stimulate individual beds to recover significant amounts of additional oil.

Staging acid treatments over smaller (500-foot [150 m]) intervals and greatly increasing the amount of diversion material used has been shown to be an effective completion technique. Particularly in newer wells, perforating fewer beds and treating shorter gross intervals can result in better completions. Older wells that have been recompleted many times eventually become uneconomical to retreat. In these wells only a minor incremental increase in the oil production

rate occurs after treatment because so much of the acid is going into beds that are depleted of oil. A bed-scale completion technique could be effective in older wells nearing depletion where a larger staged completion is no longer economical. Therefore, in older wells we recommend that treatment of a few individual beds be attempted using a dual packer tool. This way, only the few beds with remaining oil potential are acidized, reducing the size of the treatment needed, and providing more effective stimulation of the beds with remaining potential.

Hydrochloric acid has been the recommended treating fluid for most of the life of the field, although many operators now use a proppant stimulation. The tubing should be pickled and reversed out just prior to doing the main acid treatment. Good diversion is also critical to treating the entire interval and a high enough pump rate must be maintained to carry the diverting agent. Higher pumping rates and well-head-treating pressures result in more effective treatments. The higher pressures and pump rates could be indications of good diversion taking place, which allows more of the treatment fluids to enter more of the formation. A pumping rate between 8 and 12 bbls per minute (1.3-1.9 m^3/min) with proper gelling agents in the fluid will divert the fluid to the perforated intervals, and maintain a reasonable well-head-treatment pressure.

Even successful acid treatments, in most cases, do not maintain adequate linear flow over time, indicating understimulation of the producing formation. Many years ago proppant treatments used only a small volume of propping agent. The ability to do high-rate proppant fracs over large intervals has been proven in other fields in the Uinta Basin and is becoming more common in the Altamont-Bluebell-Cedar Rim field trend. Many older wells may not be suitable for this treatment, but newer wells should be considered candidates for high-rate proppant fracture treatments.

The dual-burst, thermal-decay time and dipole-shear anisotropy logs are reliable tools for evaluating remaining hydrocarbon potential and fracture density in a cased-hole well that has been producing oil for many years. These tools can be used to identify potentially productive beds that are not perforated in older wells, to eliminate the acidizing of previously perforated beds that have little to no potential, and to determine if the acid fracture treatment is hydraulically fracturing the formation.

Currently, the high-paraffin oil produced is stored on location in insulated tanks and the production facilities have a heat treater that keeps the oil above the pour-point temperature. Screen cones are placed on the heat treater stacks to prevent birds from getting into the stacks. Three types of pumps are commonly used in the Altamont-Bluebell-Cedar Rim field trend: (1) the standard pump jack, both center and rear gearbox, (2) the submersible pump and, (3) the rotary flex pump. Water production is a significant part of the operating costs, but a water gathering system using water-injection wells enables disposal of 90% of the produced water and represents a significant cost savings. Fluids from testing and recompletion operations now go into metal pit tanks prior to disposal.

Secondary and tertiary recovery methods have not been attempted in the Deep Uinta Basin Overpressured Continuous play area. Fractures are the dominant reservoir property and could cause early breakthrough of any injected fluid or gas. Secondary and tertiary recovery methods generally require a high density of wells to be effective. The Deep Uinta Basin Overpressured Continuous play area has been developed with only two wells per section and in many areas at least one of those wells has already been plugged and abandoned. As a result, any secondary or tertiary recovery method would require a significant amount of additional deep drilling.

In the eastern Uinta Basin, production and ultimate recovery from the waterflood units in the Red Wash-Wonsits Valley producing trend are enhanced by the following completion and reservoir management practices: conversion of all geophysical well logs into digital form allowing extensive mapping, correlating, and construction of cross sections; running generally much smaller fracture treatments than in the past to ensure that the induced fractures do not extend vertically out of the intended zone; fingerprinting oil samples from each producing zone to determine the percentage each zone contributes to the overall production of the well; running spinner surveys biannually to determine which zones are producing water; mapping producing zones including oil and water production to determine the advance of the waterfront for each zone and identify areas that may be by-passed by the flood; and drilling on 80-acre (32-ha) spacing to prevent rapid water breakthrough. The estimated secondary recovery using a waterflood program in Red Wash-Wonsits Valley fields is 79.4 million barrels of oil (12.6 million m^3).

Conventional Southern Uinta Basin play: In the Conventional Southern Uinta Basin play, production and ultimate recovery from the waterflood units in the greater Monument Butte field area are enhanced by the following drilling, development, and production practices: (1) using operator-owned drilling rigs to ensure availability and lower costs compared with contracting; (2) using operator-owned frac holding tanks to reduce the cost of the fracture treatments; (3) selecting sandstone beds with more than 8% neutron porosity for perforation and stimulate each bed with separate fracture treatments beginning with the lowermost perforated bed; (4) using artificial lift for wells on primary production; (5) converting wells relatively soon to secondary waterflooding to maintain reservoir pressure above the bubble point to maximize oil recovery; (6) developing waterflood units using an alternating injector – producer pattern on 40-acre (16-ha) spacing; (7) recompleting producing wells by perforating all beds that are productive in the waterflood unit; (8) hiring people who can work closely with the regulatory agencies involved; and (9) maintaining several drilling options so if environmental issues delay some parts, there are other drilling activities that can be pursued.

Paradox Basin Plays

Mississippian Leadville Limestone play: Productive wells in fields productive in the Leadville Limestone are drilled with air or fresh-water mud to the top of the Pennsylvanian Paradox Formation salt, after which a natural brine or salt-based mud is typically used to total depth. The wells are usually completed by perforating with four shots per foot, in Leadville high-quality porosity zones. The completion treatment includes stimulation of perforated intervals with 15% hydrochloric acid.

A thick hydrocarbon column at Lisbon field contains a gas cap and oil ring. Associated, lean, processed, sour gas was reinjected into the gas cap to maintain reservoir pressure and maximize the oil recovery. Gas-sweetening, nitrogen-injection, and helium-recovery facilities were installed in 1992, and in 1993 the operator began gas cap blowdown and sale of residue gas.

Horizontal drilling technology was not readily available when Lisbon field and other Leadville fields were discovered and developed. If horizontal technology had been available, Leadville fields could have been developed with fewer wells (especially in environmentally sensitive areas), and would have resulted in a greater ultimate oil recovery. Lithologic variations

due to facies changes, diagenetically increased porosity zones due to dolomitzation, and fractures create potential undrained compartments ideally suited for horizontal drilling in the Leadville-producing fields. Drilling techniques should include new wells, and horizontal, often multiple and stacked, laterals from existing vertical wells. Finally, a decision about drilling horizontally in Leadville fields should also be based on the reservoir depth, regulatory requirements for spacing, type of application, and surface location to avoid topographic features.

Pennsylvanian Paradox Formation play: The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play. The Paradox Formation play is divided into four subplays: (1) fractured Cane Creek shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone.

Drilling in the Paradox Basin may be vertical, deviated, or horizontal. Wells are drilled with a fresh water mud to the top of the Paradox Formation salt, after which a natural brine, salt-based mud, or gel-based mud is typically used to total depth. Severe water flows can occur in both the Permian DeChelly and Jurassic Navajo Sandstones. Wells are drilled to total depth either through the Ismay zone and into the Gothic shale, or through the Desert Creek zone and into either the Chimney Rock shale or salt at the top of the Akah zone, and are evaluated with standard suites of geophysical logs. Vertical wells are completed with matrix-acid stimulations. Fracturing is occasionally performed in low-permeability reservoir units.

In the eastern Paradox Basin, Colorado, production and ultimate recovery from the McClean field area is enhanced by the following drilling, development, and production practices: increasing the mud weight to 12.5 pounds (5.7 kg) during drilling operations before penetrating the overpressured Desert Creek zone; centralizing treatment facilities; and mixing produced water from pumping oil wells with non-reservoir water and injecting the mixture into the reservoir downdip to reduce salt precipitation, dispose of produced water, and maintain reservoir pressure creating a low-cost waterflood.

Three significant late-term development practices are, or could be, employed in the recent development of fields in the Paradox Formation play to enhance the ultimate recovery of oil: (1) horizontal drilling, (2) waterfloods, and (3) CO_2 floods. To plan horizontal wells, it is critical to identify and correlate depositional lithofacies, parasequences, and fracture trends in individual Paradox reservoirs in order to understand their effects on water/carbon dioxide injection programs, production rates, and paths of petroleum movement.

Horizontal drilling techniques include new wells and horizontal, often multiple, laterals from existing vertical wells. Multiple laterals are recommended where two separate, geologically distinct reservoir zones are present. Strategies for horizontal drilling involve drilling stacked, parallel horizontal laterals. Depositional lithofacies are targeted in both the Ismay and Desert Creek zones where, for example, multiple buildups can be penetrated with two opposed sets of stacked, parallel horizontal laterals. Much of the elongate, brecciated, beach-mound depositional lithofacies in the Desert Creek zone could be penetrated by opposed sets of stacked, parallel, horizontal laterals. Similarly, a second horizontal drilling strategy involves penetrating multiple zones of diagenetically enhanced reservoir intervals in these mound buildups. Horizontal drilling also increases the probability of encountering near-vertical fractures needed for economic oil production in the fractured shale subplay and has resulted in a high success rate.

Waterfloods are the most common type of secondary oil recovery technique in the Paradox Basin. Depth, drive mechanisms, and water, oil, and gas saturations are major factors to determine candidate reservoirs for waterflood programs. The higher the initial gas-oil ratio

(GOR), the poorer the oil recovery from waterflooding. Generally, the initial GOR for Paradox Formation reservoirs is less than 1000 cubic feet/barrel. Low-pressure, low-GOR reservoirs often have waterflood to primary oil recovery ratios in excess of 2:1. Very few Paradox reservoirs have higher than normal pressure, with most in the 1600 to 2200 pounds per square inch (11,000-15,000 kPa) range. Water-drive reservoirs are usually not good candidates for waterflooding. The drive mechanisms for most Paradox reservoirs are solution gas, gas expansion, fluid expansion, or pressure depletion. The waterflood program in the Aneth unit of Greater Aneth field now uses horizontal laterals in a line-drive injection pattern which improves both areal and vertical sweep efficiencies over vertical wells. Production and injection laterals are drilled into the Desert Creek porosity zones to sweep oil that vertical wells could not reach.

Carbon dioxide (CO_2) flooding is relatively low risk, significantly increases oil recovery, and extends the life of a field by 20 to 30 years. Ultimate oil recovery may increase by over 40% with CO_2 flooding (8 to 16% due to CO_2 flooding alone). Carbon dioxide miscibility needs to be attainable over a major portion of the reservoir; that includes widespread good injectivity and reservoir connectivity. Therefore understanding reservoir lithofacies, heterogeneity, and petrophysical properties are critical in planning CO_2 flooding programs. The reservoir should be deeper than 2500 feet (760 m) and the American Petroleum Institute (API) gravity of the oil greater than 25º. The depth to the Ismay and Desert Creek zones generally ranges from 5320 to 5920 feet (1620-1800 m); the API gravity of Paradox Formation oils ranges from 38º to 53º. The maximum viscosity must be 10 to 12 centipoise (cP); the viscosity of Greater Aneth oil is 0.54 cP. Prospective CO_2 flooding candidates should first perform well during waterflood programs. If production water cut reaches 98%, especially during waterfloods, operators likely lose the ability to borrow capital against future production and CO_2 flooding becomes uneconomic. It is also important to recognize that CO_2 prices fluctuate in response to crude oil prices.

Obviously, a reliable source of CO_2 must be available for long-term CO_2 flooding programs. The Devonian Ouray Formation and Mississippian Leadville Limestone at McElmo Dome field on the eastern edge of the Paradox Basin in southwest Colorado supply CO_2 to Greater Aneth field. With only the one pipeline in the Paradox Basin, alternate sources of CO_2 may have to be obtained by drilling. Several in-field exploratory wells have tested gas containing CO_2 concentrations of 80% or higher from the Ouray and Leadville. Another potential source of CO_2 is emissions from coal-fired power plants.

Carbon dioxide flooding began in the McElmo Creek unit of Greater Aneth in 1985. The production response was between one and two years through a water-alternating-gas program. Oil production increased from 5500 barrels of oil per day (BOPD) to 6500 BOPD (880-1030 m^3/d), peaking after a ten-year period. Incremental recovery from CO_2 flooding is estimated at 33 million barrels of oil (5.3 million m^3) or an incremental recovery efficiency increase of 9.3%. Horizontal wells in the Aneth unit may also be used for CO_2 flooding; however, horizontal laterals need to be oriented parallel to fault/fracture zones to prevent rapid breakthrough.

Reservoir three-dimensional (3-D) modeling and simulation should be major components in designing waterflooding and CO_2 flood programs for Paradox Formation. High-speed, state-of-the-art computer capability requires accurate and detailed geologic characterization and reservoir engineering data to predict waterflood and CO_2 flood performance. Numerical simulations illustrate the significant impacts of parasequence boundaries and reservoir heterogeneity created by shale, anhydrite, and low-permeability carbonate rocks common in the Paradox Formation. Results of 3-D modeling and numerical simulation can (1) estimate oil recovery and water cut, (2) determine the spacing and pattern of vertical wells, and (3) predict the viability of horizontal wells in waterflood and CO_2 flood programs.

INTRODUCTION AND OVERVIEWS OF MAJOR OIL-PRODUCING PROVINCES

CHAPTER 1
INTRODUCTION

Thomas C. Chidsey, Jr., and Richard G. Allis,
Utah Geological Survey

Overview

Utah oil fields have produced over 1.34 billion barrels (bbls) (211 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The 13.7 million bbls (2.2 million m^3) of production in 2002 was the lowest level in over 40 years. However, in late 2005 oil production increased (figure 1-1), due, in part, to the discovery of Covenant field in the central Utah Navajo Sandstone thrust belt ("Hingeline") play, and to increased development drilling in the central Uinta Basin, reversing the decline that began in the mid-1980s (Utah Division of Oil, Gas and Mining, 2008). Despite over 40 years of production at rates that have varied by a factor of three, proven oil reserves during this time have remained above 200 million bbl (32 million m^3), indicating significant oil remains to be produced. Currently, proven reserves are relatively high, at 334 million bbls (53.1 million m^3) (Energy Information Administration, 2007). With higher oil prices now prevailing, secondary and tertiary recovery techniques should boost future production rates and ultimate recovery from known fields.

While Utah still contains large areas that are virtually unexplored, there is also significant potential for increased recovery from existing fields by employing improved reservoir characterization and the latest drilling, completion, and secondary/tertiary recovery technologies. New exploratory targets may be identified from three-dimensional (3D) seismic surveys. Development of potential prospects is within the economic and technical capabilities of both major and independent operators.

The primary goal of this report is to increase recoverable oil reserves from existing field reservoirs and new discoveries by providing play portfolios for the major oil-producing provinces (thrust belt, Uinta Basin, and Paradox Basin) in Utah and adjacent areas in Wyoming, Colorado, and Arizona (figures 1-2 and 1-3). The U.S. Geological Survey defines "a play" as a set of known or postulated oil accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration pathway, timing, trapping mechanism, hydrocarbon type. This definition was the basis for the plays determined in the project. Analysis of the plays required evaluation of regional cross sections, correlation and mapping of reservoir facies, identification of wells with hydrocarbon "shows," use of geologic and engineering characteristics of each reservoir, and gathering field and production data from each reservoir. We also used current technology, primarily data from well logs, sample descriptions, tests, well completions, cores, publications, and outcrops.

The play portfolios include the following descriptions: (1) tectonic setting; (2) reservoir stratigraphy, thickness, and lithology; (3) type of traps; (4) seals; (5) petrophysical properties; (6) diagenetic analysis; (7) oil and gas characteristics; (8) source rocks including timing, generation, and migration of oil; (9) exploration and production history; (10) case-study field evaluations; (11) summaries of the state-of-the-art current and potential best drilling, completion, and production practices, and potential for new secondary/tertiary enhanced oil recovery; (12) descriptions of reservoir outcrop analogs for each play; (13) exploration potential and trends; and

(14) maps of the major oil plays and subplays. Also included are analyses of land-use constraints on development, such as wilderness or roadless areas and national parks within oil plays.

Exploration History

Oil and gas drilling has fluctuated greatly due to discoveries, oil and gas price trends, and changing exploration targets (figure 1-4) over Utah's exploration history extending back over 100 years. In 1891, natural gas was accidentally discovered at a depth of 1000 feet in Farmington Bay on the eastern shore of Great Salt Lake during the drilling of a water well. Between 1895 and 1896, gas from several wells near this location was transported to Salt Lake City in a wooden pipe, marking Utah's first use of local oil or gas. During the early 1900s, the first drilling targets were based on naturally occurring oil seeps at Rozel Point (northern Great Salt Lake), Mexican Hat (near Monument Valley, southeastern Utah), and near the town of Virgin (near Zion National Park) (figures 1-5 through 1-7). Surface anticlines were also the sites of early exploration (figures 1-8 and 1-9). Although oil shows were also found at several other eastern Utah locations in later decades, it was not until 1948 that Utah's first large-scale commercial oil well, Ashley Valley No. 1, was drilled near the town Vernal along the northeast boundary of the Uinta Basin. By 1960, Utah was the 10th largest oil-producing state in the country, and it has remained in the top 15 since then.

During the boom period of the early 1980s, activity peaked at over 500 wells drilled per year. After slowing in the 1990s, Utah has entered another boom period rivaling the early 1980s. In 2007, the Utah Division of Oil, Gas and Mining issued 1553 drilling permits and a record 1110 wells were spudded (Utah Division of Oil, Gas and Mining, 2008a, 2008b). This increase in activity has been spurred by high prices for both oil and natural gas, and perceptions that Utah is highly prospective and under-explored. The success rate of exploration drilling for both oil and gas has also improved, with very few dry holes being reported compared to the 1980s drilling boom.

Horizontal drilling technology, more elaborate completion techniques, and secondary and tertiary recovery techniques should collectively result in a continued boost in statewide production rates and ultimate recovery from both known fields and new discoveries. Sustained high petroleum prices are providing the economic climate needed to entice more high-risk exploration investments (more wildcats), resulting in new discoveries. In 2008, there are over 6000 producing oil and gas wells. There is also resurgence in interest in Utah's substantial oil shale and tar sand resources, which received brief attention during the 1970s oil supply crisis.

Utah and Vicinity Oil and Gas Fields and Pipelines Maps

Oil and Gas Fields

As part of determining the major oil plays in Utah, a new oil and gas fields map was produced (Chidsey and others, 2005). There are over 170 oil and gas fields in Utah, most located in three major oil-producing provinces but others are isolated accumulations with unique geologic attributes scattered throughout the state. Prior to the new map, oil and gas fields were last mapped as part of an energy resource map for Utah, which also included coal, uranium, tar sands, oil shale, geothermal resources, and other energy information (Utah Geological and

Mineral Survey, 1983). There have been over 80 new oil and gas discoveries and significant field extensions over the past twenty-five years. The new map includes: (1) productive limits of active, shut-in, and abandoned fields, (2) predominant production type such as oil, conventional hydrocarbon gas, coalbed methane, or carbon dioxide (CO_2), (3) geologic age(s) and formation name(s) of the field reservoir(s), (4) the number of active wells and cumulative oil, gas, and water production, (5) official field boundaries as defined by the Utah Division of Oil, Gas and Mining (DOGM), the state's oil and gas regulatory agency, (6) major structural basins and uplifts, (7) wilderness areas, national parks or monuments, Indian reservations, and (8) Precambrian and igneous outcrops. This map is available in hard copy and digital format (portable document format [.pdf]).

To create the new oil and gas field map, DOGM provided base maps with all well locations posted (over 9000 abandoned, producing, or injection wells). The productive limits of the fields were delineated using these well locations taking into account regional structural and stratigraphic trends. Production and completion records, published field studies and summaries, and the 1983 energy resource map, were checked to determine the current status, predominant production, and producing reservoirs. ArcView® shape files for wilderness areas, national parks, and Indian reservations were provided by the Utah School and Institutional Trust Lands Administration. Precambrian and igneous outcrop locations were generated from a digital geological map of Utah (Hintze and others, 2000). Boundaries of basins and uplifts were modified from various geologic and reservoir maps of Utah (Chidsey and others, 1993a, 1993b).

Plate 1 is the oil and gas fields map of Utah merged with thrust belt fields of Wyoming (DeBruin, 2002) and Paradox Basin fields of Colorado (Wray and others, 2002) and Arizona.

Pipelines

Oil from many of Utah's oil fields, particularly Uinta Basin fields, is trucked to refineries in Salt Lake City. However, oil pipelines do service a large number of fields both in Utah and surrounding states. There are also numerous natural gas pipelines, one pipeline capable of carrying hydrogen sulfide (H_2S) in the thrust belt, and two pipelines that deliver carbon dioxide (CO_2) for secondary/tertiary oil recovery projects in Utah's Greater Aneth field (figure 1-2) in the Paradox Basin and Rangely field in western Colorado's Piceance Basin (plate 1). Prior to the new map, the oil and gas pipeline map for Utah was last published in 1994 (Anderson and Chidsey, 1994). Like the oil and gas fields, there have been numerous new pipelines constructed in Utah over this time period. The ownership of Utah pipelines has changed considerably in the last 10 years. As part of describing the major oil plays in Utah, oil and gas pipelines were updated with the oil and gas fields map. The new map includes: (1) all pipelines with diameters greater than 6 inches, (2) the identification of what the pipeline carries, such as oil, gas, hydrocarbon products, H_2S, or CO_2, and (3) the current operator.

To create the new pipeline portion of the map, the locations of transmission, distribution, and gathering pipelines were compiled and digitized from a variety of sources. These sources included donated maps (some digital) and files from field operators, utilities, and transmission and refining companies, as well as published maps.

Plate 1 also includes Utah pipelines and pipelines from the Wyoming thrust belt (DeBruin, 2002) and Paradox Basin of Colorado (Wray and others, 2002) and Arizona.

Project Benefits

The overall goal of this report is enhanced petroleum production in the Rocky Mountain region. Specific benefits expected to result from this report include the following:

(1) improved reservoir characterization to prevent premature abandonment of numerous small fields in the Paradox and Uinta Basins,

(2) identification of the type of untapped compartments created by reservoir heterogeneity (for example, diagenesis and abrupt facies changes) to increase recoverable reserves,

(3) identification of the latest drilling, completion, and secondary/tertiary techniques to increase deliverability,

(4) identification of reservoir trends to stimulate field extension and exploration drilling in undeveloped parts of producing fairways,

(5) identification of technology used in other basins or producing trends with similar types of reservoirs that might improve production in Utah,

(6) identification of optimal well spacing/location to reduce the number of wells needed to successfully drain a reservoir, thus reducing development costs and risk, and allowing more productive use of limited energy investment dollars, and

(7) communication of the above findings to encourage new development and exploration efforts, and increase petroleum supply and royalty income for the federal, state, local, Native American, and fee owners.

The Utah play portfolios in this report provide a comprehensive geologic, engineering, and geographic reference to help petroleum companies plan exploration, land-acquisition strategies, and field development. These portfolios can also help pipeline companies plan future facilities and pipelines. Other potential users of the portfolios include petroleum engineers, petroleum land specialists, landowners, bankers and investors, economists, utility companies, manufacturers, county planners, and numerous government resource management agencies.

The results of this project have also been provided to industry and other researchers through Technical Advisory and Stake Holders Boards, an industry outreach program, digital project databases, and a project Web page. Project results were also disseminated via a field trip and core workshop, displays and technical presentations at national and regional professional conventions, non-technical presentations at public meetings and forums, and other publications. Refer to the Appendix A for a complete listing of these past activities.

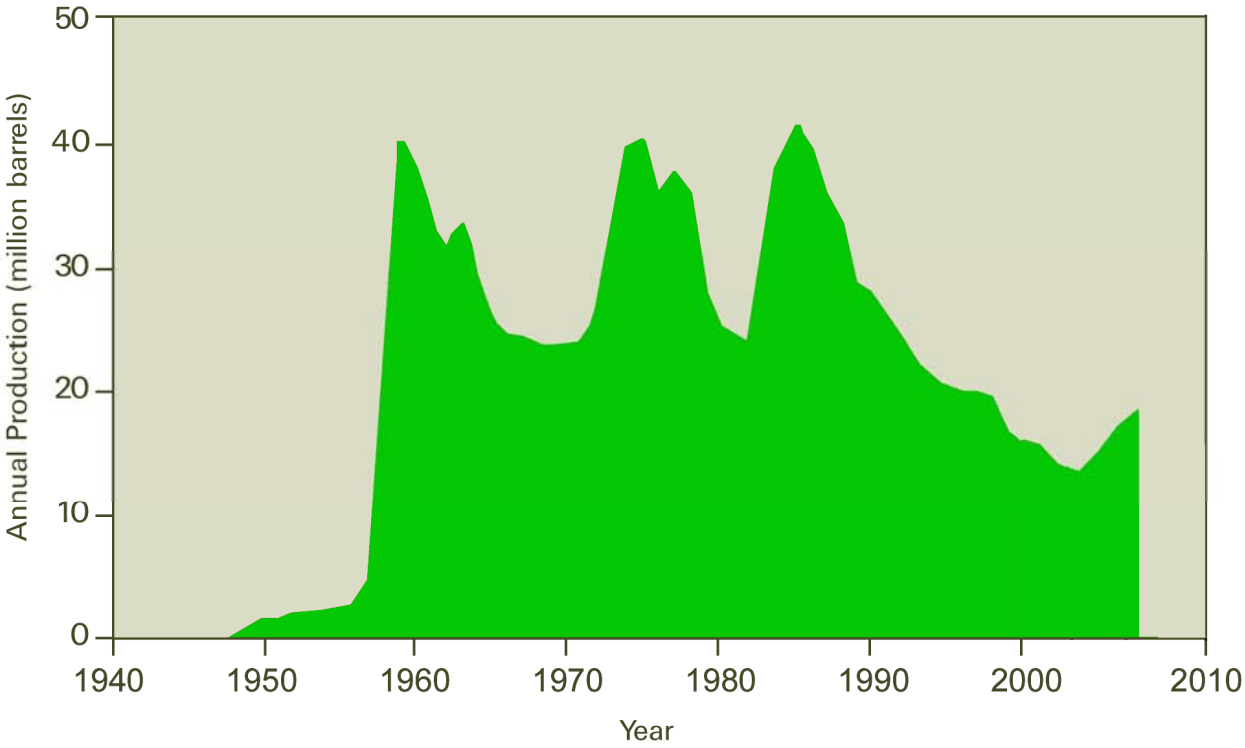


Figure 1-1. Oil production in Utah as of August 1, 2008 showing an increase due, in part, to the discovery of Covenant field in the new central Utah thrust belt Jurassic Navajo Sandstone play. Data source: Utah Division of Oil, Gas and Mining production records.

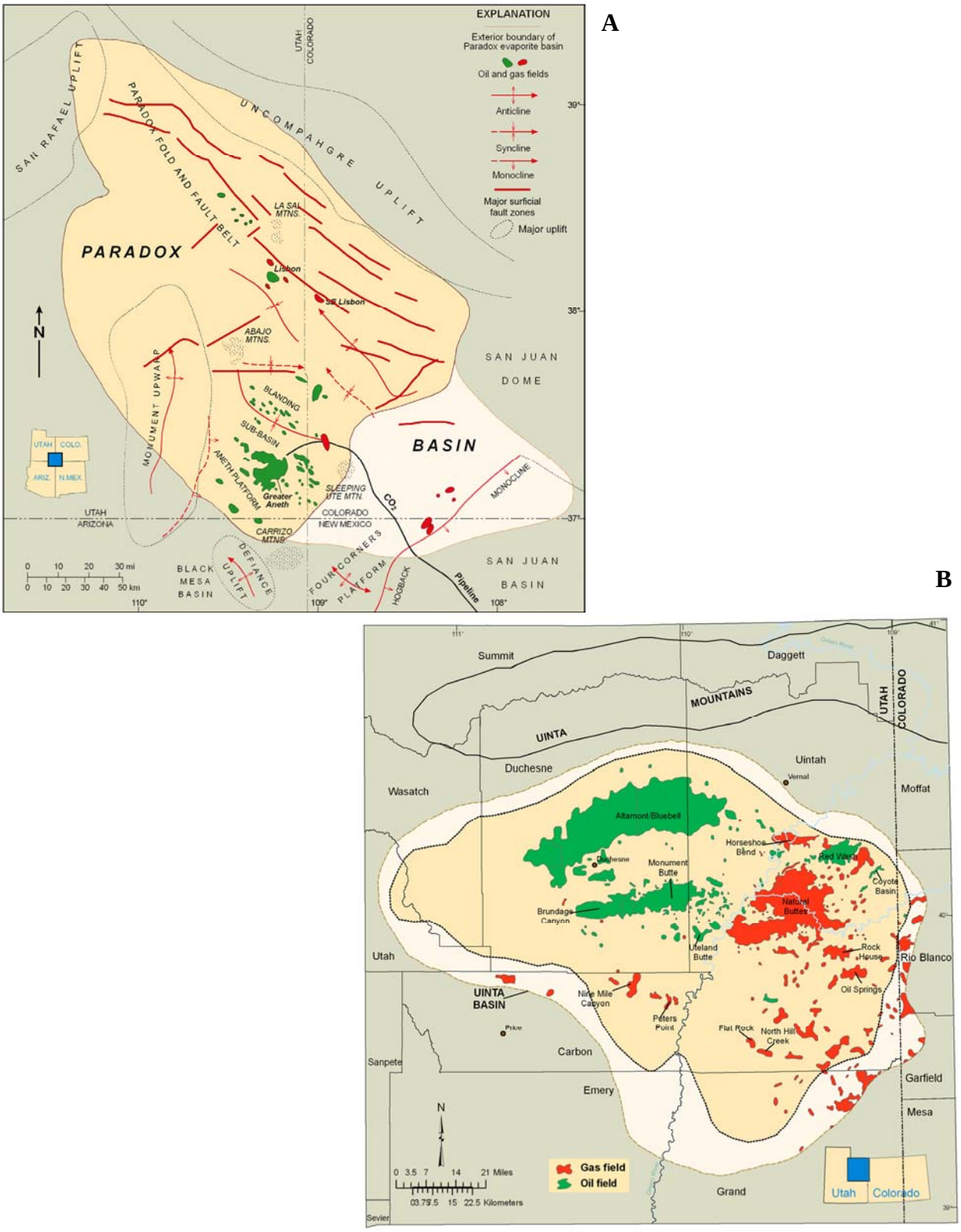


Figure 1-2. A - Oil and gas fields in the Paradox Basin of Utah, Colorado, and Arizona (modified from Kitcho, 1981; Harr, 1996). B - Oil and gas fields in the Uinta Basin of Utah and Colorado (modified from Chidsey and others, 2005). Play areas in the Paradox and Uinta Basins colored light orange.

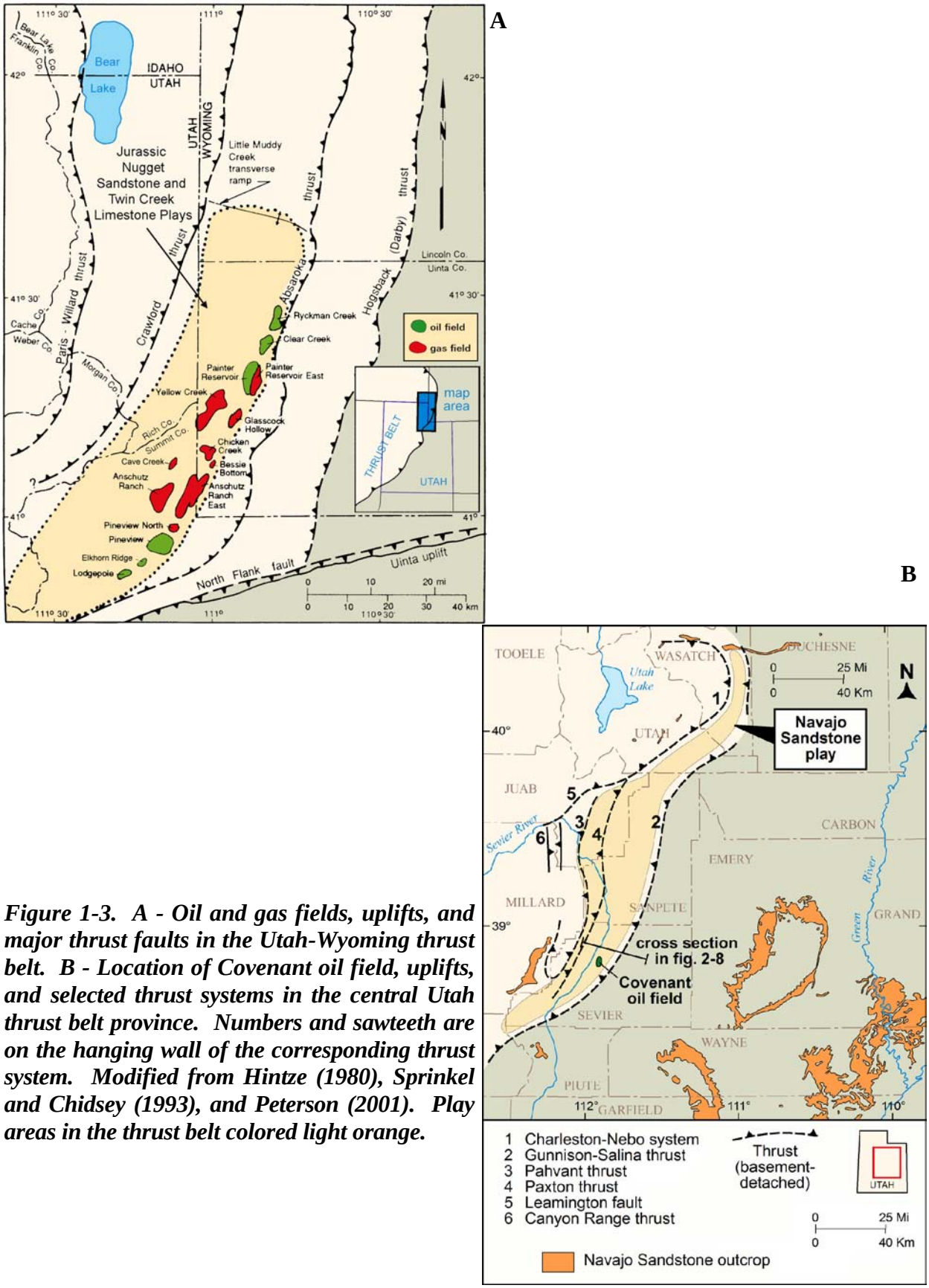


Figure 1-3. A - Oil and gas fields, uplifts, and major thrust faults in the Utah-Wyoming thrust belt. B - Location of Covenant oil field, uplifts, and selected thrust systems in the central Utah thrust belt province. Numbers and sawteeth are on the hanging wall of the corresponding thrust system. Modified from Hintze (1980), Sprinkel and Chidsey (1993), and Peterson (2001). Play areas in the thrust belt colored light orange.

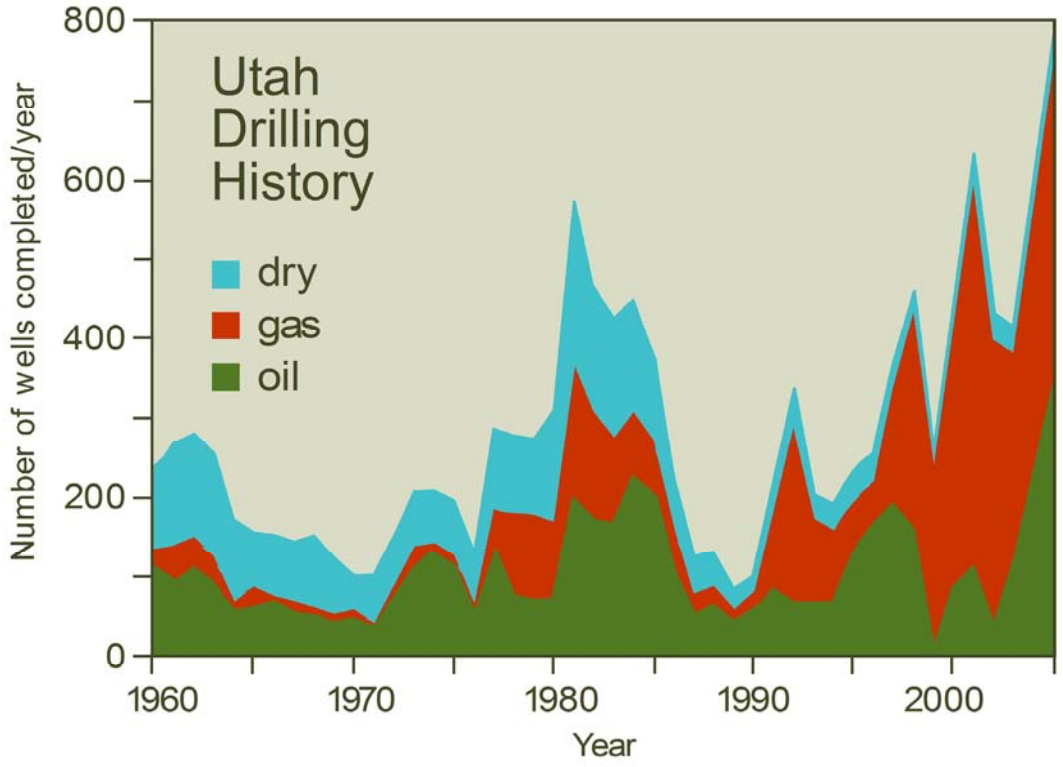


Figure 1-4. Utah drilling oil and gas history. Data source: Utah Division of Oil, Gas and Mining production records.



Figure 1-5. Oil seeps at Rozel Point, Utah, exposed during low lake level. Photographed circa 1937 (contributed by Jack N. Conley, Petroleum Geologist [from Doelling, 1980]).



Figure 1-6. Cable-tool drilling near Mexican Hat, San Juan County, Utah, circa 1920. Used by permission, Utah State Historical Society, all rights reserved.



Figure 1-7. Townspeople visiting Virgin Dome Oil Company drilling operations at Virgin oil field (non-commercial), Washington County, Utah, in 1919. Used by permission, Utah State Historical Society, all rights reserved.



Figure 1-8. Wildcat well by the Western Empire Petroleum Company on the Coalville anticline of the Utah thrust belt, Summit County, drilled in 1922; view to the northwest. Used by permission, Utah State Historical Society, all rights reserved.

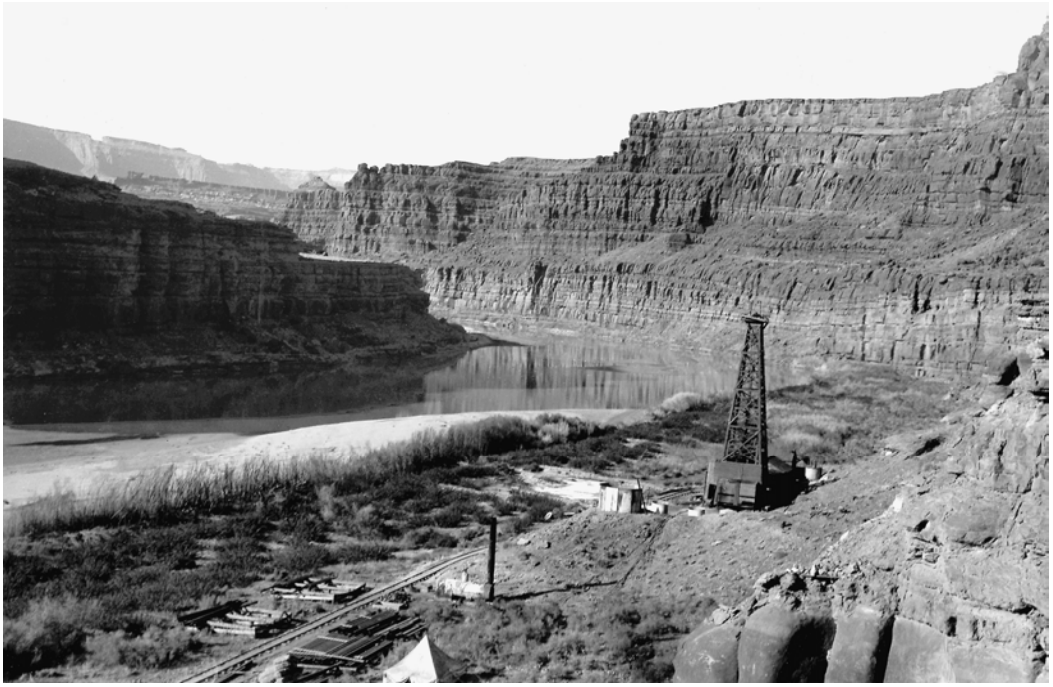


Figure 1-9. The Midwest Exploration and Utah Southern No. 1 Shafer wildcat well (section 31, T. 26 S., R. 21 E., Salt Lake Base Line and Meridian) on the Cane Creek anticline, northern Paradox Basin, Grand County, Utah, drilled in 1924; view down the Colorado River to the southwest. Used by permission, Utah State Historical Society, all rights reserved.

CHAPTER 2
MAJOR OIL-PRODUCING PROVINCES IN UTAH AND VICINITY

Thomas C. Chidsey, Jr., and Craig D. Morgan,
Utah Geological Survey

Geologic Setting

A combination of depositional and structural events created the major oil-producing provinces in the study area: Paradox Basin, Uinta Basin, and thrust belt (figures 1-2 and 1-3). Oil production in the thrust belt and Paradox Basin extends into Wyoming and Colorado, respectively, but the bulk of the production is from Utah.

The ages of the rocks exposed in Utah include every geologic eon, era, period, and epoch. Many of these rocks have the qualities necessary to create the oil reservoirs, sources, and seals that make Utah a petroleum-producing state with large, relatively unexplored areas of hydrocarbon potential.

Utah Mississippian rocks are widespread, fossiliferous, and contain one of the most complete sequences in the North America (Hintze, 1993). During the Pennsylvanian (figure 2-1A), the Paradox Basin developed in southeastern Utah where cyclic organic-rich shales, carbonates, and evaporites accumulated under restricted marine conditions in the rapidly subsiding basin. The Paradox Basin contains Utah's largest oil field, Greater Aneth. Renewed movement on deep, older basement faults in the basin formed structures, which are now oil productive in Mississippian-age carbonates.

In Early Jurassic time, Utah had an arid climate and lay 15 degrees north of the equator (figure 2-1B). It was then that the most prolific oil reservoir in the two thrust belt areas, the Nugget/Navajo Sandstone, was deposited in an extensive dune field comparable to the present Sahara. Correlative rocks form many of the spectacular canyons in the parks of southern Utah.

During the Cretaceous, compressional forces of the Sevier orogeny produced highlands in western Utah and the Western Interior Seaway covered most of eastern Utah (figure 2-1C). Extensive coal swamps formed near the coastline of fluvial- and wave-dominated deltas that migrated eastward across the state as the sea eventually retreated. The Sevier orogeny continued into the Paleocene producing the "thin-skinned" folds and faults of the thrust belt that have been such prolific oil producers in northern Utah (figure 2-1D). Concealed, deep exploration targets beneath the Sevier thrusts offer frontier-drilling opportunities in the poorly explored western half of Utah.

The Laramide orogeny, between latest Cretaceous and Eocene time, produced numerous basins and basement-cored uplifts in the Rocky Mountain states. In Utah, the Uinta Basin is the major oil contributor. During the Paleocene and Eocene (figure 2-1E), lakes Flagstaff and Uinta formed in the Uinta Basin where over 11,000 feet (3350 meters) of alluvial, marginal lacustrine (fluvial, deltaic, beach), and open lacustrine sediments accumulated in an intertonguing relationship. Recent waterflood projects have been very successful in increasing oil production in the southern part of the basin.

The principal source rocks for these provinces were deposited during the Mississippian, Pennsylvanian, Permian, Cretaceous, and Tertiary as marine and lacustrine shale. The reservoir rocks were deposited in a variety of environments including deltaic, shallow-shelf marine, eolian-dune, coastal-plain, and river-floodplain settings.

Definition of Major Oil Plays

Oil plays are geographic areas with petroleum potential caused by favorable combinations of source rock, migration paths, reservoir rock characteristics, and other factors. Numerous plays (and subplays), delineated and described in the following sections and listed below, are found in the Utah/Wyoming thrust belt, central Utah thrust belt - Hingeline, Uinta Basin, and Paradox Basin oil-producing provinces of Utah and vicinity (figures 1-2 and 1-3). For this report, we describe the major oil plays that have produced over 4.0 million bbls (0.6 million m^3) of oil as of January 1, 2008. Also included are geologic, reservoir, and production data for individual fields within those plays that have produced over 500,000 bbls (80,000 m^3) of oil as of January 1, 2008.

This report includes play portfolios for the following four major oil provinces in Utah and vicinity (southwestern Wyoming, southwestern Colorado, and northeastern Arizona): (1) the Jurassic Nugget Sandstone and Twin Creek Limestone thrust belt plays (including five subplays) in Utah and Wyoming, (2) the Jurassic Navajo Sandstone "Hingeline" play in the central Utah thrust belt, (3) the Conventional Southern Uinta Basin (including six subplays), the Conventional Northern Uinta Basin (including two subplays) and the Deep Uinta Basin Overpressured Continuous plays in Utah, and (4) the Mississippian Leadville Limestone and Pennsylvanian Paradox Formation plays (including four subplays) in the Paradox Basin of Utah, Colorado, and Arizona.

Two oil plays are not included in this report even though they both have yielded over 20 million bbls (3.1 million m^3) of oil: the Permian Kaibab Limestone/Triassic Moenkopi Formation (Timpoweap Member) Kaiparowits Basin play in south-central Utah and the Pennyslvanian Weber Sandstone Uinta uplift play in eastern Utah. There is only one field in each of these plays – Upper Valley (discovered in 1964 and has produced nearly 27.5 million bbls [4.4 million m^3], Utah Division of Oil, Gas and Mining, 2008) and Ashley Valley (discovered in 1948 and has produced nearly 20.7 million bbls [3.3 million m^3], Utah Division of Oil, Gas and Mining, 2008) in the Kaiparowits Basin and the Uinta uplift (plate 1), respectively.

Upper Valley field and the potential of the Kaiparowits Basin area have been described in detail by Campbell (1969), Peterson (1973), Sharp (1976, 1978), Montgomery (1984), Goolsby and others (1988), Doelling and Davis (1989), Allin (1990, 1993), Gautier and others (1996), and Allison (1997). Upper Valley is located on the flank of an elongate, north-northwest to south-southeast-trending surface anticline. However, the oil has been hydrodynamically displaced to the west flank of the structure. Many wells were drilled both prior to and since the discovery of Upper Valley targeting the crests of numerous surface structures in the Kaiparowits Basin rather than the more risky flanks. Therefore, remaining potential may be significant along those flanks but with the designation of a major part of the region as the Grand Staircase-Escalante National Monument in 1996, it is unlikely that further exploration will occur and thus we elected to omit the Kaiparowits Basin play from this report (the reader should refer to the studies listed above when evaluating the Permian Kaibab Limestone/Triassic Moenkopi Formation Kaiparowits Basin play).

Ashley Valley field and the potential of the Weber Sandstone north of the Uinta Basin Boundary fault along the south flank of the Uinta Mountains have been described in detail by Peterson (1950, 1957, 1961), Johnson (1964), Hefner and Barrow (1992), Hemborg (1993), Larson (1993), Gautier and others (1996), Johnson (2003), and Chidsey and Sprinkel (2005).

The Weber Sandstone also serves as a ground-water aquifer for the region. Recharge occurs in high-elevation areas where the Weber crops out. These hydrodynamic conditions suggest that Permian-sourced oil in the Weber may have been flushed to the south by fresh ground water moving from the north and northwest, thus leaving the best but limited oil potential closest to the Uinta Basin Boundary fault where Cretaceous-sourced oil contributed to the hydrocarbon system. Oil remains in the Ashley Valley structure possibly because faulting acted as barriers or baffles to ground-water flow. Potential drilling targets require the same general structural configuration (Chidsey and Sprinkel, 2005). Since 1948, over 60 Weber exploratory wells have been drilled in the region to find additional fields like Ashley Valley field. Targets include subtle anticlines on trend with Ashley Valley and major surface structures. Other wells have also tested the Weber potential beneath basement-involved thrusts. None have been successful. Thus, with little industry success or interest in the Weber Sandstone based on the drilling history and relatively limited potential, we also elected to omit the play from this report (the reader should refer to the studies listed above when evaluating the Weber Sandstone Uinta uplift play).

Overview of Major Oil-Producing Provinces

The following are general descriptions of the major oil-producing provinces for Utah and vicinity (data sources [monthly and cumulative production, number of active wells, and number of active fields]: Wyoming Oil & Gas Conservation Commission, 2008; Colorado Oil & Gas Conservation Commission, 2008; Steve Rauzi, Arizona Geological Survey, written communication, 2006; Utah Division of Oil, Gas and Mining, 2008).

Utah-Wyoming Thrust Belt

The Utah-Wyoming-Idaho salient of the Cordilleran thrust belt is defined as the region north of the Uinta Mountains of northeastern Utah and south of the Snake River Plain of Idaho, with the Green River basin of Wyoming forming the eastern boundary (figure 2-2). Thrusting extends westward into the Great Basin for more than 100 miles (160 km). The thrust belt formed during the Sevier orogeny (Armstrong, 1968); in northwestern Utah, thrusting began in latest Jurassic or earliest Cretaceous time. The Sevier thrust system consisted of, from west to east, the thrust belt, a foredeep basin, a forebulge high, and a back-bulge basin (figure 2-3) (Willis, 1999).

The Sevier orogeny was the result of crustal shortening caused by tectonic convergence from subduction of the Farallon plate along the western North America. Shortening in basement and igneous rocks to the west was transferred along weak bedding planes in the shale and evaporate beds in the thick Paleozoic and Mesozoic section to the east. The result was a detached (not involving basement rock) or “thin-skinned” style of compressional deformation involving mainly sedimentary rocks in the Utah-Wyoming-Idaho thrust belt (figure 2-4) (Willis, 1999). The Sevier orogeny overlaps with the Late Cretaceous to Oligocene Laramide orogeny which produced basement-cored uplifts reflecting an eastward extension of the west coast subduction zone (Hintze, 2005).

The eastward-directed compression migrated from west to east and, thus the stacked thrust plates are oldest in the west and youngest in the east (figure 2-4). When the wedge of rock within a thrust plate became too thick during eastward migration, movement along the thrust fault ended and stepped forward to create a new, younger thrust. These younger, eastern thrusts

tended to move less than the older, western thrusts. They also are thinner and form smaller amplitude folds (Willis, 1999).

There are four major thrust faults in the region (from west to east and oldest to youngest): the Paris-Willard, Crawford, Absaroka, and Hogsback (Darby) (figures 1-3A and 2-5). At the time of their emplacement the accompanying forebulge was east of Utah. These thrust plates may be up to 50,000 feet (15,000 m) thick and transported as much 60 miles (100 km) east (Willis, 1999; Hintze, 2005). The thrusts generally trend in a north-northeast direction. The leading edges of these faults are listric in form and structurally complex, with numerous folds and thrust splays (figure 2-6). The stacked thrust plates near the leading edge of the thrust belt overlie younger organic-rich Cretaceous marine shale which is the source for the hydrocarbons in Utah and Wyoming fields.

During later Miocene to Holocene regional extension, some thrust faults experienced "relaxation" and became listric normal faults along previous thrust fault planes. Many of these later listric normal faults become bedding plane faults within the Jurassic Preuss salt or shale above thrust-induced structures below. Thus, the surface geology often does not reflect the deeper structural configuration.

Associated with thrusting was synorogenic deposition (figure 2-5 and 2-7). Synorogenic deposits are represented by thick conglomerates, such as the Echo Canyon and Weber Canyon Conglomerates. They grade eastward into fluvial, coastal-plain, and deltaic deposits (Willis, 1999). Synorogenic deposits are used to determine the age of thrust emplacement. The Absaroka thrust moved in Late Cretaceous time (pre-mid-Santonian to pre-Campanian-Maastrichtian according to Royse and others, 1975). Most thrust belt oil fields are on the Absaroka thrust plate (figure 1-3A). Traps form on discrete, seismically defined, subsidiary closures along strike on major ramp anticlines (Lamerson, 1982).

The oil plays (and subplays), and their reservoirs, trapping mechanisms, source rocks, production data, and other general information pertaining to the Utah/Wyoming thrust belt province are outlined below:

- Major oil plays (and subplays):
  - Jurassic Nugget Sandstone thrust belt play
    - Subplays: Nugget Sandstone Absaroka thrust - Mesozoic-cored shallow structures subplay
      Nugget Sandstone Absaroka thrust - Mesozoic-cored deep structures subplay
      Nugget Sandstone Absaroka thrust - Paleozoic-cored shallow structures subplay
  - Jurassic Twin Creek Limestone thrust belt play
    - Subplays: Twin Creek Limestone Absaroka thrust - Mesozoic-cored shallow structures subplay
      Twin Creek Limestone Absaroka thrust - Paleozoic-cored shallow structures subplay

- Major oil reservoirs: Jurassic Nugget Sandstone, eolian dune sandstone; Jurassic Twin Creek Limestone, shallow marine limestone.

- Trapping mechanisms: anticlines in the hanging walls of detached (not involving basement rocks) thrust systems, and untested subthrust structures (beneath detached and basement-cored faults).

- Source rocks: Cretaceous Mowry Shale; possibly Permian Phosphoria Formation.

- Timing of generation and migration of oil: hydrocarbon generation occurred since early Oligocene.

- First commercial discovery: Pineview field, 1975.

- Number of active oil fields/wells: 15 fields/214 wells.

- Average 2008 monthly production: 173,000 bbls (27,500 m^3) of oil, 9.5 billion cubic feet (BCF) (0.27 BCM) of gas.

- Cumulative production as of August 1, 2008: 303 million bbls of (48.1 million m^3) oil, 5.2 trillion cubic feet (TCF) (0.15 TCM) of gas.

- Types of enhanced oil recovery techniques: gas re-injection to maintain pressure, horizontal drilling.

- Major pipelines: Pacific Energy Partners LP (8 inch-oil),
  Rocky Mountain Pipeline Systems LLC (10 inch-, 16 inch-oil), Chevron Pipeline Co. (10 inch-oil), Pioneer Pipeline Co. (8 inch-products), Enterprise Products Partners LP (6 inch-products), Questar Pipeline Co. (10 inch-, 12 inch-, 16 inch-, 18 inch-, 20 inch-, 24 inch-gas), Kern River Gas Transmission Co. (36 inch-gas), Williams Gas Pipeline - Northwest (22 inch-gas), Anadarko Rocky Mountain Energy (10 inch-hydrogen sulfide).

- Outcrop analogs in Utah: structural – northern Wasatch Range and Crawford Mountains; reservoirs – northern Wasatch Range, Uinta uplift, central and southern Utah.

Central Utah Thrust Belt – Hingeline

The central Utah thrust belt is part of the Sevier (Cordilleran) thrust belt (figure 2-2) that trends through the entire state, also referred to by many geologists as "the Hingeline." It is loosely defined as the portion of the thrust belt south of the Uinta Mountains of northeastern Utah, trending through central Utah to the Marysvale–Wah Wah volcanic complex of south-central Utah. Classic papers describing and interpreting the geology of the Hingeline region include those of Eardley (1939), Kay (1951), Armstrong (1968), and Stokes (1976). Throughout this area's geologic history, the Hingeline has marked a pronounced boundary between different geologic terranes and processes. From Late Proterozoic to Triassic time, it marked the boundary between a very thick succession of sediments deposited in western Utah and a thin succession deposited in eastern Utah. During Cretaceous and early Tertiary time, the Hingeline coincided with and influenced thrusts at the eastern edge of the Sevier orogenic belt. Today in central Utah

it marks the general boundary between the Basin and Range and Colorado Plateau physiographic provinces.

In reality, the Hingeline is an area rather than a line, and includes geologic features common in both the Basin and Range and Colorado Plateau physiographic provinces: Sevier orogenic thrust faults, basement-cored Late Cretaceous–Oligocene Laramide uplifts (plateaus and the Wasatch monocline), and Miocene to Holocene normal faults. Paleozoic rocks thicken westward across the Hingeline area from thin cratonic deposits, whereas the Upper Cretaceous section includes thick synorogenic deposits reflecting proximity of the Sevier orogenic belt to the west. Several depositional environments during the Mississippian and Permian produced organic-rich deposits capable of generating hydrocarbons.

An extensional fault system, including the high-angle, basement-involved "ancient Ephraim fault," was located in central Utah during the Middle Jurassic (Moulton, 1976; Schelling and others, 2005). In the Late Jurassic, Utah was mostly a forebulge high (Willis, 1999). In central Utah, large-scale thrust sheets were emplaced during latest Jurassic through early Tertiary time by compression of the actively evolving foreland basin (Schelling and others, 2005; DeCelles and Coogan, 2006). The youngest evidence of thrust faulting is 40 million years old in central Utah (Lawton, 1985; Decelles and others, 1995; Lawton and others, 1997; Willis, 1999; Constenius and others, 2003; Decelles, 2004; DeCelles and Coogan, 2006). Thrusting extended westward for more than 100 miles (160 km).

Major thrust faults in central Utah (from west to east) include the Canyon Range, Leamington, Pahvant (Royse, 1993), Paxton, Charleston-Nebo, and the Gunnison-Salina (Villien and Kligfield, 1986; Schelling and others, 2007) (figure 1-3). These thrust faults represent detached, thin-skinned, compressional styles of deformation, with eastward combined movement of greater than 90 miles (140 km) for the Canyon Range and Pahvant thrusts (DeCelles and Coogan, 2006). Easternmost thrust systems moved less than western thrust systems and are generally younger; the Canyon Range thrust was emplaced during latest Jurassic–Early Cretaceous time, the Pahvant thrust was emplaced in Albian time, the Paxton thrust was emplaced in Santonian time, and the Gunnison-Salina thrust was active from late Campanian through early Paleocene time (DeCelles and Coogan, 2006). The Ephraim fault and other Middle Jurassic faults may have also experienced additional Laramide-age (Maastrichtian through Eocene) movement.

Surface traces of the thrust faults generally trend in a north-northeast direction. Some of the thrust faults do not extend to the surface, and the term "blind" thrust is applied to buried faults like the Gunnison-Salina thrust. The Pahvant, Paxton, and Gunnison-Salina thrust systems contain Lower Cambrian through Cretaceous strata. Jurassic shale, mudstone, and evaporite beds serve as the main glide planes along the hanging-wall flats of these thrust systems.

The leading edges of the thrust faults are listric in form and structurally complex. They include numerous thrust splays, back thrusts, duplex systems (particularly in the younger eastern thrusts), fault-propagation folds (fault-bend folds), and ramp anticlines such as the huge fold that makes up most of Mount Nebo (near the city of Nephi) along the Charleston-Nebo thrust system where overturned upper Paleozoic and attenuated Triassic and Jurassic rocks are spectacularly displayed. The duplex systems are similar to those found in the Alberta Foothills in the eastern Canadian Rocky Mountains (Dahlstrom, 1970); these types of features are not present in the Utah-Wyoming-Idaho salient of the thrust belt to the north.

Central Utah thrust plates, like the Canyon Range thrust plate, are as much as 36,000 feet (12,000 m) thick (DeCelles and Coogan, 2006), although younger eastern plates tend to be

thinner. The eastern plates also deformed into smaller-amplitude fault-propagation folds and ramp anticlines than did western plates (Willis, 1999). Middle Jurassic extensional faults, such as the Ephraim and similar faults in the region, determined the position of these ramp anticlines and associated duplexes along thrust systems by acting as buttresses to plate movement (Schelling and others, 2005). However, a blind, low-angle thrust fault continues east of the Ephraim fault within the Jurassic Arapien Shale–Carmel Formation under the Wasatch Plateau (Neuhauser, 1988). Smaller imbricate faults from the décollement form fault-propagation/fault-bend folds, which are some of the producing anticlines along the Wasatch Plateau.

Neogene reactivated movement along many thrust ramps, splays, and associated back thrusts formed listric normal faults. Other normal faults related to Basin-and-Range extension dissected thrust plates into additional, compartmentalized blocks (Schelling and others, 2005). The Wasatch monocline and other monoclinal structures formed at this time. Some local ductile deformation of Jurassic evaporites further complicated the structural picture of the region (Witkind, 1982). Potential hydrocarbon traps form on discrete, seismically defined, subsidiary closures along strike on major ramp anticlines and fault-propagation/fault-bend folds.

The oil play, reservoir, trapping mechanisms, source rocks, production data, and other general information pertaining to the central Utah thrust belt – Hingeline province are outlined below:

- Major oil plays: Jurassic Navajo Sandstone central Utah thrust belt – Hingeline play

- Major oil reservoir: Jurassic Navajo Sandstone, eolian dune sandstone.

- Trapping mechanisms: anticlines in the hanging walls of detached (not involving basement rocks) thrust systems created by thrust imbricates, or imbricate fans above, and antiformal stacks of horses forming duplexes below the major thrusts (figure 2-8).

- Source rocks: organic-rich marine shale within the Mississippian Manning Canyon Shale, Delle Phosphatic Member of the Deseret Limestone, Doughnut Formation, or Chainman Shale; possibly Permian Park City/Phosphoria Formation (figure 2-8).

- Timing of generation and migration of oil: most of the hydrocarbon generation and migration probably occurred during Cretaceous to early Tertiary. However, some hydrocarbon generation and migration probably began as early as Permian or Triassic time in the older Paleozoic rocks and as late as Tertiary time in Mesozoic rocks.

- First commercial oil discovery: Covenant field, 2004.

- Number of active oil fields/wells: one field/ten wells.

- Average 2008 monthly production: 195,000 bbls (31,000 m^3) of oil.

- Cumulative production as of August 1, 2008: 2,000,000 bbls (318,000 m^3) of oil.

- Types of enhanced oil recovery techniques: possible future carbon dioxide/nitrogen injection.

- Major pipelines: Questar Pipeline Co. (18 inch-, 24 inch-gas), Questar Gas Co. (8 inch- and 10 inch-gas), Kern River Gas Transmission Co. (36 inch-gas).

- Outcrop analogs in Utah: San Rafael Swell, Pahvant Range, southern Wasatch Range, and throughout the Colorado Plateau of southern Utah.

Uinta Basin

The Uinta – Piceance Province in northeastern Utah and northwestern Colorado, as defined by the U.S. Geological Survey (USGS), contains the contiguous outcrops of the Maastrichtian and Tertiary rocks, and also includes the southwest- to northeast-trending Wasatch Plateau and Castle Valley (Dubiel, 2003). Our discussion will be restricted to the Uinta Basin portion of the province (figure 2-9), which incorporates a small portion of the western flank of the Douglas Creek Arch that separates the Uinta and Piceance basins. The Uinta Basin covers nearly 16,000 square miles (41,000 km^2). The Uinta Basin (excluding the Wasatch Plateau and Castle Valley) is a topographic and structural trough that is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank (figure 2-10) bounded by the San Rafael and Uncompahgre uplifts.

The Uinta Basin formed in Late Cretaceous (Maastrichtian) time, when a large structural sag with internal drainage formed. The earliest deposits in the intermontane basin were predominantly alluvial (Ryder and others, 1976) with some shallow lacustrine and paludal deposits that comprise the North Horn Formation. In early late Paleocene time, a large lake known as ancestral Lake Uinta developed in the basin (Franczyk and others, 1992) (includes Lake Flagstaff of some workers). Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine sediments that make up the Green River Formation. Alluvial redbed and floodplain deposits that are laterally equivalent to, and intertongue with, the Green River form the Colton (Wasatch) Formation (figure 2-11). The Eocene Uinta Formation and the Eocene to lower Oligocene Duchesne River Formation overlie the Green River.

The significant oil plays in the Uinta Basin are part of the Green River Total Petroleum System (TPS). The USGS defines the Green River TPS as a complex of entirely continental rocks (North Horn, Wasatch, Colton, Green River, Uinta, and Duchesne River Formations) that host gilsonite veins, oil shales, tar sands, and oil and gas, all sourced from lacustrine rocks within the Paleocene and Eocene Green River Formation (Dubiel, 2003). Source rocks are: (1) type I kerogen from the open-lacustrine facies, (2) type I, II, and III, kerogen from the marginal-lacustrine facies, and (3) type III kerogen from alluvial facies (Dubiel, 2003).

The maximum depth to the base of the Green River TPS is about 20,000 feet (6100 m) along the axis of the Uinta Basin (Fouch and others, 1994). Operators typically assign all strata containing red beds to the Wasatch or Colton formations; however, oil and gas production is mostly from tongues of the Green River Formation within the alluvial Wasatch and Colton (Fouch and others, 1992; Fouch and others, 1994).

The dominant sediment source for the Green River and Colton formations in the Cedar Rim, Altamont, Bluebell, and Red Wash fields was from the north, while the sediment source for the greater Monument Butte, Duchesne, Brundage Canyon, Sower Canyon, Antelope Creek, and Uteland Butte fields, was from the south (figure 2-12). As a result, the deposition and the

resulting reservoir properties are significantly different between south-sourced and north-sourced depositional systems.

The USGS (Dubiel, 2003) defines two assessment units in the Green River TPS within the Uinta Basin: (1) the Deep Uinta Overpressured Continuous Oil Assessment Unit (AU 50200561) and (2) the Uinta Green River Conventional Oil and Gas Assessment Unit (AU 50200501) (figure 2-13). The Green River Conventional Oil and Gas Assessment Unit extends farther west than the Uinta Basin boundary. The western boundary of the Uinta Basin in Wasatch and Utah counties is defined by the Charleston-Nebo thrust, and Maastrichtian and Tertiary rocks beneath the thrust define the assessment unit boundary. As a result, the assessment unit boundary extends beyond the basin boundary.

The USGS (Dubiel, 2003) defines the Deep Uinta Overpressured Continuous Oil Assessment Unit by overpressured (gradient >0.5 pounds per square inch per foot [psi/ft]; 11.3 kPa/m) source and reservoir rocks in the Green River Formation (figure 2-14). The overpressuring is located near the basin center mostly in the Colton Formation and Flagstaff Member of the Green River in the Altamont, Bluebell, and Cedar Rim fields. The 0.5 psi/ft (11.3 kPa/m) gradient is encountered as shallow as 8500 feet (2600 m). However, most of the high-volume, overpressured oil production is typically from 12,000 to 14,000 feet (3600-4300 m) in the Flagstaff Member.

The USGS defines the Uinta Green River Conventional Oil and Gas Assessment Unit by the distribution of normally pressured (<0.5 psi/ft [11.3 kPa/m]) oil and gas accumulations in the Green River Formation, typically at depths less than 8500 feet (2600 m) (Dubiel, 2003). The unit overlies the entire area of the Deep Uinta Overpressured Continuous Oil Assessment Unit. The Uinta Green River Conventional Oil and Gas Assessment Unit consists entirely of the part of the Green River that overlies the Colton and Wasatch formations. A transitional interval from about 8500 to 11,000 feet (2600-3400 m) is slightly overpressured (0.50 to 0.55 psi/ft [11.3-12.4 kPa/m]) but many of the reservoir characteristics are more like the overlying Conventional Northern Uinta Basin Play (CNUBP) and is discussed in that play description.

The Deep Uinta Overpressured Continuous Oil Assessment Unit and the Deep Uinta Basin Overpressured Continuous Play (DUBOCP) have the same boundaries. We divide the Uinta Green River Conventional Oil and Gas Assessment Unit into a Conventional Southern Uinta Basin Play (CSUBP) and a CNUBP, which have some overlap (figures 2-15 and 2-16); each are further divided into subplays. The subplays are based on depositional environments of the reservoir rocks which were strongly influenced by the: (1) sediment source, (2) gradient of the depositional slope, and (3) energy regime of the environment which affected the amount of sediment reworking (figure 2-17).

Most of the crude oils produced from the Green River TPS in the Uinta Basin are characterized as yellow or black wax. Production from the DUBOCP is dominantly yellow wax while most of the oil production from the CNUBP and CSUBP is black wax. Asphaltine oil has been produced from a few shallow wells in the Duchesne interval of fractured shale/marlstone subplay in the CSUBP. Associated gas is produced from the Green River TPS and typically has a high heat value - greater than 1000 British thermal units per cubic feet (Btu/ft^3).

The oil plays (and subplays), reservoirs, trapping mechanisms, source rocks, production data, and other general information pertaining to the Uinta Basin province are outlined below:

- Major oil plays (and subplays):
  - Conventional Northern Uinta Basin play

Subplays: Conventional Bluebell subplay
Conventional Red Wash subplay

- Conventional Southern Uinta Basin play

Subplays: Conventional Uteland Butte interval subplay
Conventional Castle Peak interval subplay
Conventional Travis interval subplay
Conventional Monument Butte interval subplay
Conventional Beluga interval subplay
Conventional Duchesne interval fractured shale/marlstone subplay

- Deep Uinta Basin Overpressured Continuous play

- Major oil reservoirs: Eocene Green River and Wasatch (Colton) formations, lacustrine to alluvial channel and bar sandstone.

- Trapping mechanisms: stratigraphic conventional and basin centered.

- Source rocks: Eocene lacustrine shale.

- Timing of oil generation and migration: peak generation occurred during maximum burial between 30 to 40 Ma and continues today in the deepest part of the basin. Vertical and lateral migration began prior to peak generation.

- First commercial oil discovery: oil at Roosevelt field, 1949.

- Number of active oil fields/wells: 51 fields/ 5279 wells.

- Average 2008 monthly production: 927,000 bbls (147,000 m^3) of oil, 16 BCF (0.45 BCM) of gas.

- Cumulative production as of August 1, 2008: 528 million bbls (84 million m^3) of oil, 2.6 TCF (0.7 TCM) of gas.

- Types of enhanced oil recovery techniques: waterflood in the Green River Formation.

- Major pipelines: Chevron Pipeline Co. (10 inch-oil [2 lines]), Colorado Interstate Gas Co. (20 inch-gas), Enterprise Products Partners (10 inch- and 16 inch-products), Questar Pipeline Co. (16 inch- and 20 inch-gas) Williams Gas Pipeline - Northwest (26 inch-gas).

- Outcrop analogs in Utah: Roan and Badlands Cliffs, and Raven Ridge, central Utah plateaus.

Paradox Basin

The Paradox Basin is located mainly in southeastern Utah and southwestern Colorado with small portions in northeastern Arizona and the northwestern corner of New Mexico (figure 1-2A). The Paradox Basin is an elongate, northwest-southeast-trending, evaporitic basin that predominately developed during the Pennsylvanian, about 330 to 310 million years ago (Ma). The most obvious structural features in the basin are the spectacular anticlines that extend for miles in the northwesterly trending fold and fault belt. The events that caused these and many other structural features to form began in the Proterozoic, when movement initiated on high-angle basement faults and fractures 1700 to 1600 Ma (Stevenson and Baars, 1986, 1987). During Cambrian through Mississippian time, this region, as well as most of eastern Utah, was the site of typical thin, marine deposition on the craton while thick deposits accumulated in the miogeocline to the west (Hintze, 1993). However, major changes began in the Pennsylvanian when a pattern of basins and fault-bounded uplifts developed from Utah to Oklahoma as a consequence of the collision of South America, Africa, and southeastern North America (Kluth and Coney, 1981; Kluth, 1986), or from a smaller-scale collision of a microcontinent with south-central North America (Harry and Mickus, 1998). One result of this tectonic event was the uplift of the Ancestral Rockies in the western United States. The Uncompahgre Highlands (uplift) in eastern Utah and western Colorado initially formed as the westernmost range of the Ancestral Rockies during this ancient mountain-building period.

The Uncompahgre Highlands are bounded along their southwestern flank by a large basement-involved, high-angle, reverse fault identified from seismic surveys and exploration drilling (Frahme and Vaughn, 1983). As the highlands rose, an accompanying depression, or foreland basin, formed to the southwest — the Paradox Basin. The form of the Paradox Basin was strongly influenced by rejuvenation of pre-existing (late Precambrian), northwesterly trending structures (Baars and Stevenson, 1981). Rapid basin subsidence, particularly during the Pennsylvanian and continuing into the Permian, accommodated large volumes of evaporitic and marine sediments that intertongue with non-marine arkosic material shed from the highland area to the northeast (figures 2-18 and 2-19) (Hintze, 1993). Deposition in the basin produced a thick cyclical sequence of carbonates, evaporites, and organic-rich shale (Peterson and Hite, 1969; Hite and others, 1984). The Paradox Basin is defined for the purposes of this study by the maximum extent of anhydrite beds in the Pennsylvanian Paradox Formation.

The present Paradox Basin includes or is surrounded by other uplifts that formed during the Late Cretaceous-early Tertiary Laramide orogeny, such as the Monument upwarp in the west-southwest, and the Uncompahgre uplift, corresponding to the earlier Uncompahgre Highlands, forming the northeast boundary (figure 1-2A). Oligocene laccolithic intrusions form the La Sal and Abajo Mountains in the north and central parts of the basin in Utah while the Carrizo Mountains in Arizona, and the Ute, La Plata, and San Miguel Mountains in Colorado were intruded along the southeastern boundary of the basin (figure 1-2A).

The Paradox Basin can generally be divided into three areas: the Paradox fold and fault belt in the north, the Blanding sub-basin in the south-southwest, and the Aneth platform in the southernmost part in Utah (figure 1-2A). The area now occupied by the Paradox fold and fault belt was also the site of greatest Pennsylvanian/Permian subsidence and salt deposition. Folding in the Paradox fold and fault belt began as early as the Late Pennsylvanian as sediments were laid down thinly over, and thickly in areas between, rising salt (Doelling, 2000). The Paradox fold and fault belt was created during the Late Cretaceous through Quaternary by a combination

of (1) reactivation of basement normal faults, (2) additional salt flowage followed by dissolution and collapse, and (3) regional uplift (Doelling, 2000). The relatively undeformed Blanding sub-basin and Aneth platform developed on a subsiding shallow-marine shelf. Each area contains oil and gas fields with structural, stratigraphic, or combination traps formed on discrete, often seismically defined, closures.

Most oil and gas produced from the Mississippian Leadville Limestone is found in basement-involved, northwest-trending structural traps with closure on both anticlines and faults (figure 2-20). Most Paradox Formation petroleum production comes from stratigraphic traps in the Blanding sub-basin and Aneth platform that locally contain phylloid algal-mound and other carbonate lithofacies buildups (figure 2-20). The sources of the petroleum are several black, organic-rich shales (the Gothic and Chimney Rock, for example) within the Paradox Formation (Hite and others, 1984; Nuccio and Condon, 1996).

The oil plays (and subplays), reservoirs, trapping mechanisms, source rocks, production data, and other general information pertaining to the Paradox Basin province are outlined below:

- Major oil plays (and subplays):
  - Mississippian Leadville Limestone Paradox Basin play
  - Paradox Formation, Paradox Basin play
    - Subplays: fractured shale subplay
      - Blanding sub-basin Desert Creek zone subplay
      - Blanding sub-basin Ismay zone subplay
      - Aneth platform Desert Creek zone subplay

- Major oil reservoirs: Devonian McCracken Sandstone Member of the Elbert Formation, subtidal to supratidal dolomite to delta-front sandstone; Mississippian Leadville Limestone, shallow-shelf marine limestone and dolomite; Pennsylvanian Paradox Formation, shallow-shelf marine limestone and dolomite in the Desert Creek and Ismay zones, and fractured units in the Cane Creek shale.

- Trapping mechanisms: stratigraphic – carbonate buildups (algal mounds, shoals, islands) sealed by anhydrite, salt, or organic-rich shale; structural – fracture zones faulted and asymmetrical anticlines; diagenetic – dolomitization and dissolution.

- Source rocks: black, organic-rich marine shale within the Pennsylvanian Paradox Formation.

- Timing of oil generation and migration: hydrocarbon generation occurred during maximum burial in the Late Cretaceous and early Tertiary with migration beginning at that time.

- First commercial discovery: Boundary Butte field, 1947.

- Number of active oil fields/wells: 97 fields/860 wells.

- Average 2008 monthly production: 353,000 bbls (56,100 m^3) of oil, 1.1 BCF (0.03 BCM) of gas.

- Cumulative production as of August 1, 2008: 575 million bbls (91.4 million m^3) of oil, 1.5 TCF (0.04 TCM) of gas.

- Types of enhanced oil recovery projects: waterflood, CO_2 flood (CO_2 provided by pipeline from McElmo Dome in Colorado or locally from the Mississippian Leadville Limestone within the Utah part of the Paradox Basin), gas injection, horizontal drilling.

- Major pipelines: Four Corners Pipeline Co. (12 inch-oil), Navajo Nation Oil and Gas Co. (16 inch-oil), Encana (10 inch-oil), TransColorado Pipeline Gathering Co. (4 inch-gas), Utah Gas Services Co. (4 inch-gas), Western Gas Resources, Inc. (16 inch-gas), Williams Gas Pipeline - Northwest (26 inch-gas), ExxonMobil/Resolute Natural Resources/Navajo Nation Oil and Gas Co. (8 inch-carbon dioxide), Enterprise Products Partners LP (10 inch-products).

- Outcrop analogs in Utah: shallow-shelf carbonates and karst features, Mississippian Madison and Deseret Limestones, south flank of the Uinta Mountains; Ismay and Desert Creek algal mounds, Pennsylvanian Paradox Formation, exposed along the San Juan River in southeastern Utah.

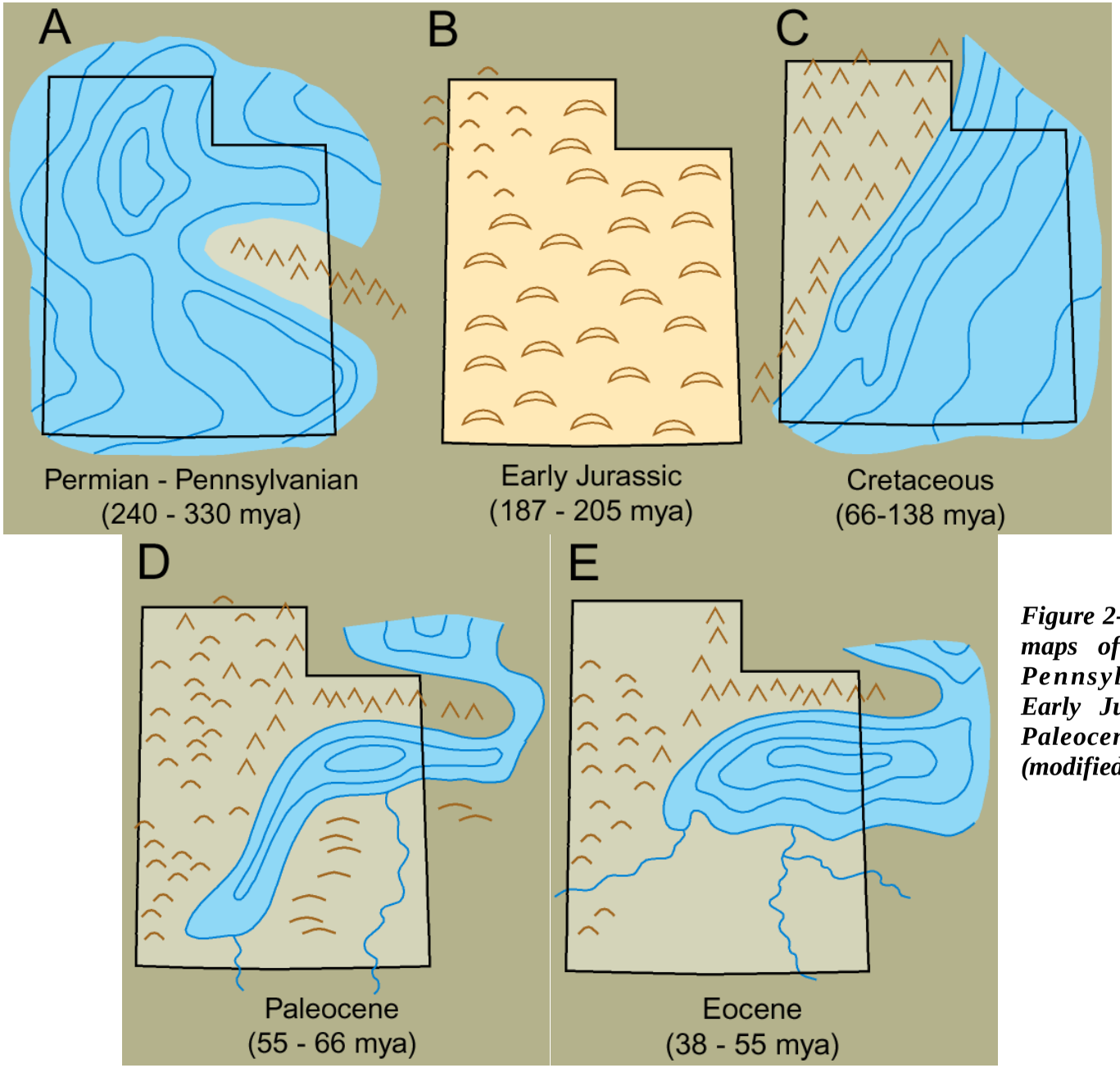


Figure 2-1. Paleogeographic maps of Utah during the Pennsylvanian-Permian, Early Jurassic, Cretaceous, Paleocene, and Eocene (modified from Stokes, 1986).

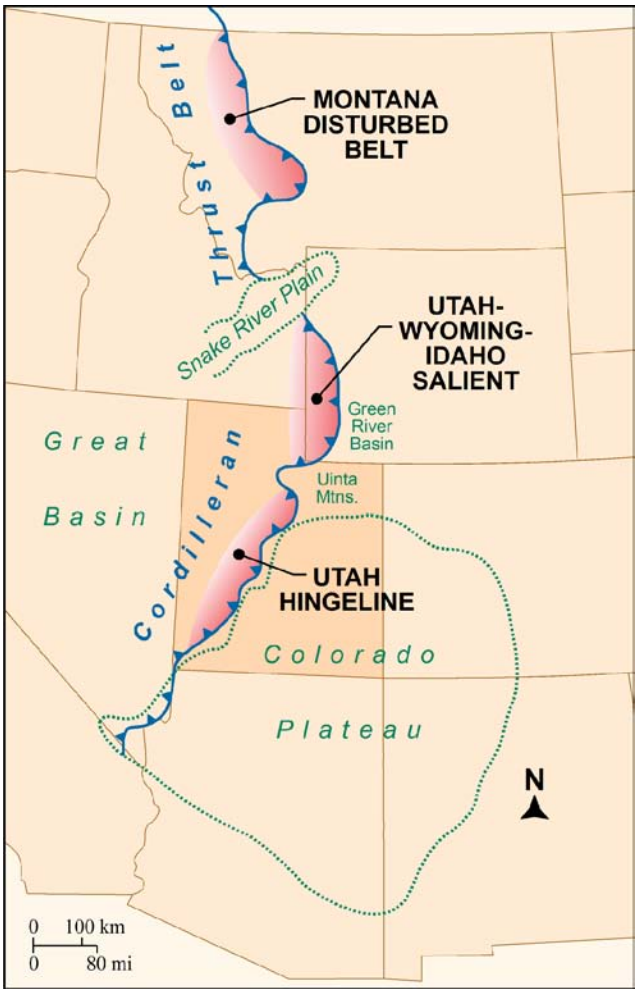


Figure 2-2. Location of the Cordilleran thrust belt including the Montana "Disturbed" belt, Utah-Wyoming-Idaho salient, and Utah "Hingeline." Modified from Gibson (1987).

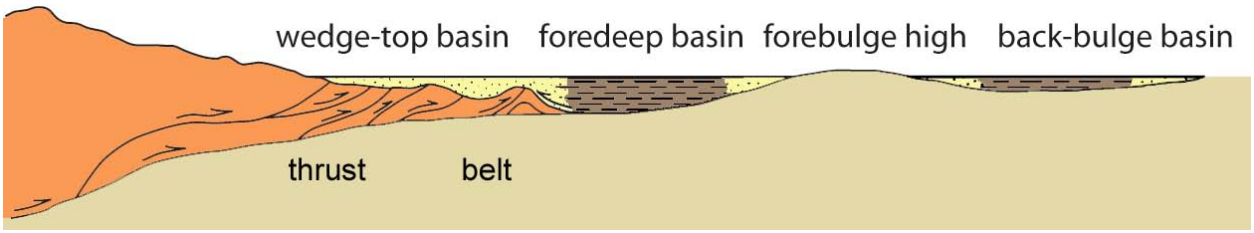


Figure 2-3. Typical parts of a thrust system (from Willis, 1999).

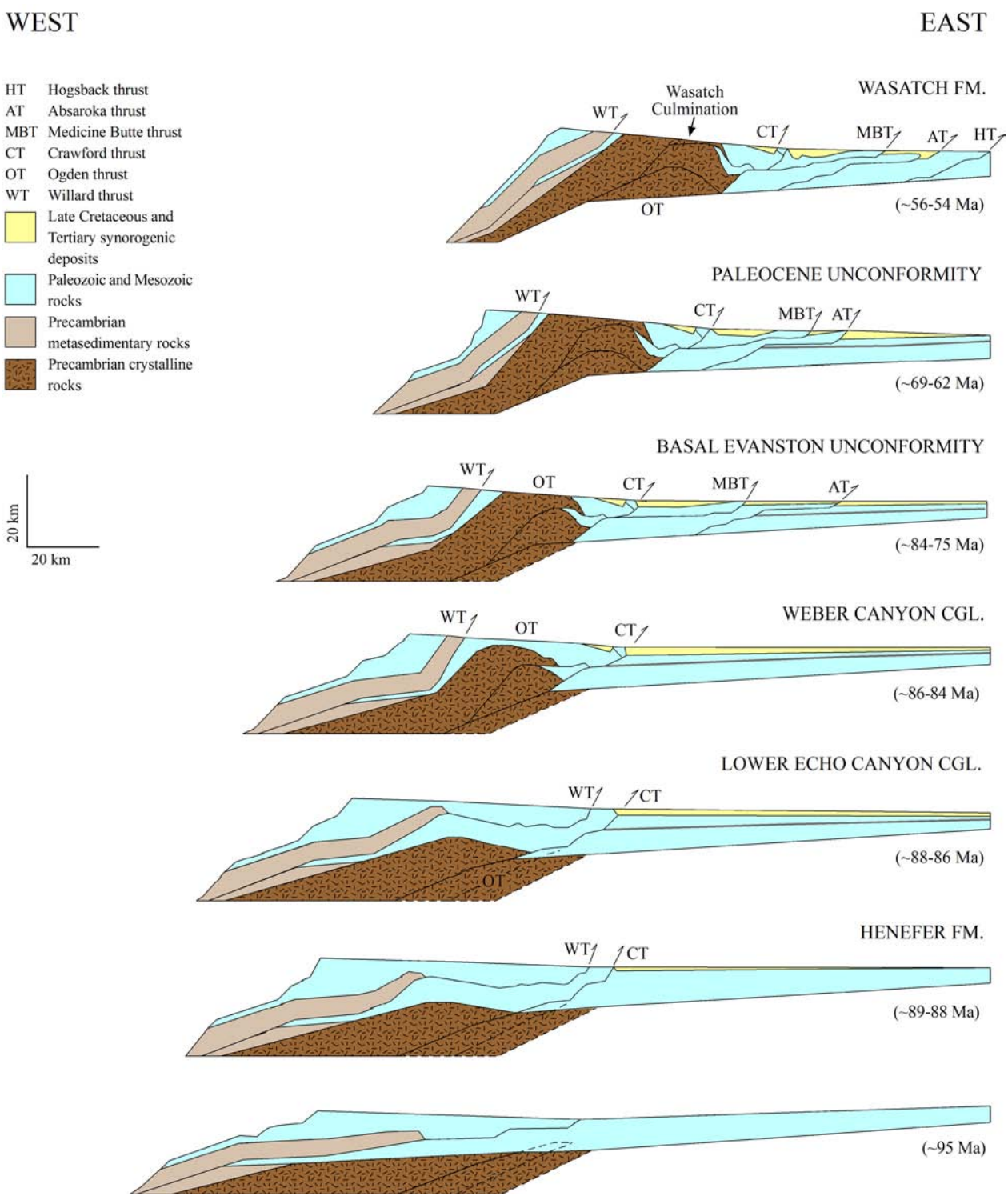


Figure 2-4. Sequential restored cross section across the Sevier thrust belt at the approximate latitude of Ogden in northern Utah showing the development of thrust faults, the eastward progression of the thrust front, and the deposition and subsequent deformation of synorogenic deposits. Modified from Coogan (1992), Yonkee (1992), DeCelles (1994), and Willis (1999).

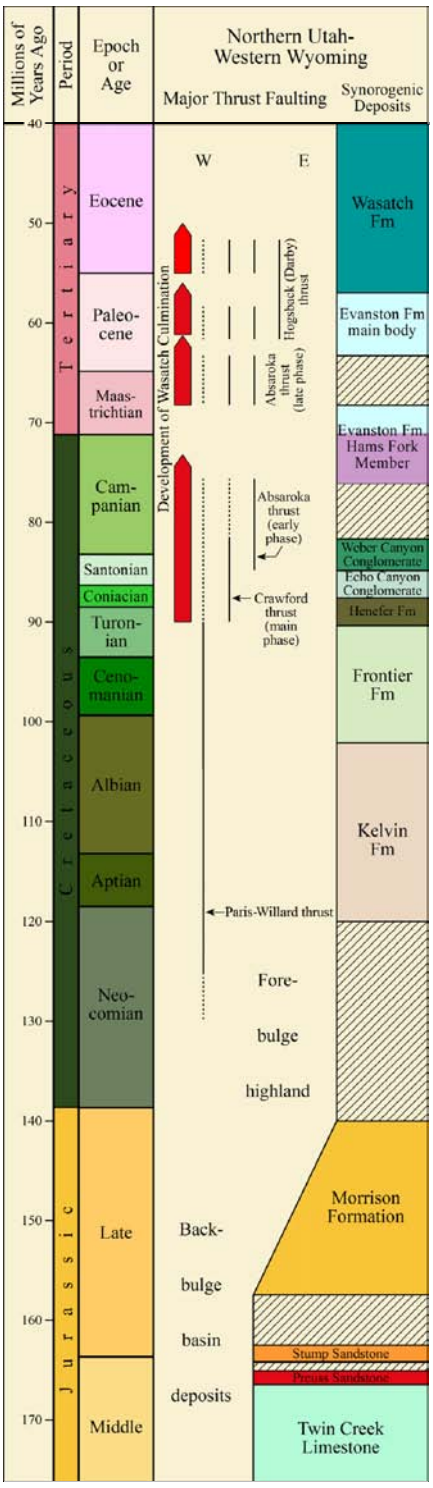


Figure 2-5. Middle Jurassic through early Eocene thrust development and related synorogenic deposits in northern Utah. Figure is generalized and several minor formations are not shown. Data from Coogan (1992), Yonkee (1992), DeCelles (1994), DeCelles and others (1995), Coogan and DeCelles (1998). Modified from Willis (1999)

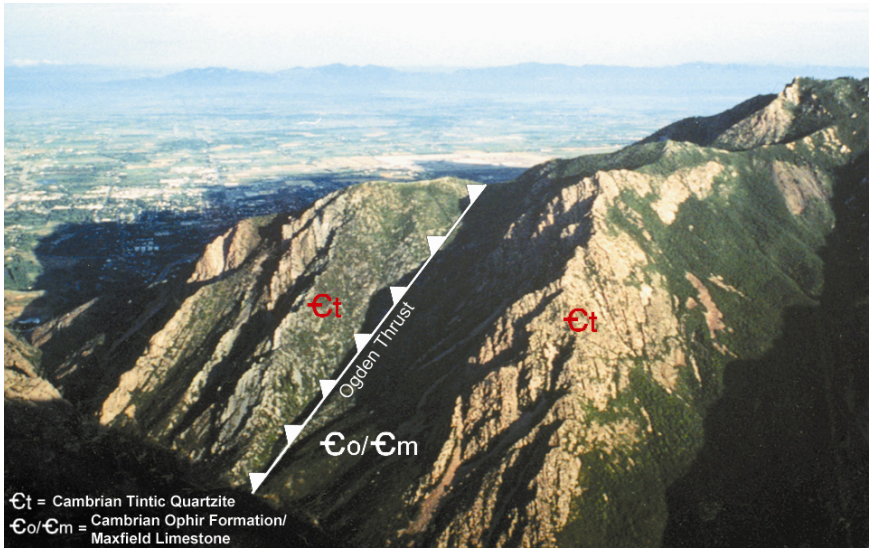


Figure 2-6. Steeply-dipping Cambrian-age Tintic Quartzite (repeated) with intervening Ophir Formation and Maxfield Limestone along the Ogden thrust, east of Ogden, Utah.

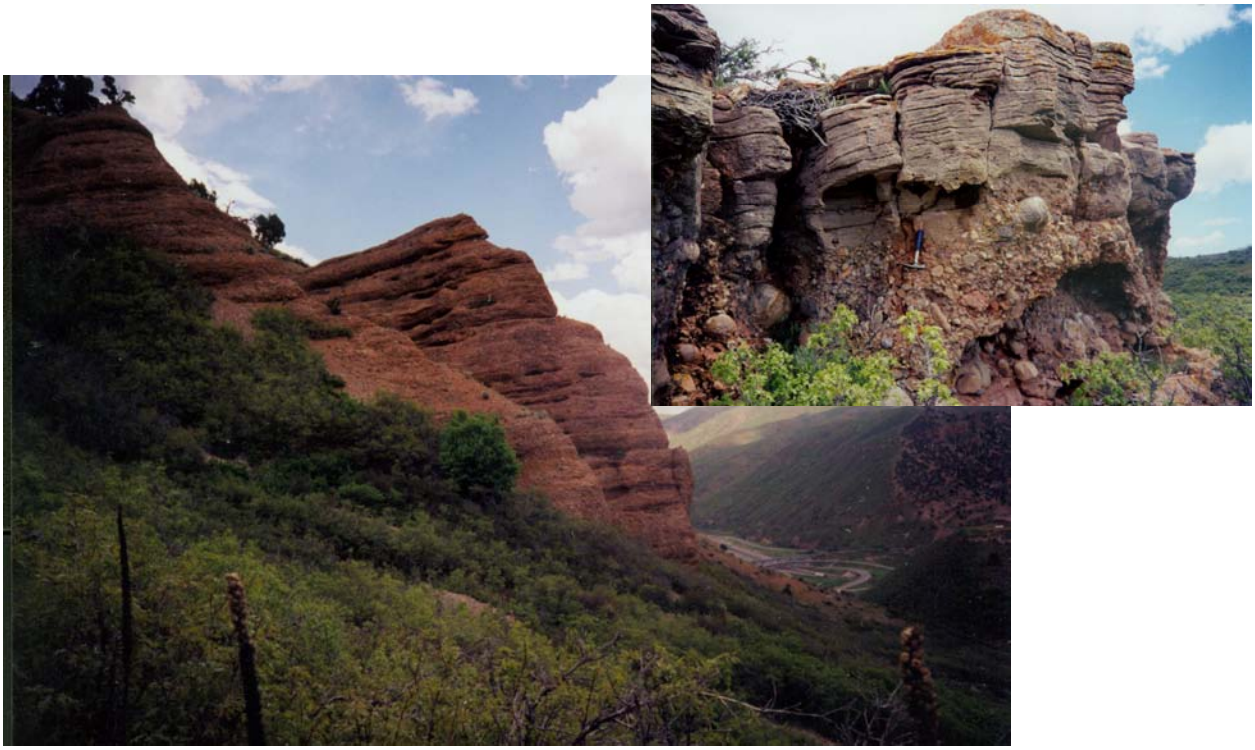


Figure 2-7. Gently dipping synorogenic Coniacian-Santonian Echo Canyon Conglomerate, near the junction of Weber and Echo Canyons, northern Utah. Inset – close up of interbedded conglomerate and sandstone. Photo by Hugh Hurlow, Utah Geological Survey.

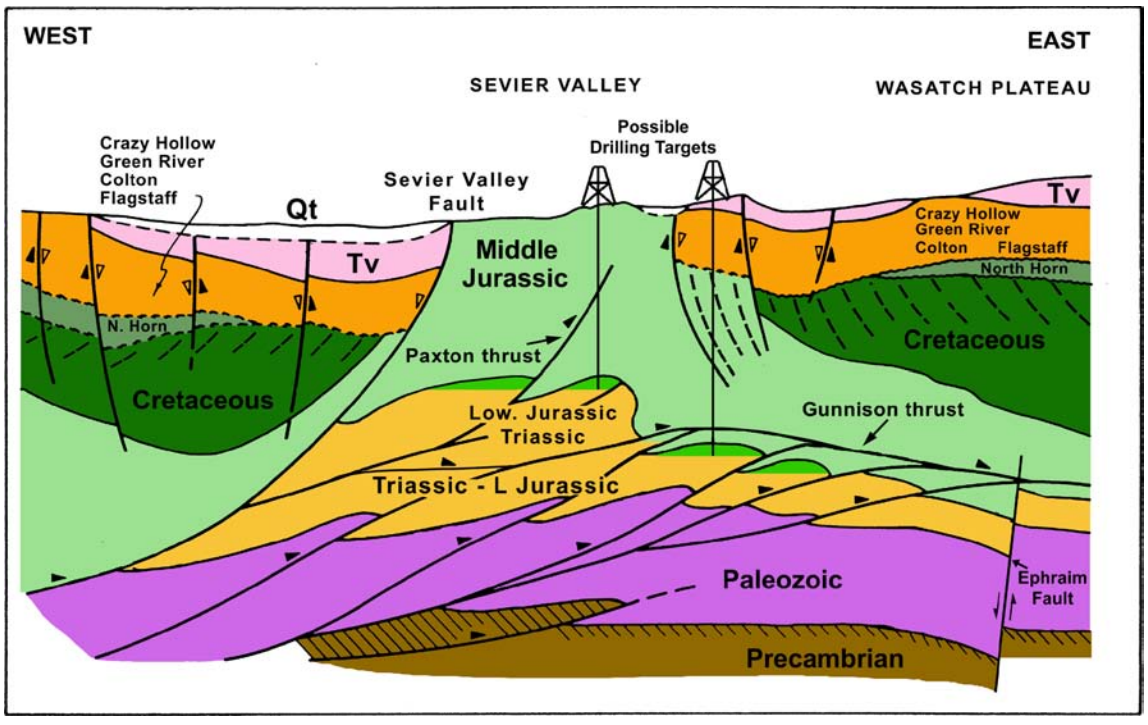


Figure 2-8. Schematic east-west structural cross section through Sevier Valley, Utah (line of section shown on figure 1-3B), just north of the 2004 Covenant field discovery (Jurassic Navajo Sandstone), showing potential Lower Jurassic exploratory drilling targets in thrust imbricates, fault-propagation folds, and duplexes above and below the Gunnison thrust. Note the presence of the basement-involved Ephraim fault in relationship to the duplex system. Modified from Villien and Kligfield (1986).

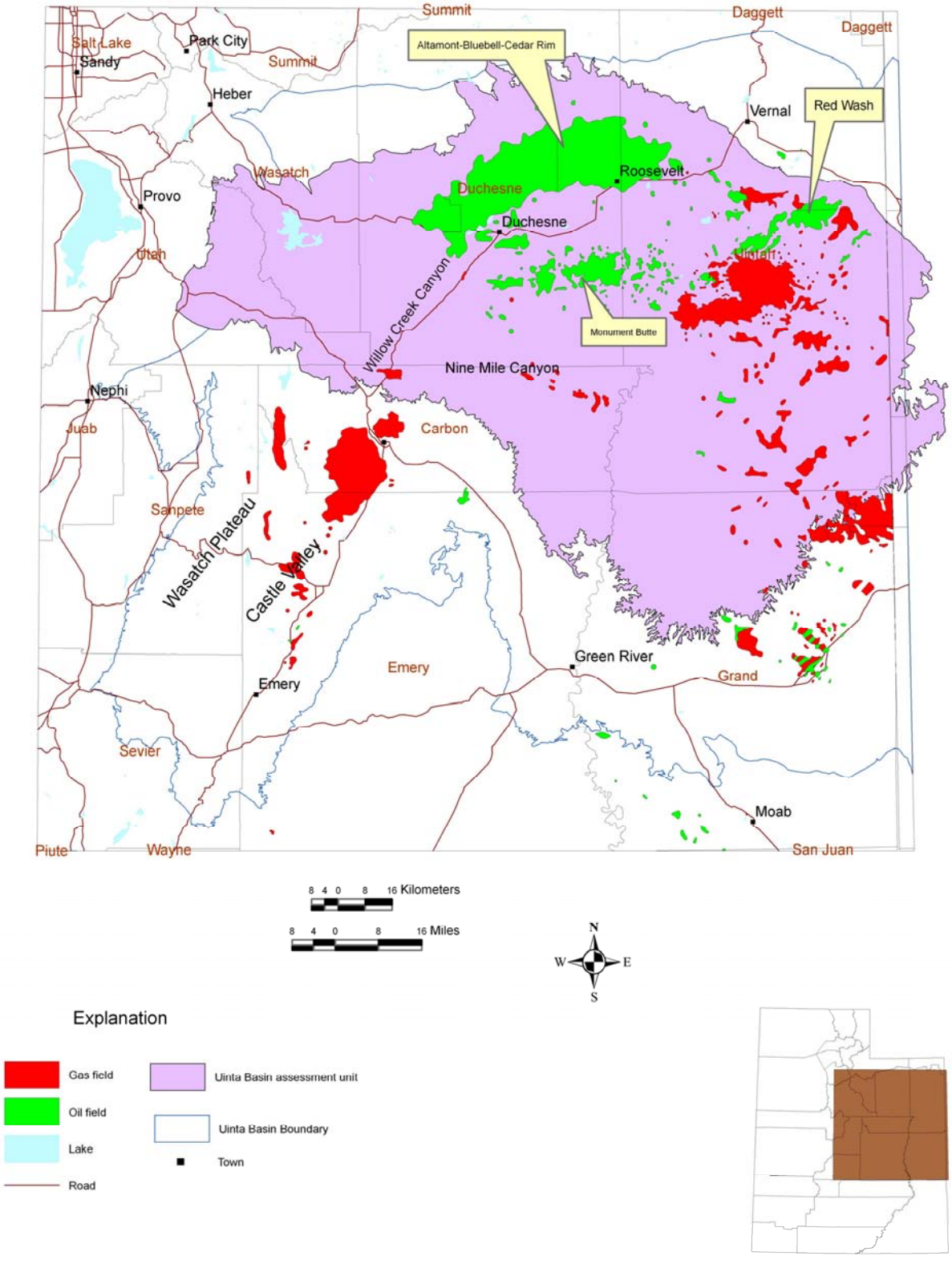


Figure 2-9. Map showing the location of the Uinta Basin and Uinta Basin assessment unit (from Dubiel, 2003) and some of the major oil and gas fields.

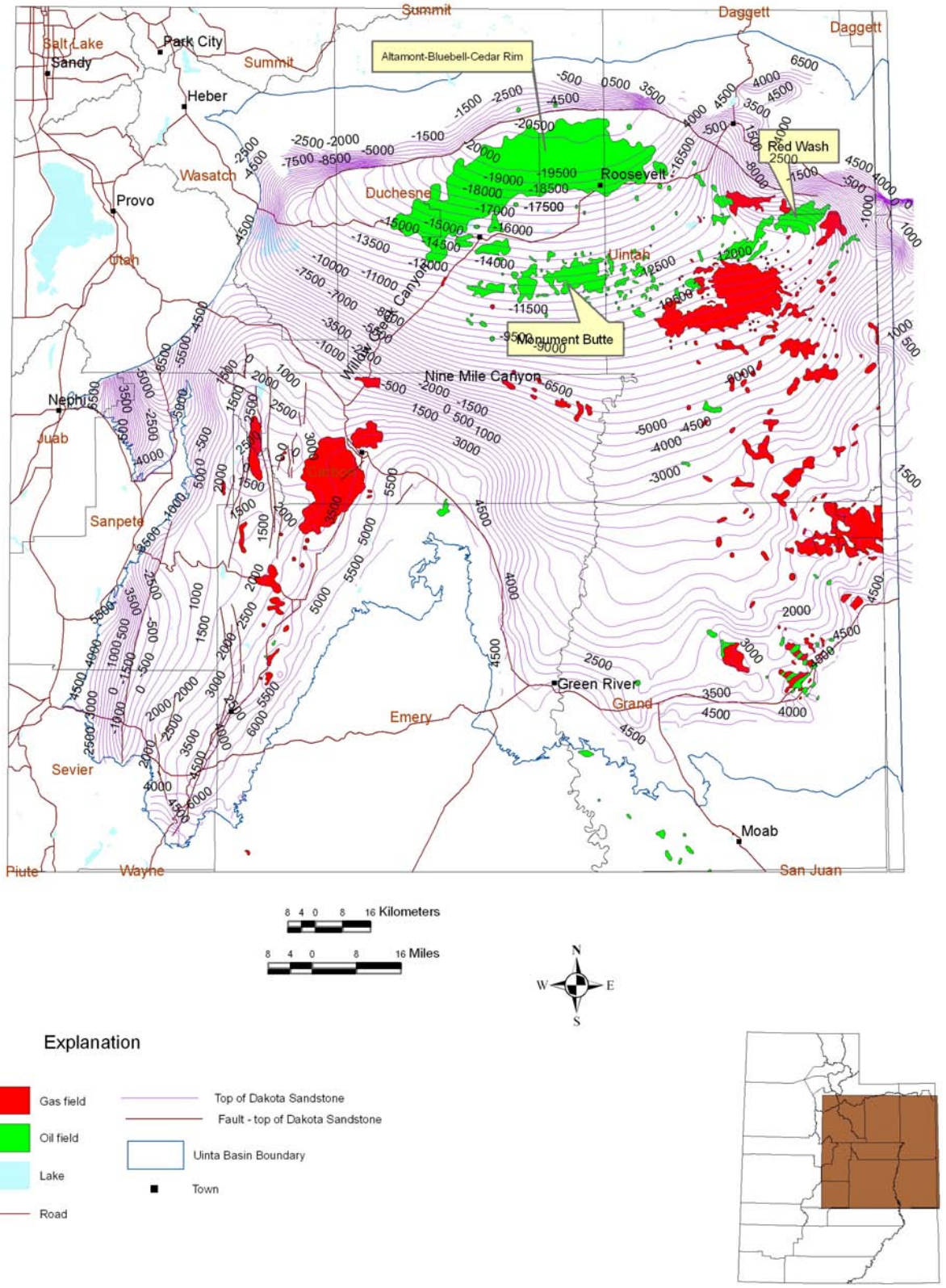


Figure 2-10. Structure contour map on top of the Cretaceous Dakota Sandstone, Uinta Basin. Contour interval is 500 feet, datum sea-level elevation. Contours from Roberts (2003).

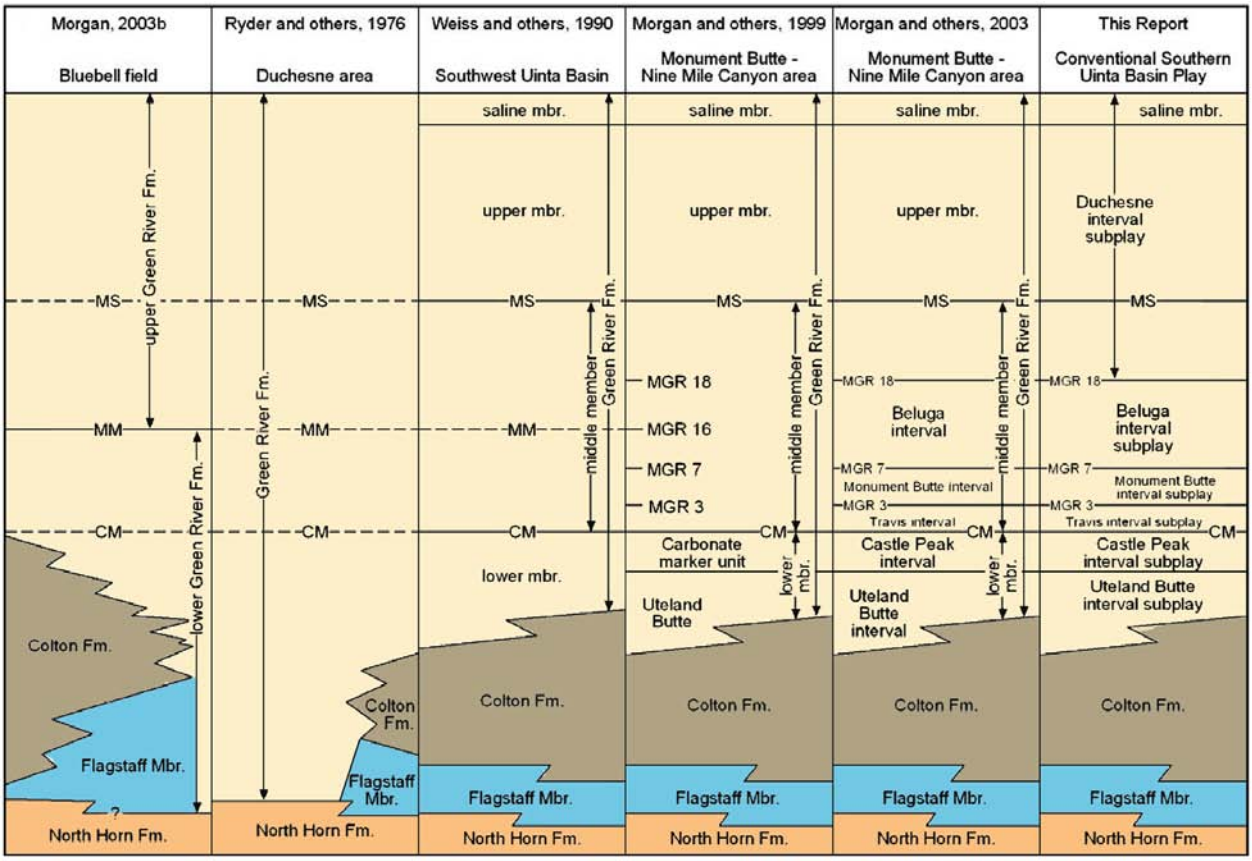


Figure 2-11. Generalized Uinta Basin nomenclature chart used in this report for the Green River through North Horn Formations. MS = Mahogany Shale, MM = middle marker, CM = carbonate marker, and MGR = middle Green River.

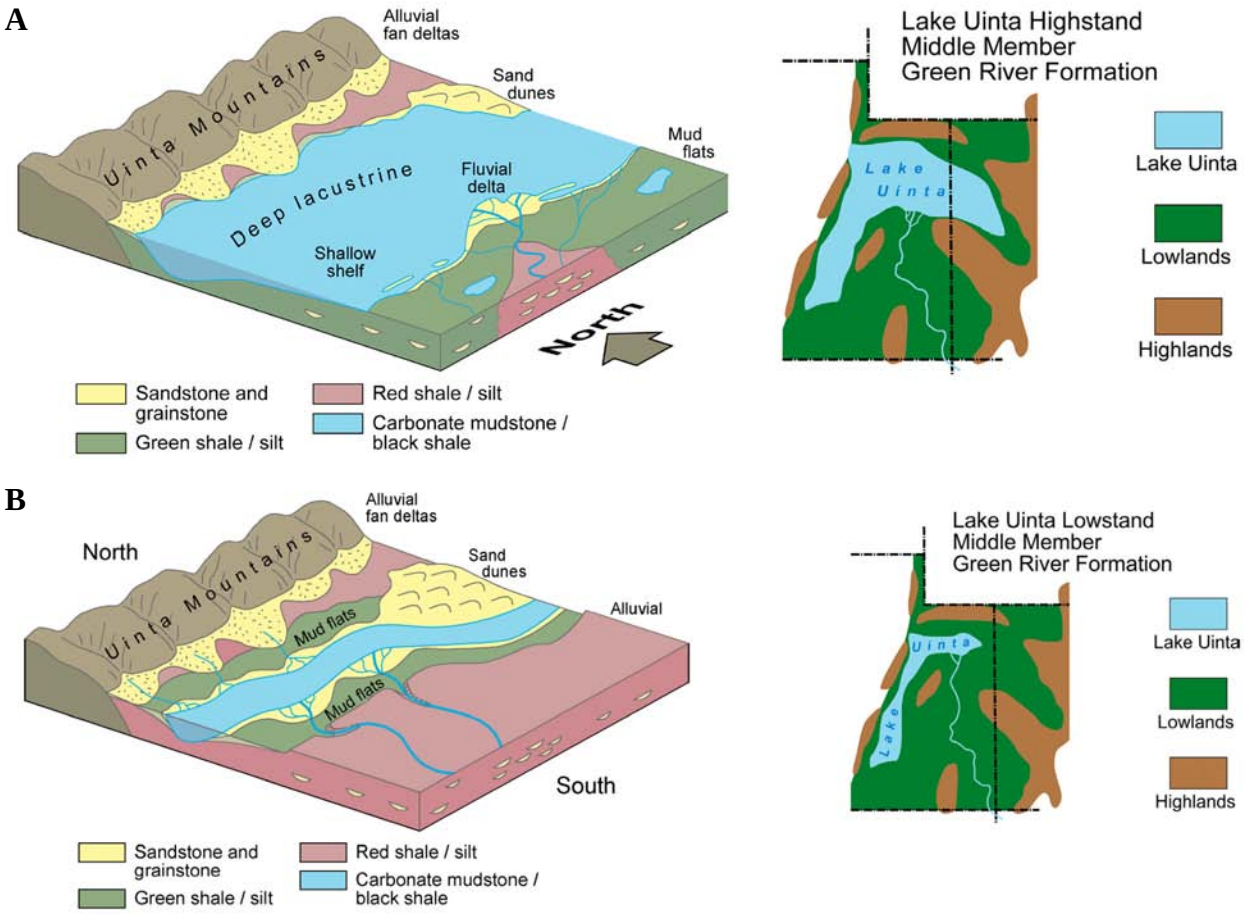


Figure 2-12. Diagrams showing the generalized depositional setting for Lake Uinta during high-lake levels (A) and low-lake levels (B). The Uinta Mountains were the source for the sediments in the northern portion of the lake while sediments in the southern portion of the lake were sourced from the much larger Four Corners area. Morgan and others, 2003.

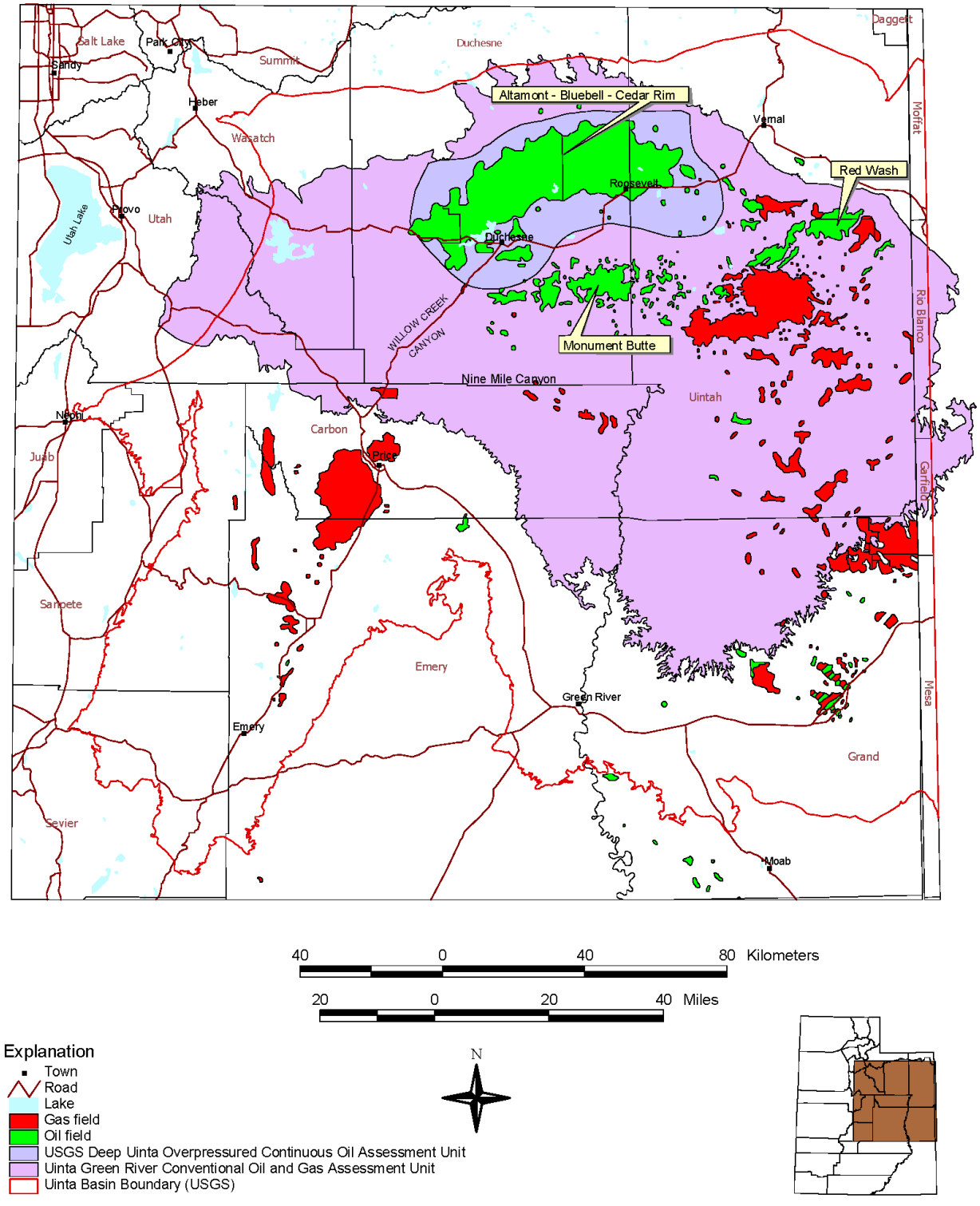


Figure 2-13. Map showing the USGS Deep Uinta Overpressured Continuous Oil Assessment Unit and the Uinta Green River Conventional Oil and Gas Assessment Unit of Dubiel (2003).

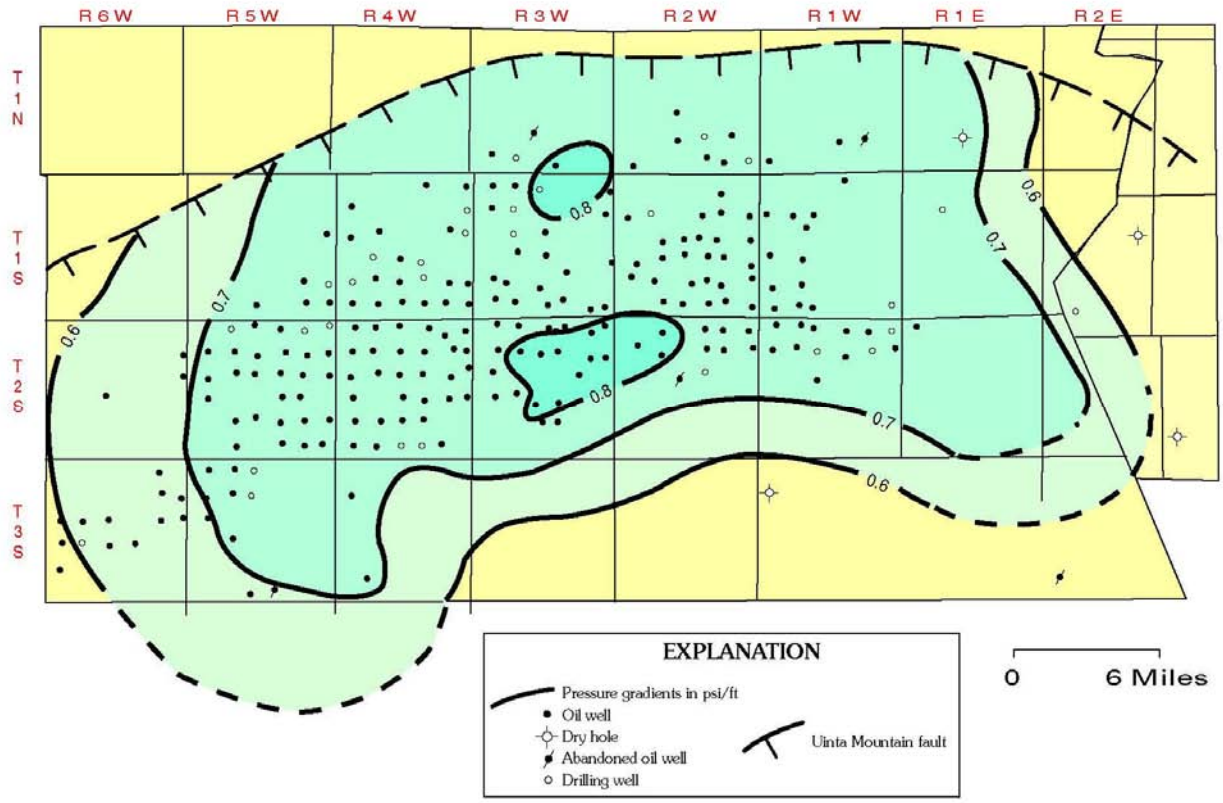


Figure 2-14. Distribution of wells and contours of pressure-gradient data in the Altamont – Bluebell field area from Dubiel (2003).

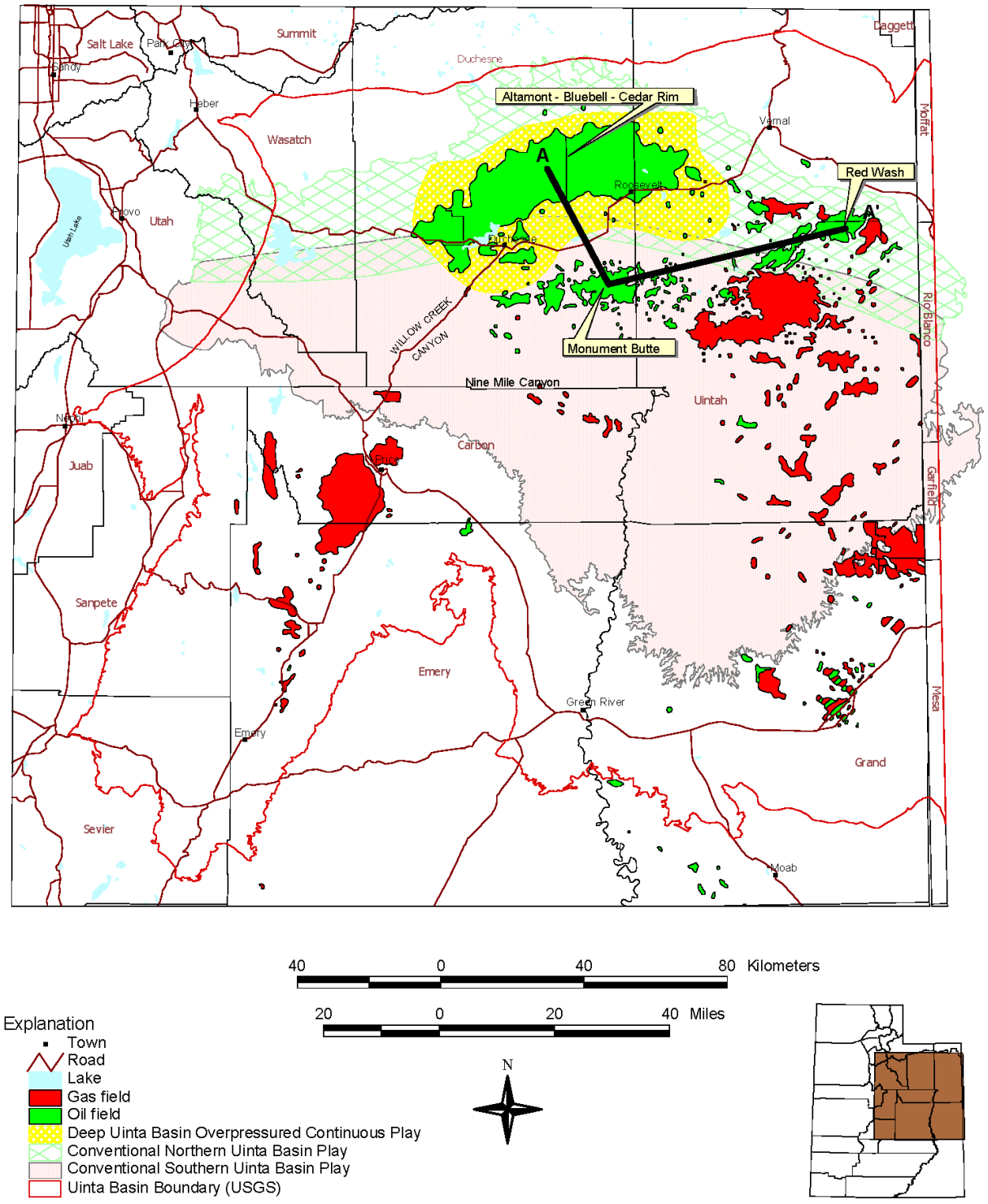


Figure 2-15. Map showing the Deep Uinta Basin Overpressured Continuous play which underlies the Conventional Northern and Conventional Southern Uinta Basin plays; these plays overlap. Cross section A-A' shown on figure 2-16.

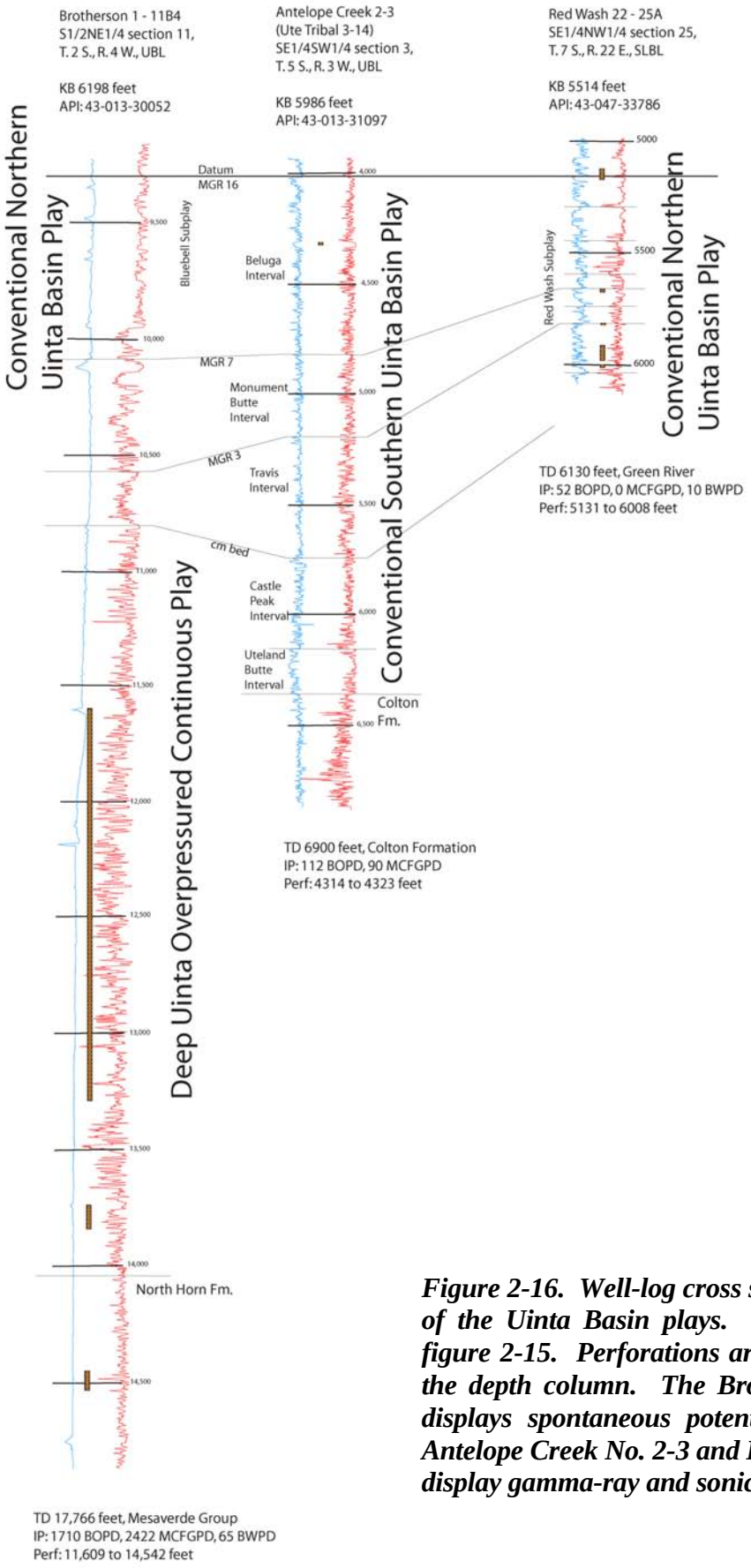


Figure 2-16. Well-log cross section showing correlation of the Uinta Basin plays. Line of section shown on figure 2-15. Perforations are shown as orange bars in the depth column. The Brotherson No. 1-11 B4 well displays spontaneous potential and sonic logs. The Antelope Creek No. 2-3 and Red Wash No. 22-25A wells display gamma-ray and sonic logs.

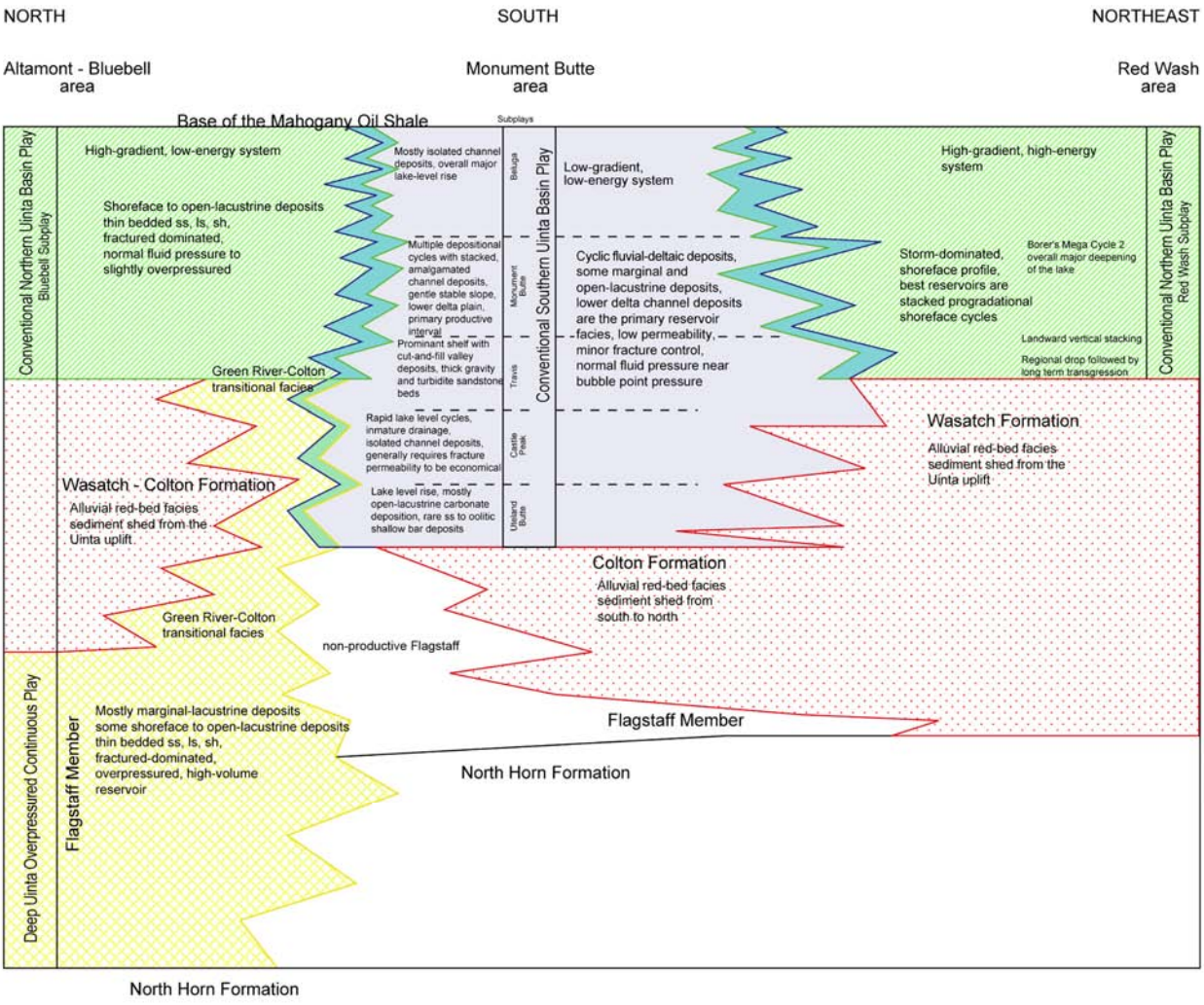


Figure 2-17. Diagrammatic correlation of the Green River plays in Uinta Basin. Sediment source and depositional energy systems resulted in varying reservoir characteristics in each of the plays and subplays.

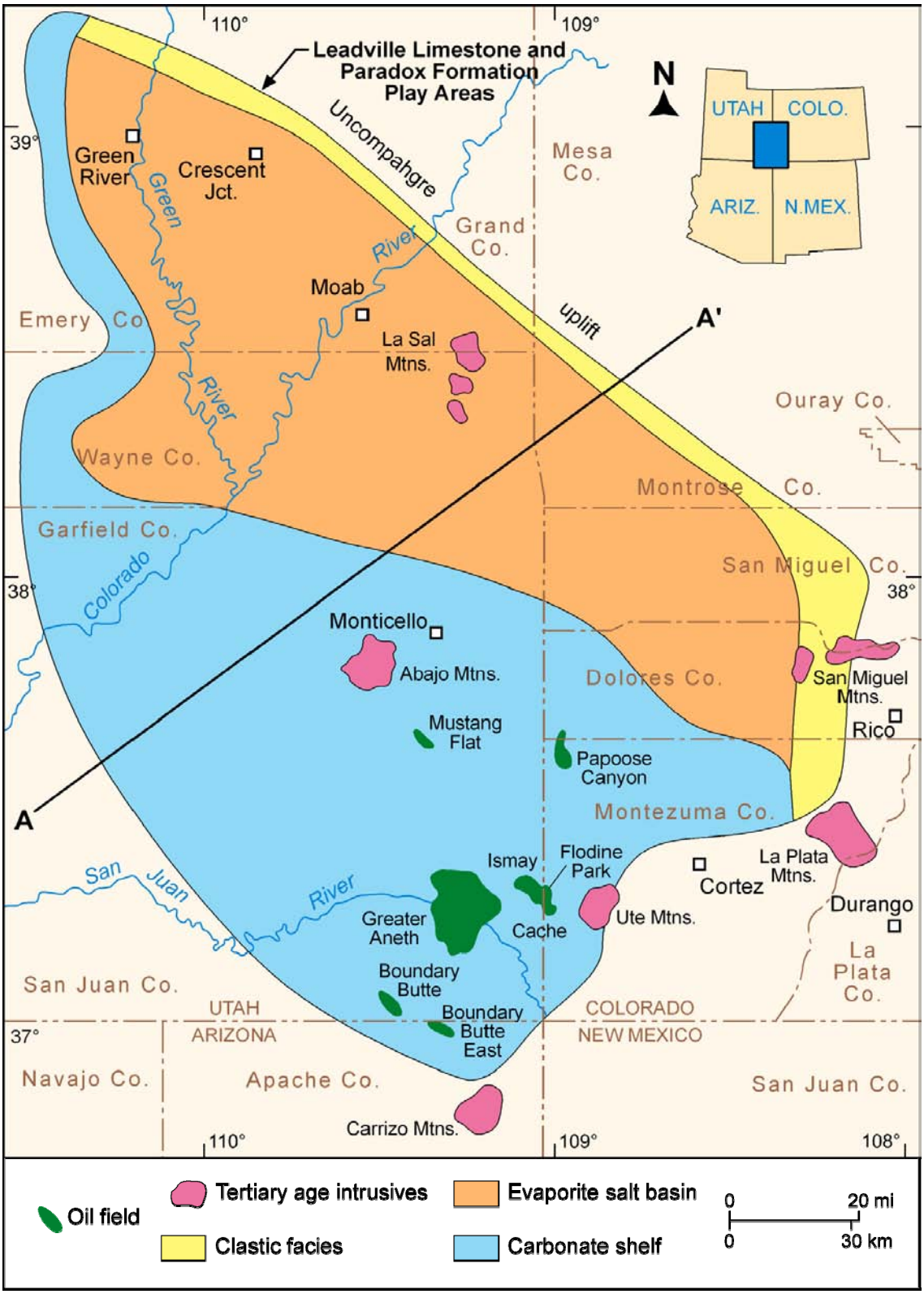


Figure 2-18. Generalized map of Paradox Formation facies with clastic wedge, evaporite salt basin, and carbonate shelf (modified from Wilson, 1975). Cross section A-A' shown on figure 2-19.

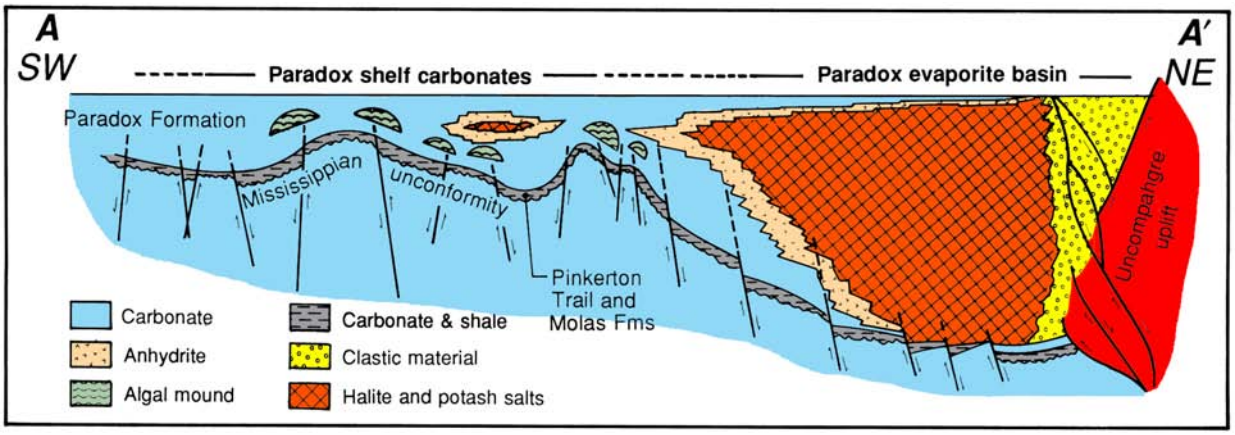


Figure 2-19. Generalized cross section across the Paradox Basin with gross facies relations between Middle Pennsylvanian shelf carbonates, restricted basin evaporites, and coarse clastics proximal to the Uncompahgre uplift (modified from Baars and Stevenson, 1981). Maximum extent of anhydrite beds in the Paradox Formation that define the basin is not shown. Location of cross section shown on figure 2-18.

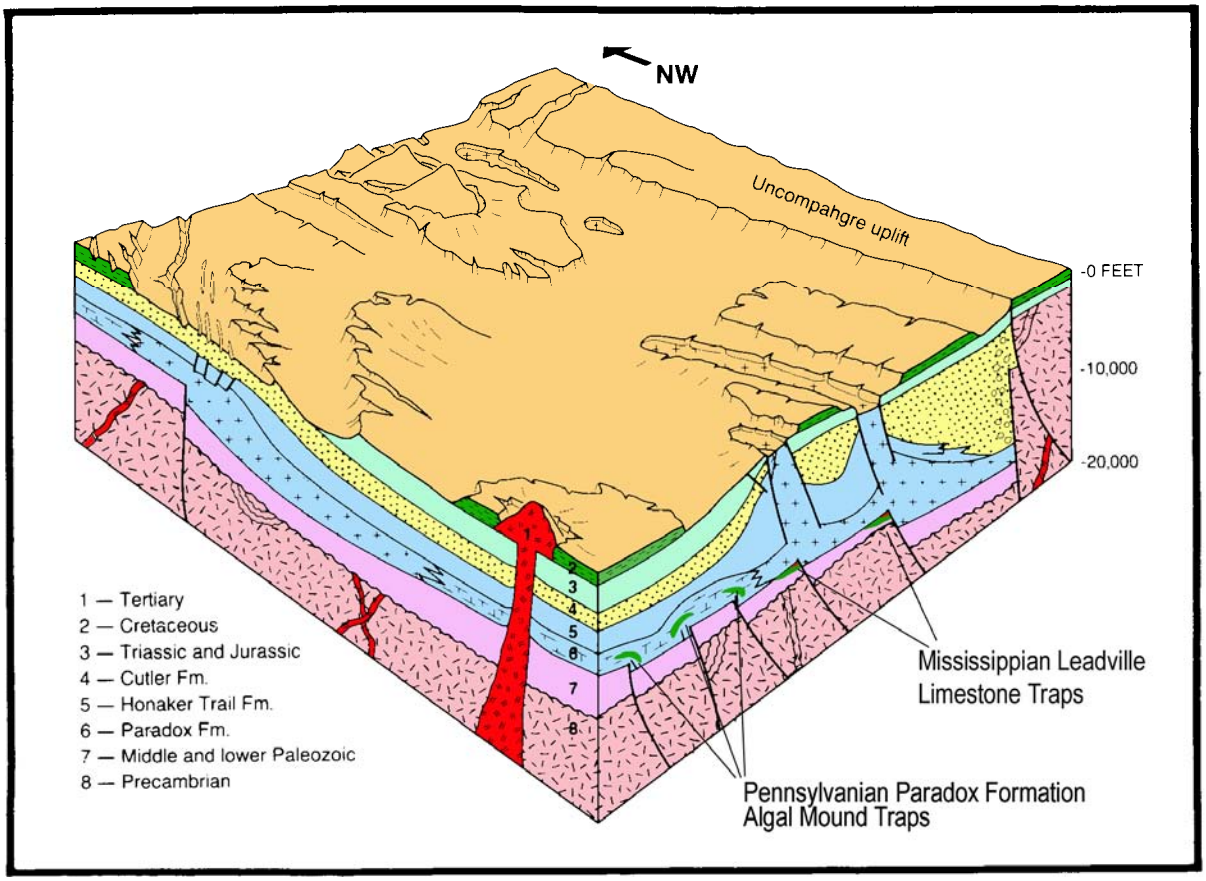


Figure 2-20. Schematic block diagram of the Paradox Basin displaying basement-involved structural trapping mechanisms for the Leadville Limestone fields and carbonate buildups for Paradox Formation fields (modified from Petroleum Information, 1984a; original drawing by J.A. Fallin).

PLAY DESCRIPTIONS

CHAPTER 3
JURASSIC NUGGET SANDSTONE THRUST BELT PLAY

Thomas C. Chidsey, Jr.,
Utah Geological Survey

Introduction

The most prolific oil and gas play confined to the hanging wall of the Absaroka thrust system is the Jurassic Nugget Sandstone thrust belt play (figure 3-1). The Nugget has produced over 288 million barrels (46 million m^3) of oil and 5.1 trillion cubic feet of gas (TCFG [145 billion m^3]); however, much of the gas included in the production figures is cycled gas, including nitrogen, for pressure maintenance (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008). Pineview field, Summit County, Utah, was the first to produce oil and gas from the Nugget in 1975 (Conner and Covlin, 1977; Petroleum Information, 1981) and led the way for additional discoveries over the next eight years. There are currently 13 Nugget fields, with eight entirely in Wyoming, four entirely in Utah, and one (Anschutz Ranch East) in both Utah and Wyoming. Geologic data for individual fields in the play are summarized in table 3-1.

The play outline represents the maximum extent of petroleum potential in the geographical area as defined by producing reservoirs, hydrocarbon shows, and untested hypotheses. The attractiveness of the Nugget Sandstone thrust belt play (and other thrust belt plays) to the petroleum industry depends on the likelihood of successful development, reserve potential, pipeline access, drilling costs, oil and gas prices, and environmental concerns. When evaluating these criteria, certain aspects of the Nugget play may meet the exploration guidelines of major oil companies while other aspects meet the development guidelines of small, independent companies.

Prospective drilling targets in the Nugget Sandstone thrust belt play are delineated using high-quality two-dimensional (2-D) and three-dimensional (3-D) seismic data, 2-D and 3-D forward modeling/visualization tools, well control, dipmeter information, high-quality surface geologic maps, and detailed analyses of structural geometry (Chidsey, 1999; Meneses-Rocha and Yurewicz, 1999). Incremental restoration of balanced cross sections is one of the best methods to assess trap geometry (Meneses-Rocha and Yurewicz, 1999). Several techniques can be used to determine the timing of structural development, petroleum migration, and entrapment, and to decipher fill and spill histories. These techniques include illite age analysis, apatite fission track analysis, and use of fluid inclusions (Meneses-Rocha and Yurewicz, 1999).

The Jurassic Nugget Sandstone thrust belt play is in the southwest Wyoming and northern Utah thrust belt (figure 3-1). The play area is bounded by truncations of the Nugget against the leading edge of the Absaroka thrust on the east, the Crawford thrust on the west, the North Flank fault of the Uinta uplift on the south, and the Little Muddy Creek transverse ramp on the north where the Nugget is exposed (figures 3-1 and 3-2). The Nugget Sandstone thrust belt play is productive along three principal anticlinal trends, and thus divided into three subplays (figure 3-2): (1) Absaroka thrust – Mesozoic-cored shallow structures, (2) Absaroka thrust – Mesozoic-cored deep structures, and (3) Absaroka thrust – Paleozoic-cored shallow structures (Lamerson, 1982). Each subplay has its own unique structural characteristics, average depth, and type and nature of petroleum. Each requires different engineering and completion

techniques. Depths to individual reservoirs are related to their position with respect to (1) the northeast-trending leading edge of the Absaroka thrust and associated imbricate thrusts (fields shallower to the west), and (2) two east-trending transverse ramps (fields deeper in the center, shallower to the north and south). Nugget thickness, lithology, lithofacies, reservoir properties, and diagenetic effects are generally the same for all three subplays.

Depositional Environment

In Early Jurassic time, Utah had an arid climate and lay 15° north of the equator (Hintze, 1993). The Nugget/Navajo Sandstone and age-equivalent rocks were deposited in an extensive dune field (eolian environment) which extended from Wyoming to Arizona (figure 3-3), and are comparable to the present Sahara in North Africa or the Alashan area of the Gobi in northern China. Navajo dunes were large to small, straight-crested to sinuous, coalescing, transverse barchanoid ridges (Picard, 1975). Regional analyses of the mean dip of dune foreset beds indicate paleocurrent and paleowind directions were dominantly from the north and northwest (figure 3-3) (Kocurek and Dott, 1983).

An oasis is a vegetated area in desert regions where springs or lakes are present for relatively long periods of time because the water table is close to the surface. Some Navajo interdunes were erosional (deflation) areas associated with running water, such as a wadi or desert wash. A wadi is a usually dry streambed or channel in a desert region. Low-relief, eolian sand sheets with poor drainage were also common (Lindquist, 1988).

Stratigraphy and Thickness

The Nugget Sandstone is typically 1100 feet (340 m) thick in the play area (Hintze, 1993) and has a characteristic geophysical log response (figure 3-4). Lindquist (1988) identified lower, middle, and upper units in the Nugget from core and geophysical log analysis of wells in Anschutz Ranch East field (figures 3-1 and 3-5). Each unit has a subtle but distinct characteristic geophysical log response.

The Nugget Sandstone is overlain by the Jurassic Twin Creek Limestone and underlain by the Triassic Ankareh Formation (figure 3-4). Average depth to the Nugget for all the thrust belt fields is 10,633 feet (3240 m).

Lithology and Fracturing

The lower Nugget Sandstone is composed of (1) a basal, thin-bedded unit about 140 feet (47 m) thick, characterized by horizontal stratification and ripple marks, and (2) an overlying 220-foot-thick (67 m) section dominated by climbing ripple laminae and small-scale cross-beds (Picard, 1975; Lindquist, 1988). The middle and upper units consist of a cyclic dune/interdune sequence (the principal petroleum-bearing section) more than 740 feet (250 m) thick, characterized by cross-stratification (figure 3-6). The middle unit is dominated by large-scale, planar or wedge-planar cross-beds (up to 35º) (Conner and Covlin, 1977), and is about 390 feet thick (130 m). The upper unit is dominated by wind ripples and small-scale cross-beds, and is about 350 feet thick (115 m). The boundary between the lower and middle units is transitional, whereas between the middle and upper units it is abrupt (figure 3-5) (Lindquist, 1988).

The dune/interdune sequence generally consists of fine- to coarse-grained, subangular to subrounded sand or silt grains cemented by calcite (Picard, 1975). Dune deposits consist almost entirely of sandstone, whereas interdune deposits consist of both sandstone and siltstone with some carbonate and evaporite lithologies. Dune lithofacies from the brink to the toe of the dune slipface consist of (1) thin, graded, tabular grainfall laminae (rarely preserved), (2) thick, subgraded avalanche laminae, and (3) thin, tightly packed, reworked ripple strata at the dune toe (Lindquist, 1983). Interdune lithofacies consist of fine-grained, thin, low-angle to horizontal laminae with zones of bioturbation (Lindquist, 1983).

Framework and matrix grains in sandstone (>1/16 mm and <1/16 mm, respectively) and siltstone (1/16 to 1/256 mm and <1/256 mm, respectively) are commonly composed of more than 90% quartz (usually frosted) with varying amounts of K-feldspar, plagioclase, and rock fragments (figure 3-7A). The typical sandstone contains 11% authigenic cement and 2% matrix grains; the typical siltstone contains 18% authigenic cement and 11% matrix grains (figure 3-7B) (Picard, 1975).

Fractures in the Nugget Sandstone consist of two types: (1) early, gouge-filled, silica cemented, impermeable fractures (figure 3-8), and (2) later, typically open (little gouge or cement), permeable fractures (Conner and Covlin, 1977). The later fractures are related to fault-propagation folding during the Sevier orogeny after deep burial (Royce and others, 1975; Conner and Covlin, 1977; Dixon, 1982; Lamerson, 1982).

Hydrocarbon Source and Seals

Hydrocarbons in Nugget Sandstone reservoirs were generated from subthrust Cretaceous source rocks (Warner, 1982). These include organic-rich units in the Bear River, Aspen (Mowry equivalent [Nixon, 1973]), and Frontier Formations. The source rocks began to mature after being overridden by thrust plates. Hydrocarbons were then generated, expelled, and subsequently migrated, primarily along fault planes, into overlying traps during the last 55 million years (Warner, 1982). Many structures in the hanging wall have juxtaposed the Nugget directly over these source rocks. Fracture systems developed along thrust imbrications may have provided secondary migration routes (Lamerson, 1982).

Burtner and Warner (1984) evaluated the hydrocarbon generation from the Mowry Shale in the Green River Basin (overridden in the western part by the thrust belt) and other northern Rocky Mountain basins. Their study showed that the Mowry ranges from 0.7 to 4.1 weight percent total organic content (TOC) and contains a mixture of type II (marine) and type III (terrestrial) organic matter. In the Green River Basin, Mowry areas having T_{max} values (the temperature during pyrolysis of peak hydrocarbon generation) greater than 435ºC coincide with areas anomalously low in TOC, indicating that hydrocarbons and CO_2 were generated and subsequently migrated out of the source beds (Burtner and Warner, 1984).

The seals for the Nugget producing zones are the overlying argillaceous and gypsiferous beds of the Gypsum Spring Member of the Jurassic Twin Creek Limestone, or a 10- to 60-foot-thick (3-30 m), low-permeability zone on top of the Nugget Sandstone. Hydrocarbons in the Nugget/Twin Creek system are further sealed by salt beds within the overlying Jurassic Preuss Formation.

Structure and Trapping Mechanisms

Absaroka Thrust – Mesozoic-Cored Shallow Structures Subplay

The Nugget Sandstone Absaroka thrust – Mesozoic-cored shallow structures subplay is located in the western part of Summit County, Utah and Uinta County, Wyoming (figure 3-9). The subplay represents a linear, hanging-wall, Mesozoic-cored, ramp anticline parallel to the leading edge of the Absaroka thrust (figure 3-10). Average depth to the Nugget in the shallow subplay is 9300 feet (3100 m). Two broad structural highs (culminations), separated by a structural low (depression), are present along the ramp anticline (Lamerson, 1982; Chidsey, 1993) where individual traps are formed by closure on subsidiary anticlines (figure 3-2). These culminations may be due to proximity to transverse ramp features. The north culmination is related to the Little Muddy Creek transverse ramp along the north border of the Nugget play area and contains Painter Reservoir (figure 3-11), Clear Creek, and Ryckman Creek fields (figures 3-1 and 3-9). The south culmination is related to a transverse ramp associated with the Uinta uplift along the south border of the play area and contains Pineview and Lodgepole fields (figures 3-1 and 3-9). The eastern boundary of the subplay is defined by the truncation of the Nugget against the leading edge of the Absaroka thrust. The western boundary is defined by a branch line representing the intersection of the thrust planes of the Absaroka thrust and a large imbricate thrust (Boyer and Elliott, 1982). The southern part of the Absaroka thrust plate trends southwest toward the Wasatch Range where the Nugget Sandstone play area terminates. The subplay is mapped as two 5-mile-wide (8 km) bands (figure 3-9).

Potential petroleum-trapping mechanisms in the Nugget Sandstone Absaroka thrust - Mesozoic-cored shallow structures subplay consist of long, narrow, doubly plunging anticlines (figure 3-12) (Royce and others, 1975; Conner and Covlin, 1977; Dixon, 1982; Lamerson, 1982). These anticlines are asymmetric, overturned to the east, and often develop en echelon structures along the leading edge of the Absaroka thrust because of variations in the competence and thickness of the stratigraphic sequence (West and Lewis, 1982). Pineview field, Summit County, Utah, exemplifies the traps in the subplay (figures 3-9, 3-12, and 3-13). The Nugget reservoir covers approximately 1280 acres (572 ha) and has more than 1000 feet (300 m) of structural closure.

Absaroka Thrust – Mesozoic-Cored Deep Structures Subplay

The Nugget Sandstone Absaroka thrust – Mesozoic-cored deep structures subplay is also located in the western part of Summit County, Utah and Uinta County, Wyoming (figure 3-14). The subplay represents a linear, Mesozoic-cored ramp anticline developed in the structural low (depression) between the north and south culminations of the shallow structures subplay and along the truncation of the Nugget against the Absaroka thrust (figures 3-2 and 3-10) (Lamerson, 1982). The Mesozoic-cored shallow and deep structures subplays are also separated by imbricate thrusts along strike, and backlimb thrust faults are present locally (figures 3-10 and 3-11). Average depth to the Nugget in the deep subplay is 12,810 feet (3900 m). Discrete anticlinal closures form Pineview North, Anschutz Ranch East, Bessie Bottom, Chicken Creek, Glasscock Hollow, and Painter Reservoir East fields (figures 3-1 and 3-14). The subplay extends north as a 5-mile-wide (8 km) band into Uinta County, Wyoming (figure 3-14).

Similar to the Absaroka thrust – Mesozoic-cored shallow structures subplay, potential

petroleum-trapping mechanisms in the Nugget Sandstone Absaroka thrust – Mesozoic-cored deep structures subplay also consist of long, narrow, doubly plunging anticlines (figures 3-15 and 3-16) (Royce and others, 1975; Conner and Covlin, 1977; Dixon, 1982; Lamerson, 1982). These anticlines are asymmetric and overturned to the east as well. Splay faults and salt near the anticlinal axes are common, complicating drilling operations and compartmentalizing productive zones (figure 3-16).

Anschutz Ranch East field is an excellent example of Mesozoic-cored deep structures (figure 3-1). It is the largest field in the subplay in terms of hydrocarbon column thickness, cumulative production and reserves, and areal extent (figures 3-15 and 3-16). The reservoir covers approximately 4620 acres (1870 ha) and is divided into two structural lobes. The larger west lobe is a narrow, elongate anticline overturned to the east (Lelek, 1982). Average depth to the Nugget Sandstone in the west lobe is 12,900 feet (4300 m) with more than 2100 feet (700) of closure. When the west lobe reservoir was discovered in 1979, the hydrocarbon column was near the spill point. The smaller east lobe has the same general configuration as the west lobe, and is separated from it by an overturned syncline (Lelek, 1982). Average depth to the Nugget Sandstone in the east lobe is 14,325 feet (4775 m), and it has more than 1000 feet (330 m) of closure. When the east lobe reservoir was discovered in 1981, the hydrocarbon column was also near the spill point (Petroleum Information, 1984b).

Absaroka Thrust – Paleozoic-Cored Shallow Structures Subplay

The Nugget Sandstone Absaroka thrust – Paleozoic-cored shallow structures subplay is located immediately west of the Mesozoic-cored structures subplays (figure 3-17). The subplay represents a very continuous and linear, hanging-wall, Paleozoic-cored, ramp anticline parallel to the leading edge of the Absaroka thrust (figure 3-18). The eastern boundary of the subplay is defined by the truncation of the Nugget against a thrust splay. The western boundary is defined as the point at which the dips on the west flank of the ramp anticline begin to flatten out. The southern part of this ramp anticline trends southwest toward the Wasatch Range where the play area terminates. The play extends north as a 3-mile-wide (4.8 km) band through Summit County, Utah and into western Uinta County, Wyoming (figure 3-17).

Potential petroleum-trapping mechanisms in the Nugget Sandstone Absaroka thrust - Paleozoic-cored shallow structures subplay also consist of long, narrow, doubly plunging anticlines that trend north to northeast (figures 3-19 and 3-20) (Royce and others, 1975; Conner and Covlin, 1977; Petroleum Information, 1981; Dixon, 1982; Lamerson, 1982). These anticlines are also asymmetric and overturned to the east. There are just two fields in the Nugget Sandstone Absaroka thrust – Paleozoic-cored shallow structures subplay: Anschutz Ranch in Summit County, Utah, and Yellow Creek in Uinta County, Wyoming (figure 3-17). For example, Anschutz Ranch field consists of a large, elongate anticline with more than 7100 feet (2164 m) of structural closure involving Jurassic through Ordovician rocks; the reservoir covers approximately 2880 acres (1170 ha). However, hydrocarbons are trapped only on the very crest of the structure, as is the case at Yellow Creek field.

Reservoir Properties

The Nugget Sandstone has heterogeneous reservoir properties because of (1) cyclic dune/interdune lithofacies with better porosity and permeability that developed in certain dune

morphologies, (2) diagenetic effects, and (3) fracturing. The typical sandstone has an average porosity of 14%; the typical siltstone has an average porosity of 7% (figure 3-7B; Picard, 1975). They exhibit significant secondary porosity in the form of fracturing. Permeabilities in the Nugget range from 1 to more than 200 millidarcies (mD). The best permeability within Nugget dune deposits is along bounding surfaces (bedding planes), with preferred directions along the dip and strike of the individual slipfaces (cross-beds) (figure 3-21A; Lindquist, 1983). Porosity and permeability are greatest in thickly laminated avalanche deposits (Hunter, 1977; Schenk, 1981). Nugget interdunes, however, have significantly poorer reservoir characteristics than the dune 1ithofacies (figure 3-21B). In Painter Reservoir, for example, the average porosity and permeability is only 9.7% and 1.5 mD, respectively, in interdune lithofacies, but 13.6% and 16.5 mD in dune lithofacies (Tillman, 1989). The low-permeability interdune lithofacies is a potential barrier to flow (figure 3-21B). Identification and correlation of dune/interdune lithofacies in individual Nugget reservoirs are critical to understanding the effects on production rates and paths of petroleum movement. Natural fractures also affect permeability, and control hydrocarbon production and injection fluid pathways (Parra and Collier, 2000).

Diagenetic effects and fracturing have both reduced and enhanced the reservoir permeability of the Nugget Sandstone. Overgrowths of quartz and feldspar, authigenic clay mineralization (illite and chlorite), ferroan dolomitization, emplacement of asphaltenes, and the development of gouge and calcite-filled fractures locally have reduced reservoir permeability (Lindquist, 1983). Dissolution of silicate minerals and the development of open fractures have increased reservoir permeability (Lindquist, 1983).

Nugget net-pay thickness is variable, depending on fracturing, and ranges from 22 to 900 feet (7-300 m). The average Nugget reservoir temperature is 185ºF (85ºC). Water saturations range from 22 to 45%, and average resistivity (R_w) is 0.284 ohm-m at 68ºF (20ºC). Initial reservoir pressures average about 3900 psi (26,890 kPa). The reservoir drive mechanisms include pressure depletion, active water drive, and solution gas.

Reservoir data for individual fields in the Jurassic Nugget Sandstone thrust belt play are summarized in table 3-1. For details see Loucks (1975), Conner and Covlin (1977), Kelly and Hine (1977), Jones (1979), Moklestad (1979), Petroleum Information (1981, 1984b), Frank and Gavlin (1981), Frank and others (1982), Chase and others (1992a, 1992b), Holm (1992), Mullen (1992a, 1992b), Powers (1992), Benson (1993a), Cook and Dunleavy (1993), Chidsey (1993), and Lindquist and Ross (1993).

Oil and Gas Characteristics

In major reservoirs, the produced Nugget oil and retrograde condensate are rich, volatile crudes. The API gravity of the oil ranges from 43º to 48º; the gas-oil ratio ranges between 300 and 640 cubic feet/bbl. The API gravity of the condensate ranges from 47º to 63º; the gas-oil ratio ranges from 3800 and 7750 cubic feet/bbl. Oil colors vary from light to dark brown, and condensate can be clear to various shades of yellow, orange, and brown. In some cases, color can change with location or structural position within a single field. In Anschutz Ranch East field (figure 3-1), for example, the color of the condensate oil changes with the structural position of the producing wells. Condensate on the crest is pale yellow, turning darker shades (yellow through brown) with increasing depth (figure 3-22). The color change is likely the result of gravity segregation within the reservoir where condensate at the top of structure contains more dissolved gas than at the bottom. The viscosity of the crude oil is 2.18 centistokes (cst) at 104ºF

(40ºC); in Saybolt Universal Seconds (sus) the viscosity averages 33.2 sus at 104ºF (40ºC). The viscosity of the condensate averages 1.09 cst and 29.4 sus at 104ºF (40ºC). The pour point of the crude oil is 15ºF (9.4ºC). The average weight percent sulfur and nitrogen of produced Nugget hydrocarbon liquids are 0.04 and 0.004, respectively.

In the Mesozoic-cored shallow structures subplay, the three Wyoming fields on the northern culmination produce associated gas that is very uniform in composition: 74 to 80% methane, 11 to 15% ethane, 5 to 7% propane, 2% butane, 0.4% pentane, and 2% nitrogen (Frank and Gavlin, 1981). Heating values average 1252 British thermal units/cubic foot (Btu/ft^3). Pineview field on the south culmination produces associated gas that is significantly different in composition: 35% methane, 10% ethane, 9% propane, 8% butane, 4% pentane, 2% hexane, 31% heptanes (and higher hydrocarbon fractions), 0.6% nitrogen, and 0.7% carbon dioxide (Petroleum Information, 1984b). The heating value is 2964 Btu/ft^3. Fields on the Mesozoic-cored deep structures subplay produce nonassociated gas that is remarkably uniform in composition: 74 to 79% methane, 12 to 15% ethane, 5% propane, 2% butane, <1% pentane, and 2% nitrogen (Frank and Gavlin, 1981; Moore and Sigler, 1987). Heating values average 1216 Btu/ft^3. The Nugget reservoir in Anschutz Ranch field (figure 3-1) on the Paleozoic-cored shallow structures subplay produces nonassociated gas (with condensate) that is somewhat different in composition than gas produced on the Mesozoic-cored shallow and deep structures subplays. The gas contains 81% methane, 8% ethane, 3% propane, 1.5% butane, 0.6% pentane, and 6% nitrogen, making it a low-quality gas (Utah Geological Survey field files). The heating value is 1101 Btu/ft^3. Gas produced from the reservoirs in the Nugget Sandstone thrust belt play contains no hydrogen sulfide.

Production

Five fields in the Jurassic Nugget Sandstone Absaroka thrust – Mesozoic-cored shallow structures subplay have produced crude oil and associated gas. Pineview, Lodgepole, Painter Reservoir, Clear Creek, and Ryckman Creek fields (figure 3-1) have combined to produce 85 million bbls of oil (MMBO [14 MMCMO]) and 1.15 TCFG (32 BCMG) from the Nugget as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008) (table 3-1). There are currently 77 active producers and 58 abandoned Nugget producers in this subplay (table 3-1).

Six fields in the Jurassic Nugget Sandstone Absaroka thrust – Mesozoic-cored deep structures subplay have produced retrograde condensate and nonassociated gas. Pineview North, Anschutz Ranch East, Bessie Bottom, Chicken Creek, Glasscock Hollow, and East Painter Reservoir fields (figure 3-1) have combined to produce 202 million bbls of condensate (MMBC [32 MMCMC]) and 3.9 TCFG (111 BCMG) from the Nugget as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008) (table 3-1). There are currently 114 active producers and 15 abandoned producers in this subplay (table 3-1).

Two fields in the Jurassic Nugget Sandstone Absaroka thrust – Paleozoic-cored shallow structures subplay have produced nonassociated gas and condensate. Anschutz Ranch and Yellow Creek fields (figure 3-1) have combined to produce 776,415 bbls of condensate (123,459 BC) and 43 billion cubic feet of gas (BCFG [1.2 BCMG) from the Nugget as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission,

2008) (table 3-1). There are currently two active and five abandoned Nugget producers in this subplay (table 3-1).

In 2007, the monthly production from the Nugget Sandstone averaged 172,463 bbls of oil (and condensate) (27,422 MCMO) and 9.5 BCFG (0.3 BCMG) (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008). Monthly production peaked in 1979, and has generally declined since then. However, in the 1990s, the intensely fractured and depositionally heterogeneous zones of the Nugget in Lodgepole, Pineview, and Painter Reservoir fields were successfully exploited using horizontal-drilling techniques. Lodgepole field was sub-commercial prior to the horizontal-drilling program.

Exploration Potential and Trends

Future exploration in the Nugget Sandstone thrust belt play could focus on more structurally complex and subtle, thrust-related traps that overlie organic-rich Cretaceous strata. Possible structural targets include complex traps formed by true duplexes, overlapping ramp anticlines, and hybrid duplexes (Mitra, 1986). In these structures, naturally fractured sandstone beds and the overlying seals of the Twin Creek Limestone are repeated many times. Other thrust-related structural traps include subtle fault-propagation folds formed by imbricate thrust faults or stacked imbricate faults. These traps may be developed along secondary fault-propagation folds, along backlimb thrust faults, or between imbricate splays on the forelimb of anticlines (Mitra, 1986, 1990). Nugget structures may be present beneath the leading edge of the Hogsback thrust and North Flank fault of the Uinta uplift (Chidsey, 1999). Minor irregularities along the Nugget truncation against major thrusts may also be the locations for untested structures, particularly in the Mesozoic-cored shallow and deep structures subplays on the Absaroka thrust system.

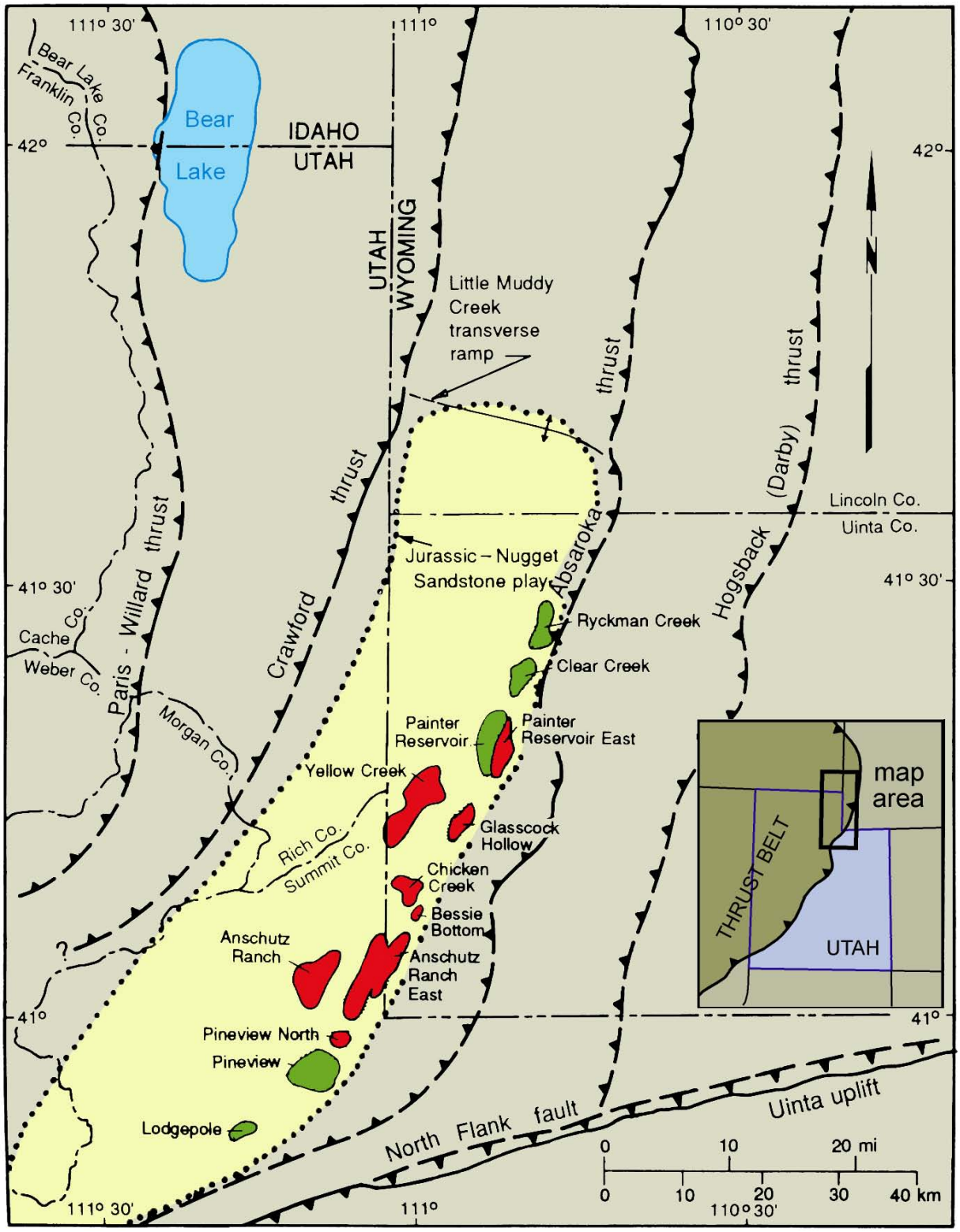


Figure 3-1. Location of reservoirs that produce oil (green) and gas and condensate (red) from the Jurassic Nugget Sandstone, Utah and Wyoming; major thrust faults are dashed where approximate (teeth indicate hanging wall). The Nugget Sandstone thrust belt play area is dotted. Modified from Chidsey (1993).

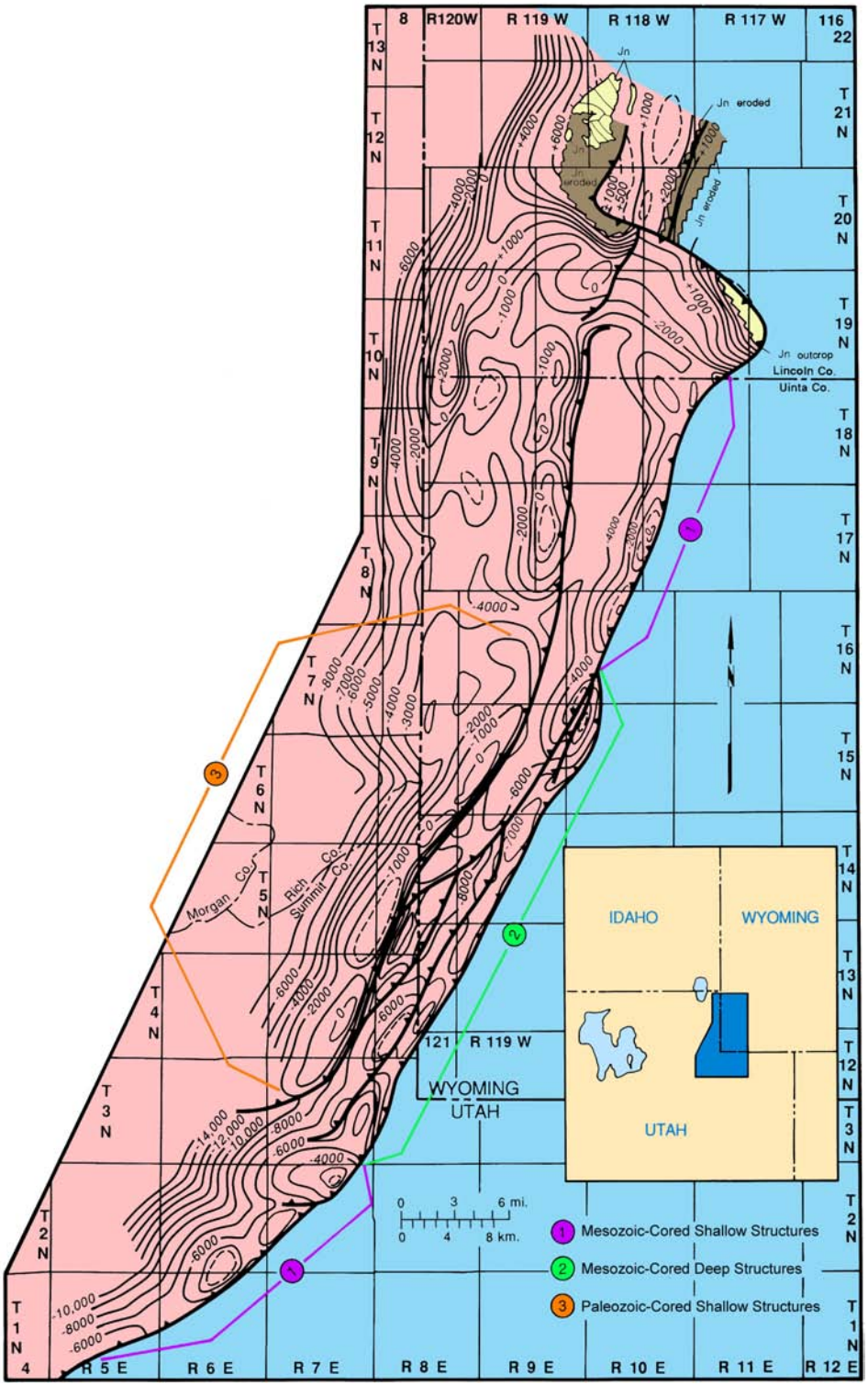


Figure 3-2. Generalized structure contour map of the top of the Jurassic Nugget Sandstone on the southern Absaroka thrust plate, Utah-Wyoming thrust belt. The three principal anticlinal trends, which define the subplays, are indicated based on their location with respect to the leading edge of the Absaroka thrust, the presence of imbricate thrusts which separate the trends, and the depth to the Nugget. Datum mean sea level, contour interval 1000 feet, dashed where approximate. Modified from Lamerson (1982).

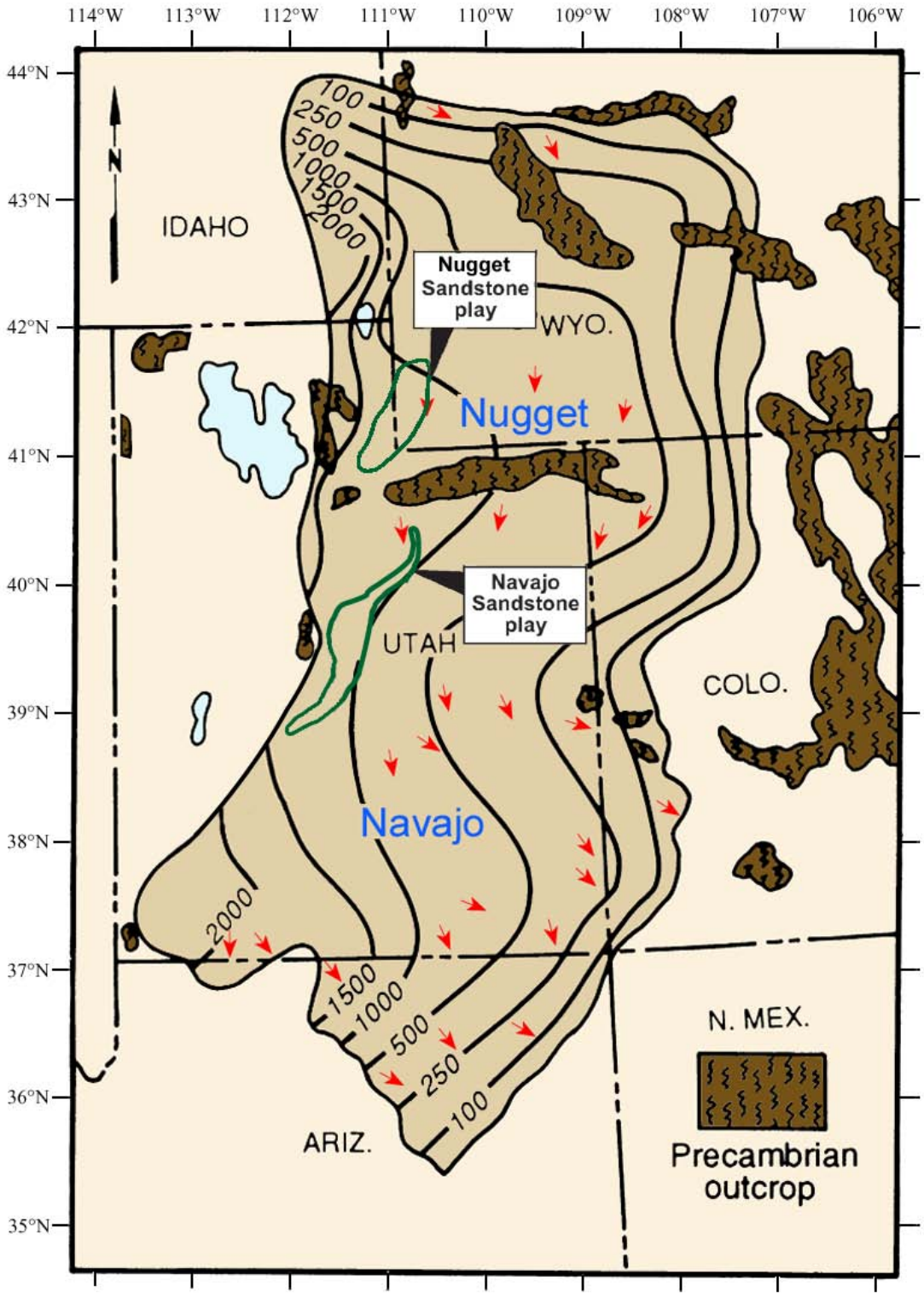


Figure 3-3. Regional isopach map of the Nugget/Navajo Sandstone based on measured sections and well data. Paleowind generally from the north and northwest is shown by arrows. Contours are in feet. Modified from Picard (1975); Kocurek and Dott (1983).

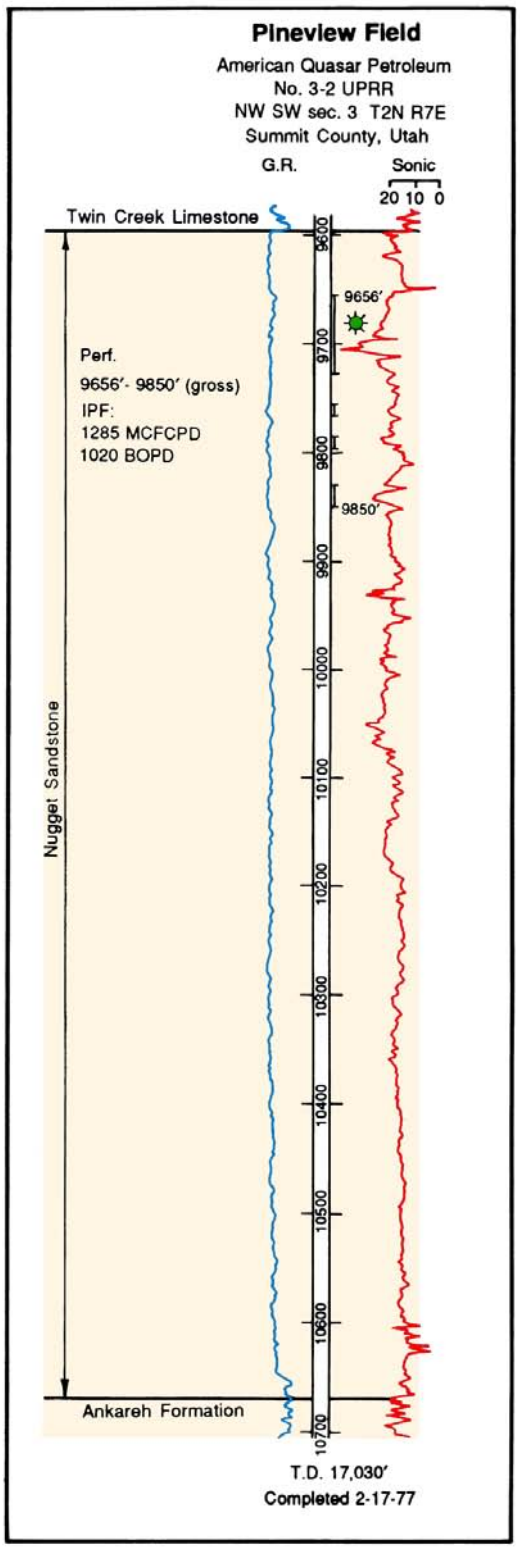


Figure 3-4. Typical gamma ray-sonic log of the Nugget Sandstone. Example from a development well in the Pineview field, Summit County, Utah. The vertical lines between depths of 9656 and 9850 feet on the log indicate producing (perforated) intervals.

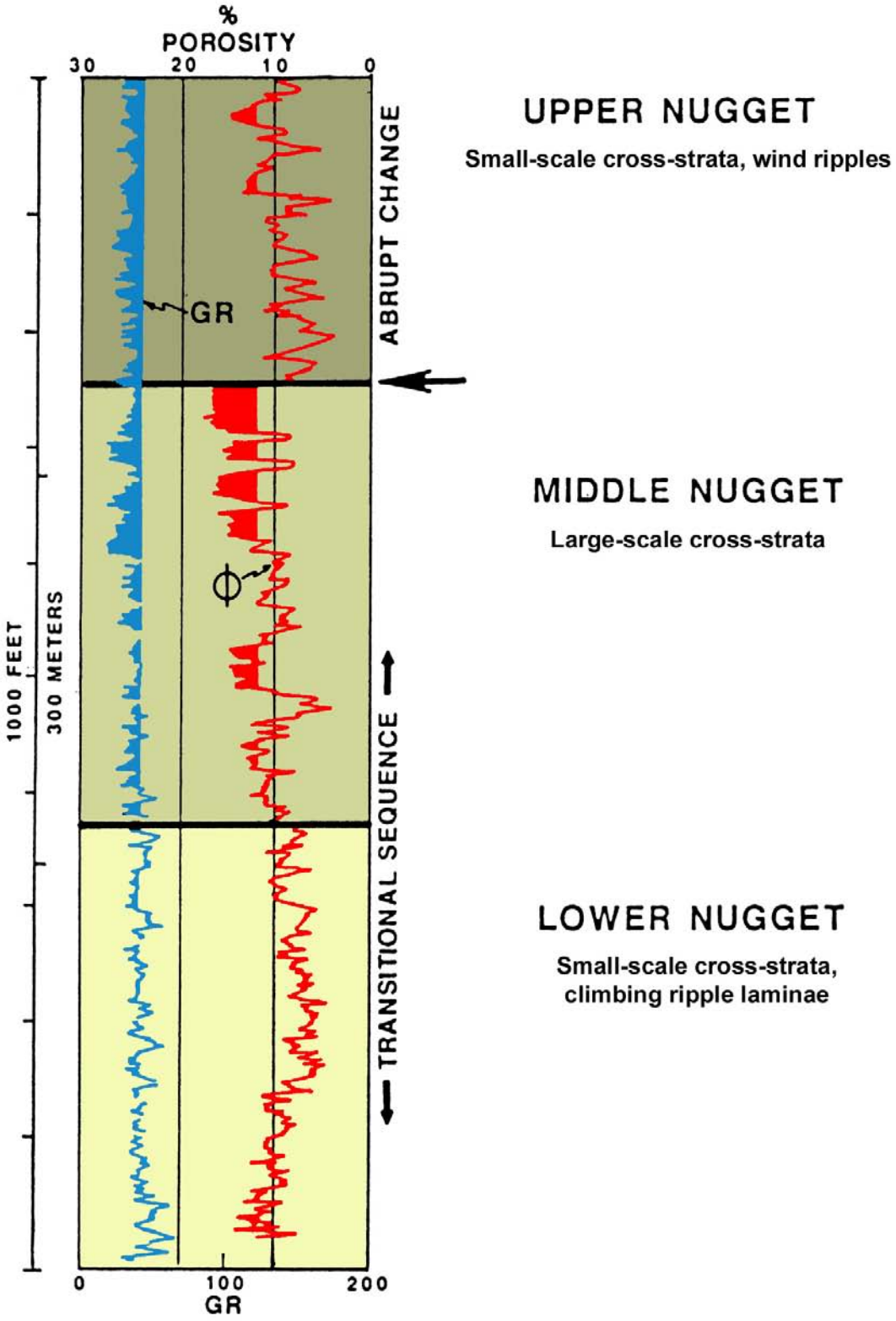


Figure 3-5. Reservoir quality of the Nugget Sandstone based on porosity and gamma ray characteristics, ARE No. W29-12 well (NWSW section 29, T. 4 N., R. 8 E., SLBL&M), Anschutz Ranch East field, Summit County, Utah. Modified from Lindquist (1988).



Figure 3-6. Typical Nugget Sandstone, from the Champlin No. 1 McDonald 31-3 well (NWNE section 3, T. 2 N., R. 7 E., SLBL&M, slabbed core from 9872 feet), Pineview field (figure 3-1), showing cross-bedding in fine-grained sandstone deposited in a dune environment.

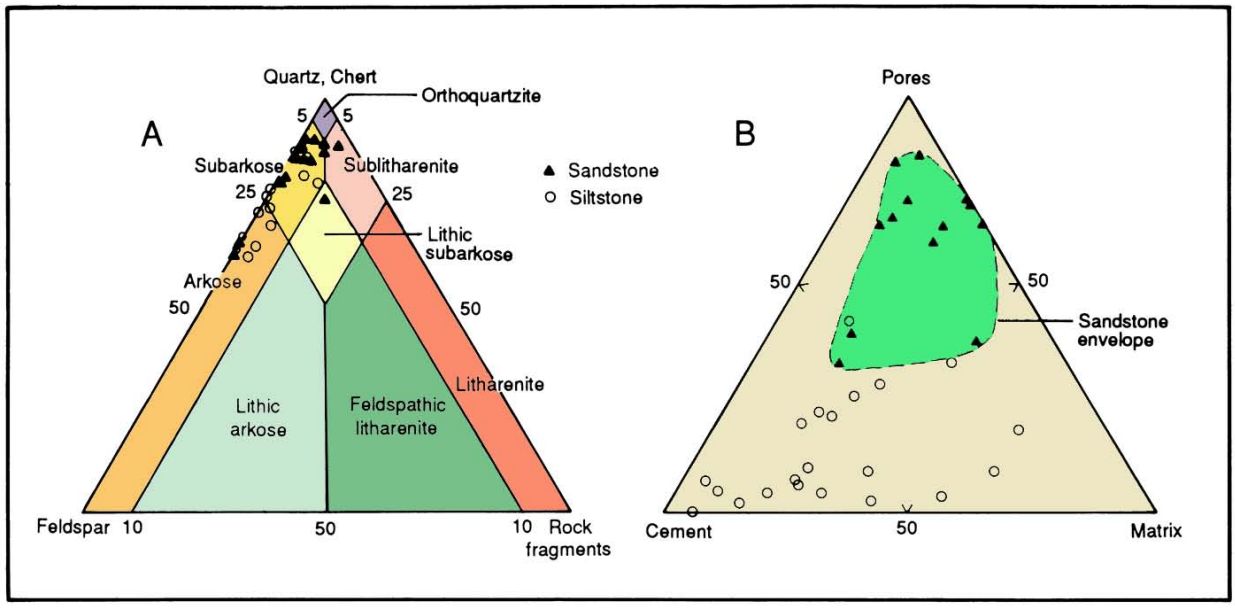


Figure 3-7. Trilinear plots of (A) quartz, feldspar, and rock fragments and (B) pores, cement, and matrix of sandstone and siltstone in the Nugget Sandstone. Matrix grains are <1/16 mm for sandstone and <1/256 mm for siltstone (after Picard, 1975).

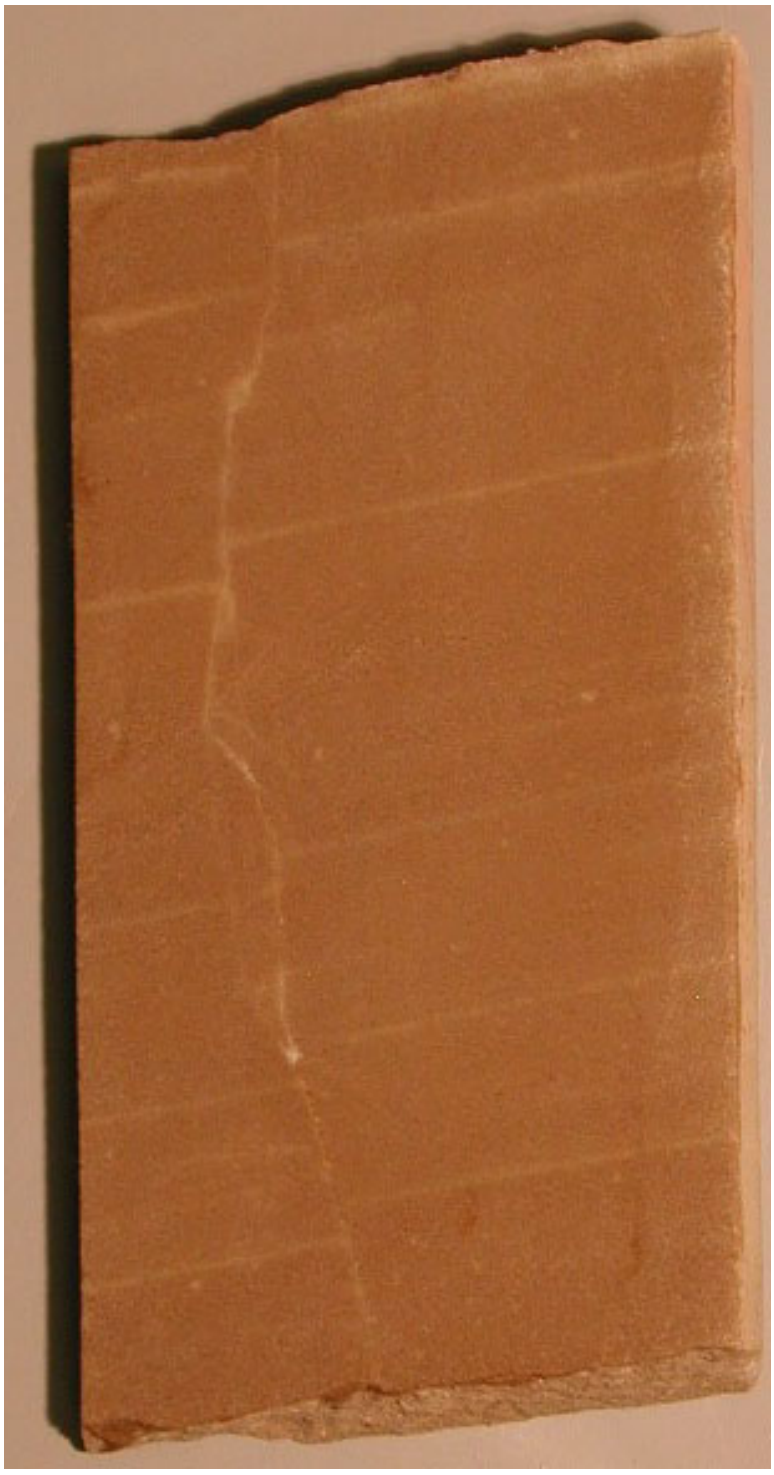


Figure 3-8. Early, gouge-filled and cemented fractures, with slight offsets, in the Nugget Sandstone, from the Champlin No. 1 McDonald 31-3 well (NWNE section 3, T. 2 N., R. 7 E., SLBL&M, slabbed core from 9898.5 feet), Pineview field (figure 3-1).

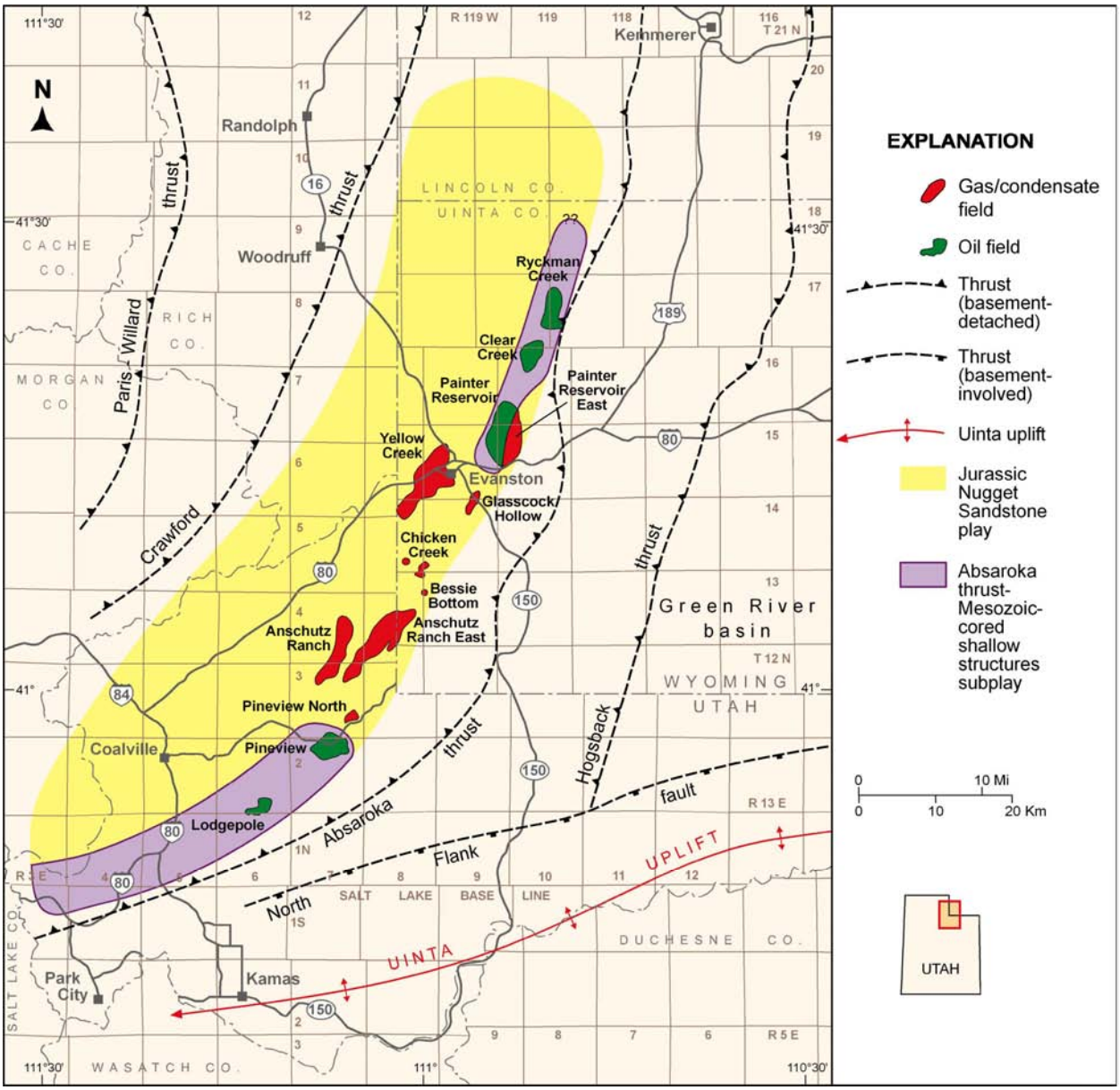


Figure 3-9. Location of the Nugget Sandstone Absaroka thrust – Mesozoic-cored shallow structures subplay, Summit County, Utah and Uinta County, Wyoming. Northern extent of the subplay is unknown.

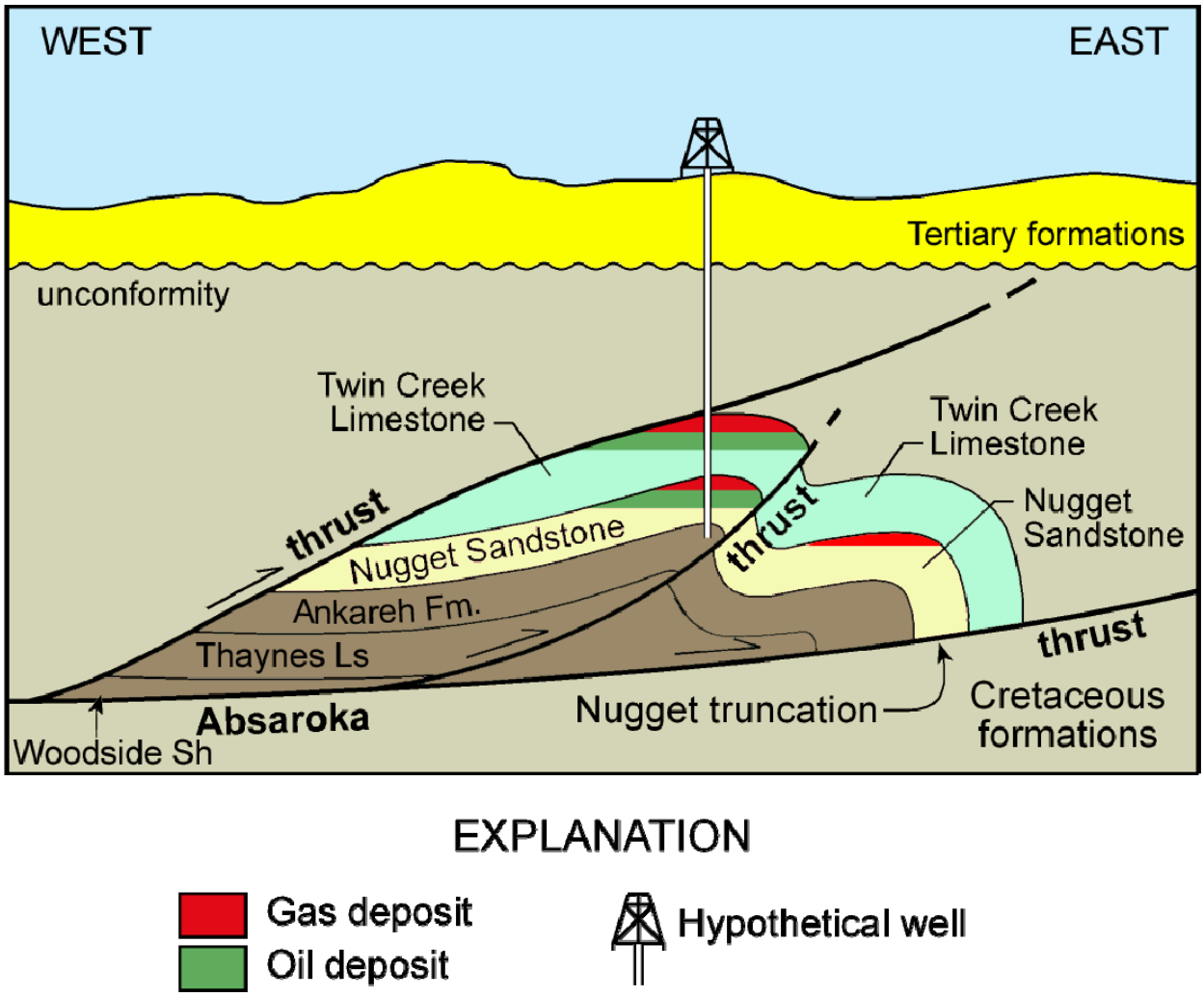


Figure 3-10. Schematic cross section of traps in the Nugget Sandstone Absaroka thrust – Mesozoic-cored shallow and deep structures subplays.

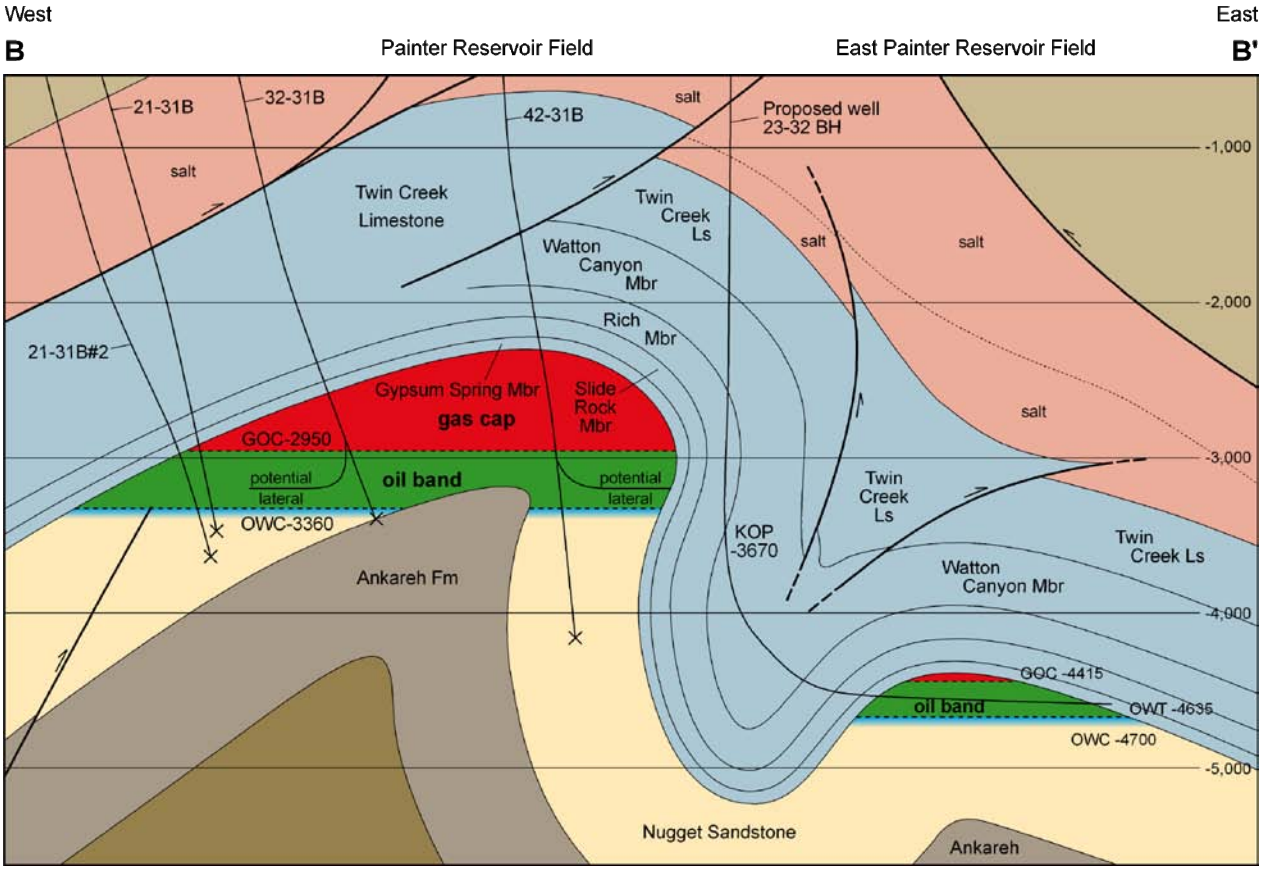


Figure 3-11. East-west structural cross section through the Painter Reservoir and East Painter Reservoir fields, Uinta County, Wyoming, showing typical traps for Nugget Sandstone fields. The cross section also shows the geometry of the structure in the shallow (Painter Reservoir) and deep (Painter Reservoir East) Mesozoic-cored structure subplays. Depth in feet, datum = mean sea level. Modified from Wyoming Oil and Gas Conservation Commission (1998a).

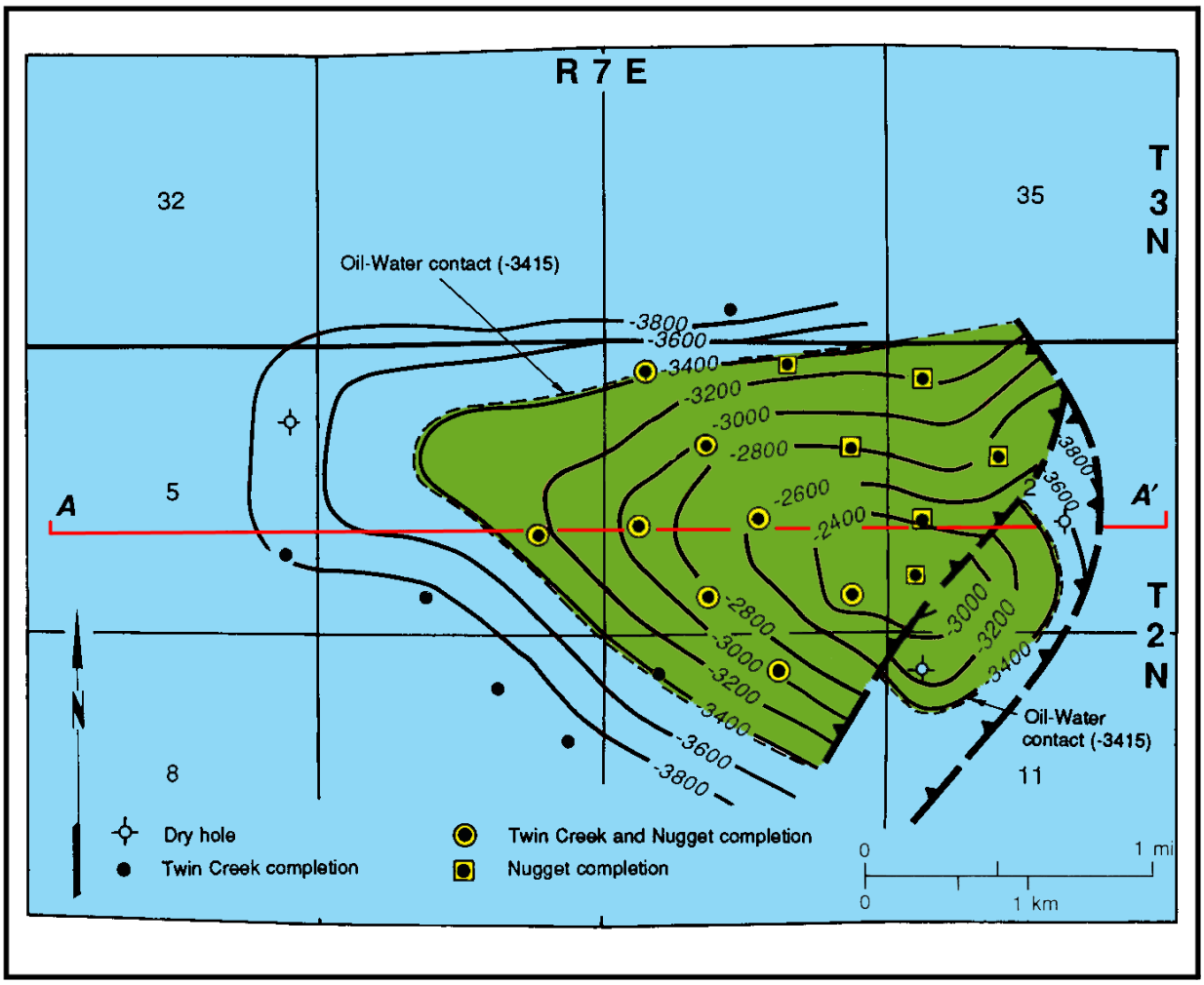


Figure 3-12. Structure contour map of the top of the Nugget Sandstone, Pineview field, Summit County, Utah, typical of the geometry of Mesozoic-cored shallow structures on the southern culmination, Jurassic Nugget Sandstone and Twin Creek Limestone thrust belt plays. Oil is trapped in an asymmetrical thrusted anticline in the hanging wall of the Absaroka thrust system. Contour interval = 200 feet, datum = mean sea level. After Utah Division of Oil, Gas and Mining (1978). Cross section A-A' shown on figure 3-13.

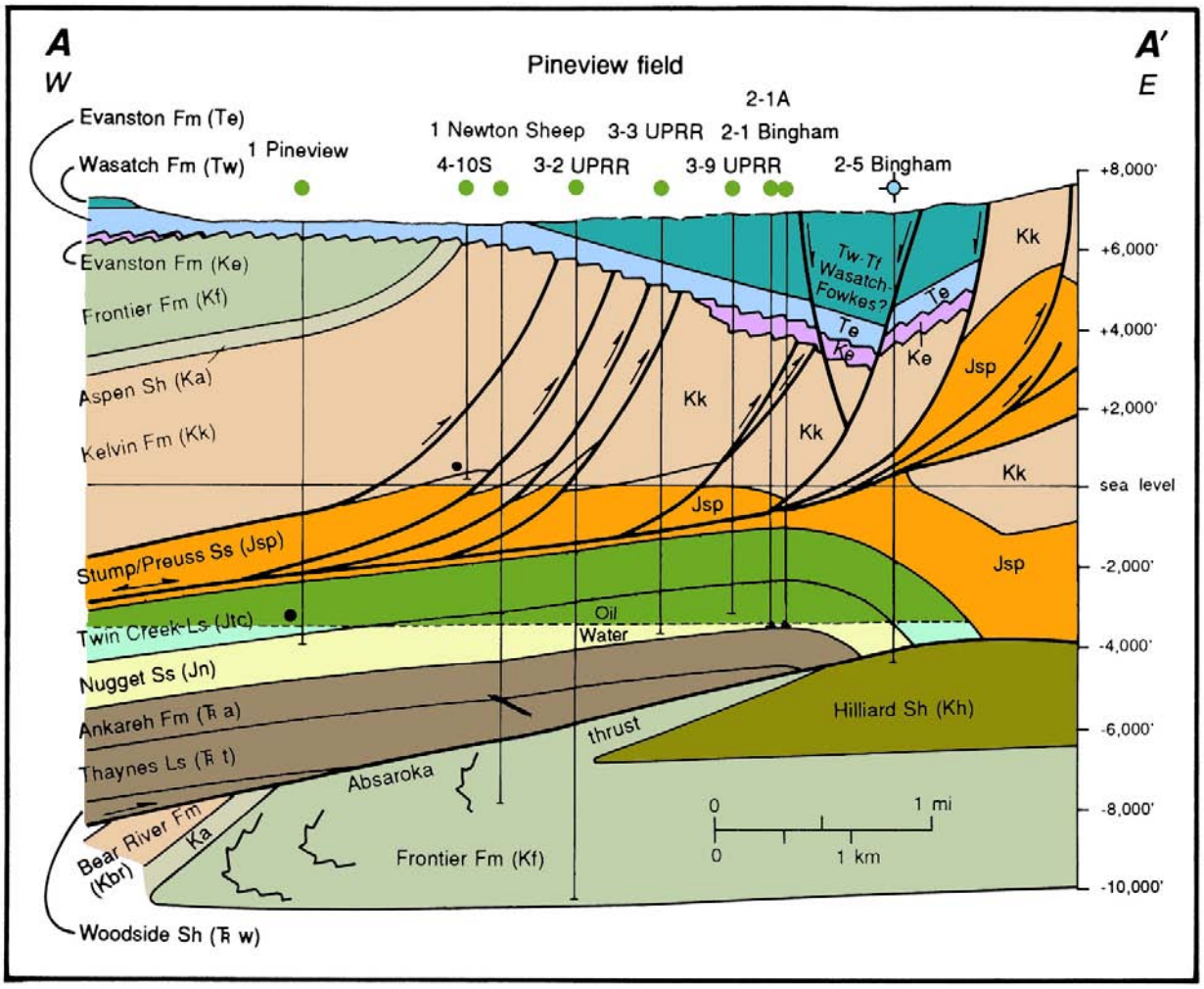


Figure 3-13. East-west cross section through the Pineview structure. Line of section shown on figure 3-12. Note that the field also produces oil from the Jurassic Twin Creek Limestone that has a common oil/water contact with the Nugget. Reservoir zones are juxtaposed against Cretaceous source rocks in the subthrust along the east flank of the structure. After Lamerson (1982).

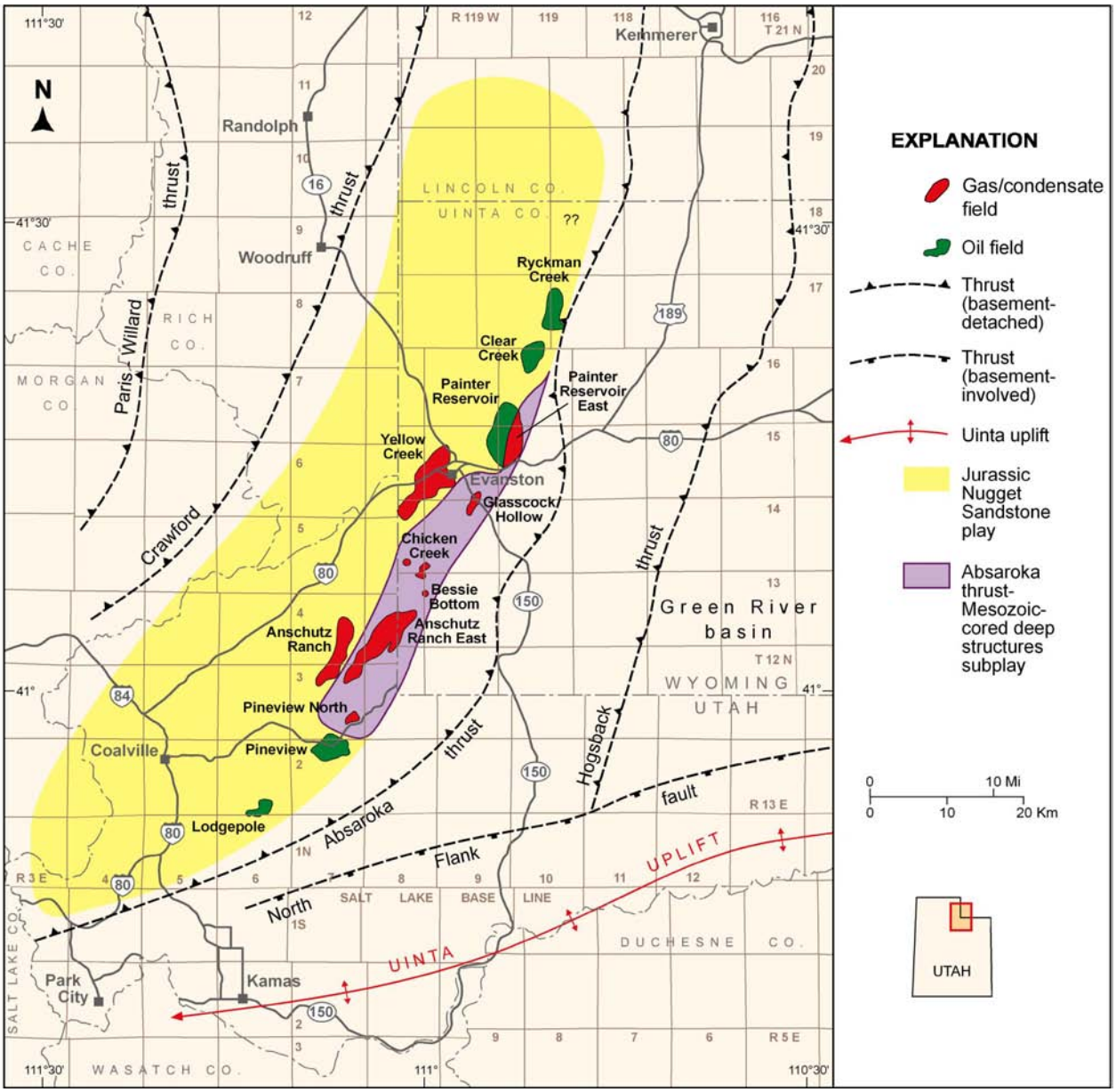


Figure 3-14. Location of the Nugget Sandstone Absaroka thrust – Mesozoic-cored deep structures subplay, Summit County, Utah and Uinta County, Wyoming. Northern extent of the subplay is unknown.

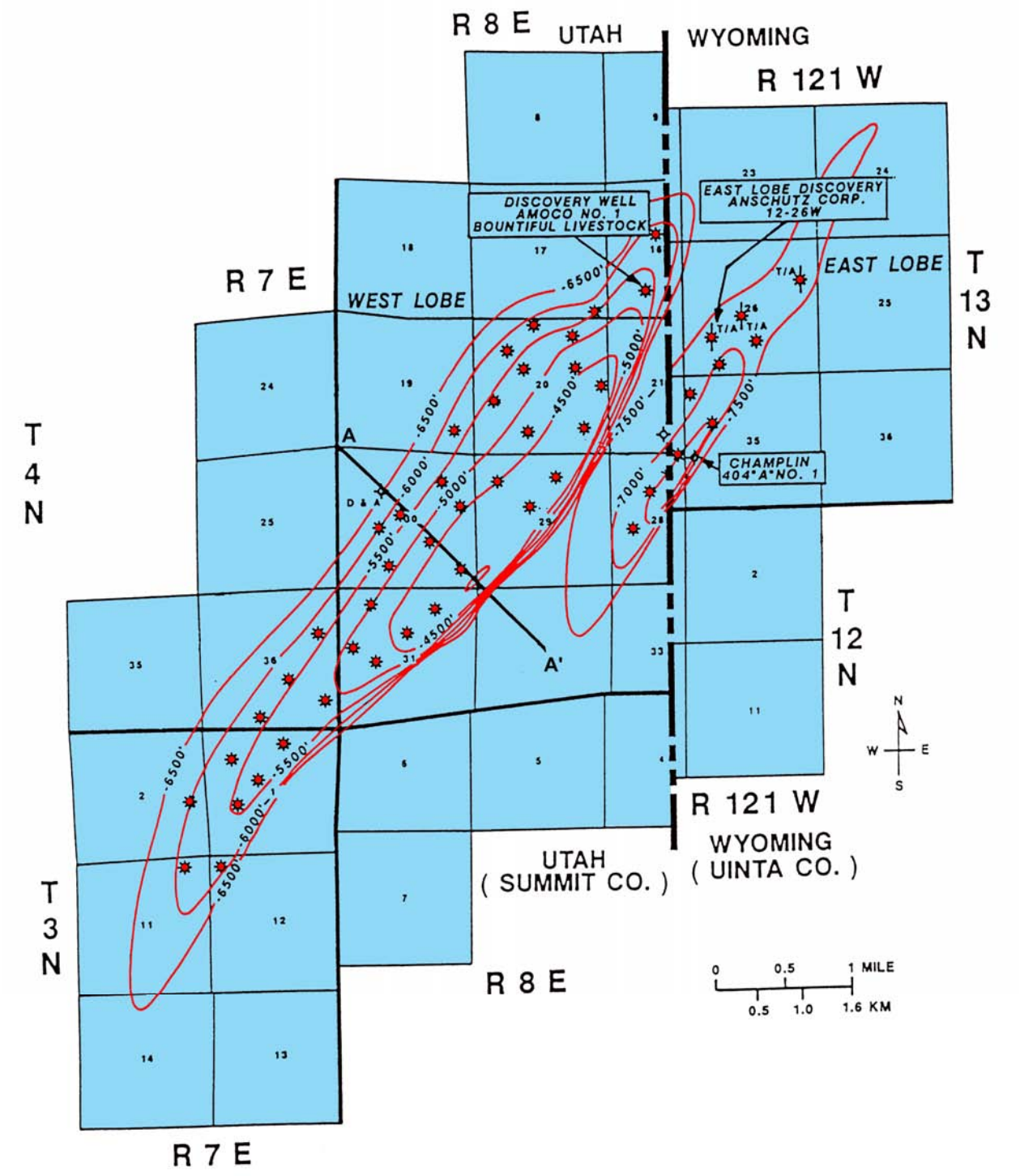


Figure 3-15. Structure contour map of the top of the Nugget Sandstone, Anschutz Ranch East field, Summit County, Utah and Uinta County, Wyoming, typical of the geometry of Mesozoic-cored deep structures, Jurassic Nugget Sandstone thrust belt play. Retrograde condensate and gas are trapped in east and west lobes of a large northeast-southwest-trending, thrusted anticline in the hanging wall of the Absaroka thrust system. Contour interval = 500 feet, datum = mean sea level. After Lelek (1982). Cross section A-A' shown on figure 3-16.

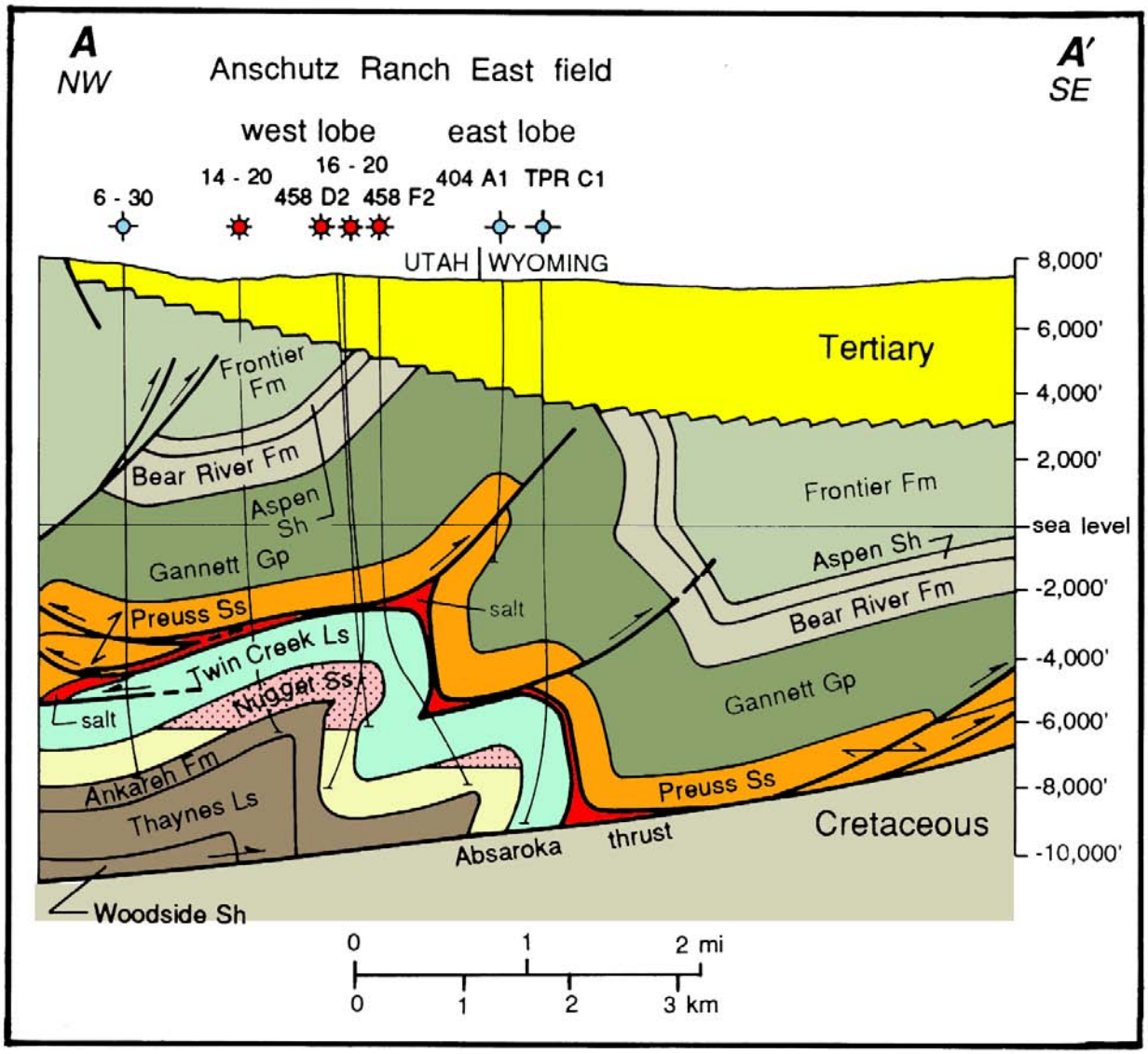


Figure 3-16. Northwest-southeast cross section through the Anschutz Ranch East structure showing the large west lobe and the deeper, smaller east lobe (base of pink stippled area represents the gas-water contact). Line of section shown on figure 3-15. After West and Lewis (1982).

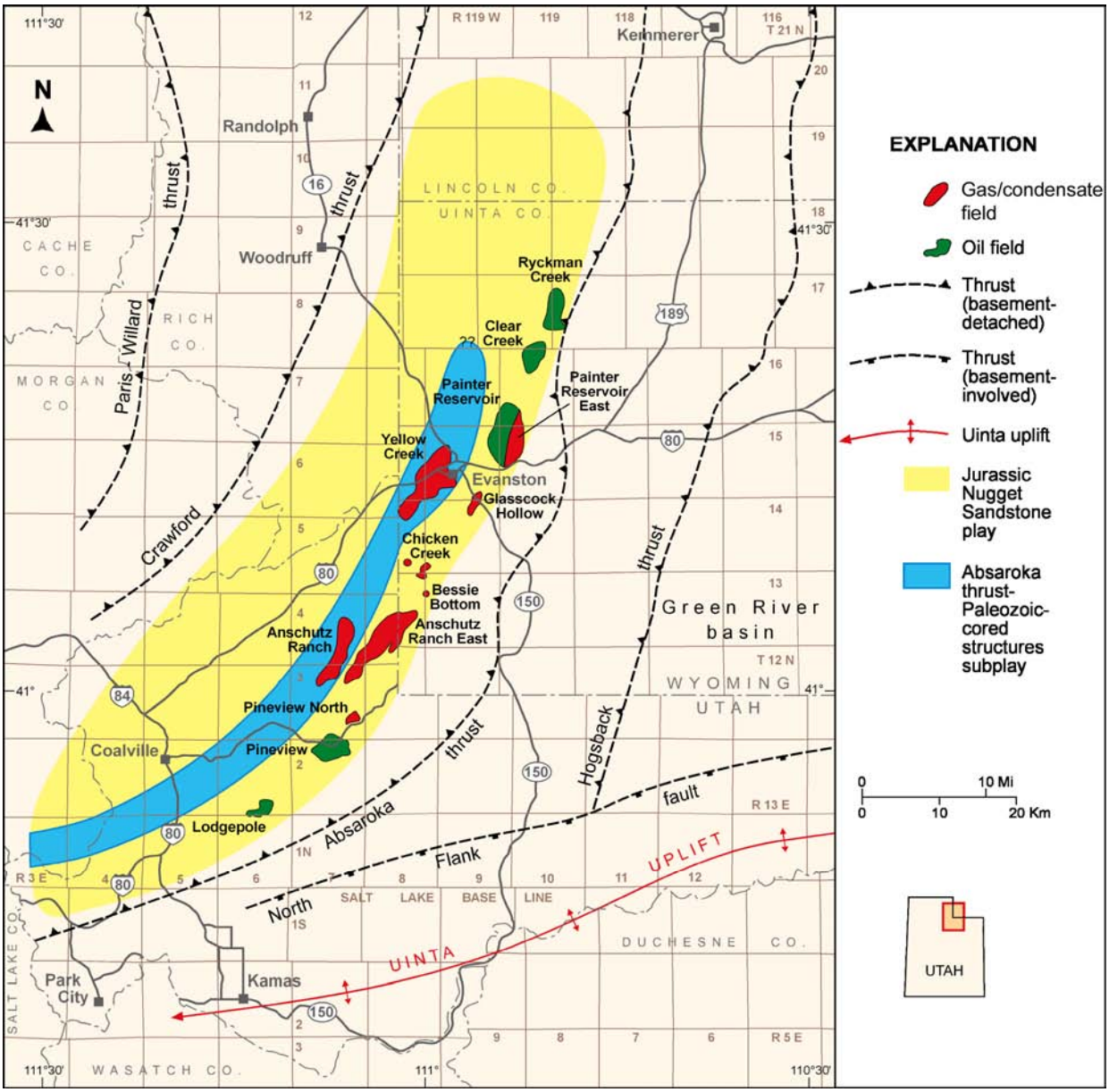


Figure 3-17. Location of the Nugget Sandstone Absaroka thrust – Paleozoic-cored shallow structures subplay, Summit County, Utah and Uinta County, Wyoming. Northern extent of the subplay is unknown.

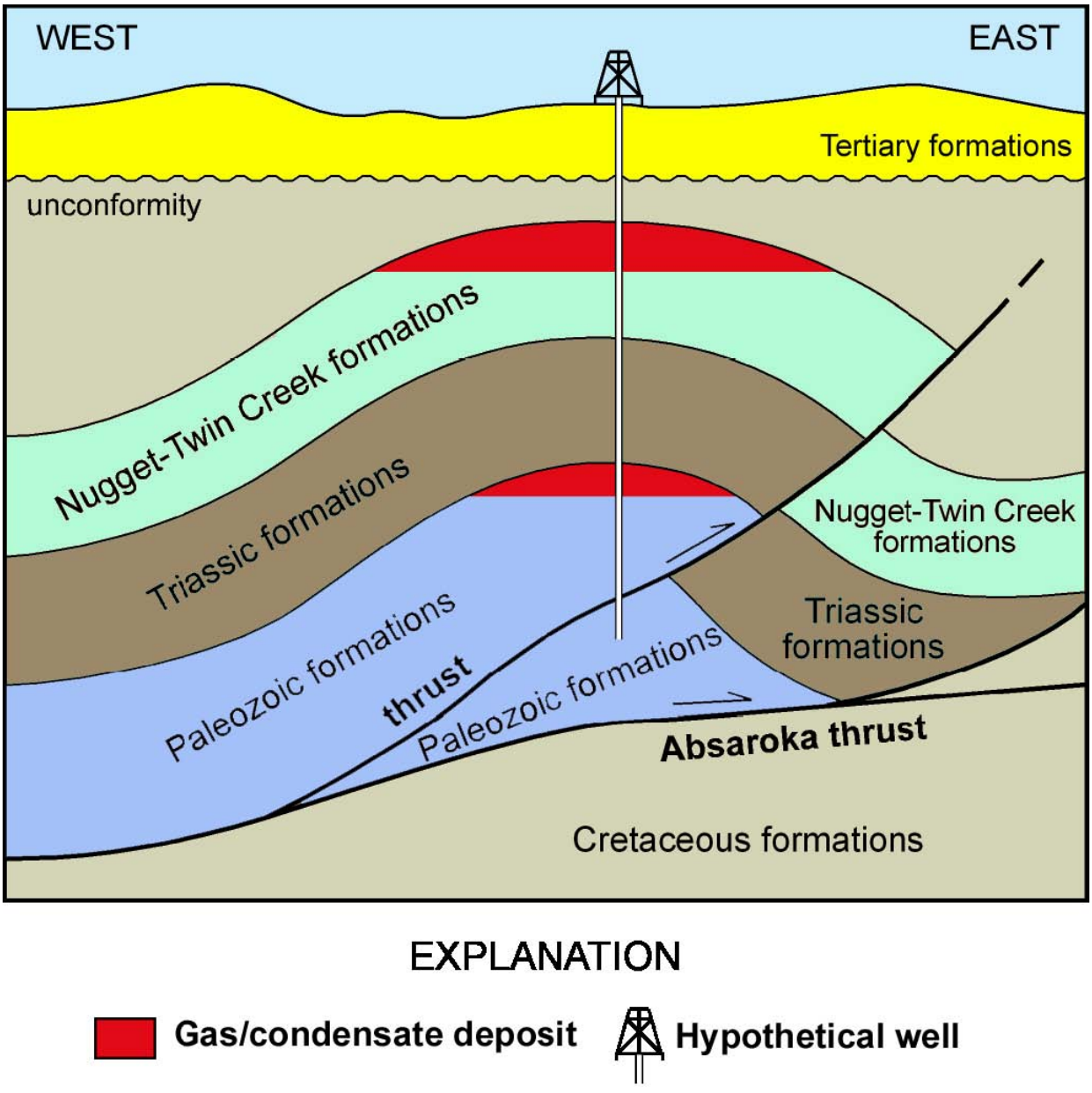


Figure 3-18. Schematic cross section of traps in the Nugget Sandstone and Twin Creek Limestone Absaroka thrust – Paleozoic-cored shallow structures subplays.

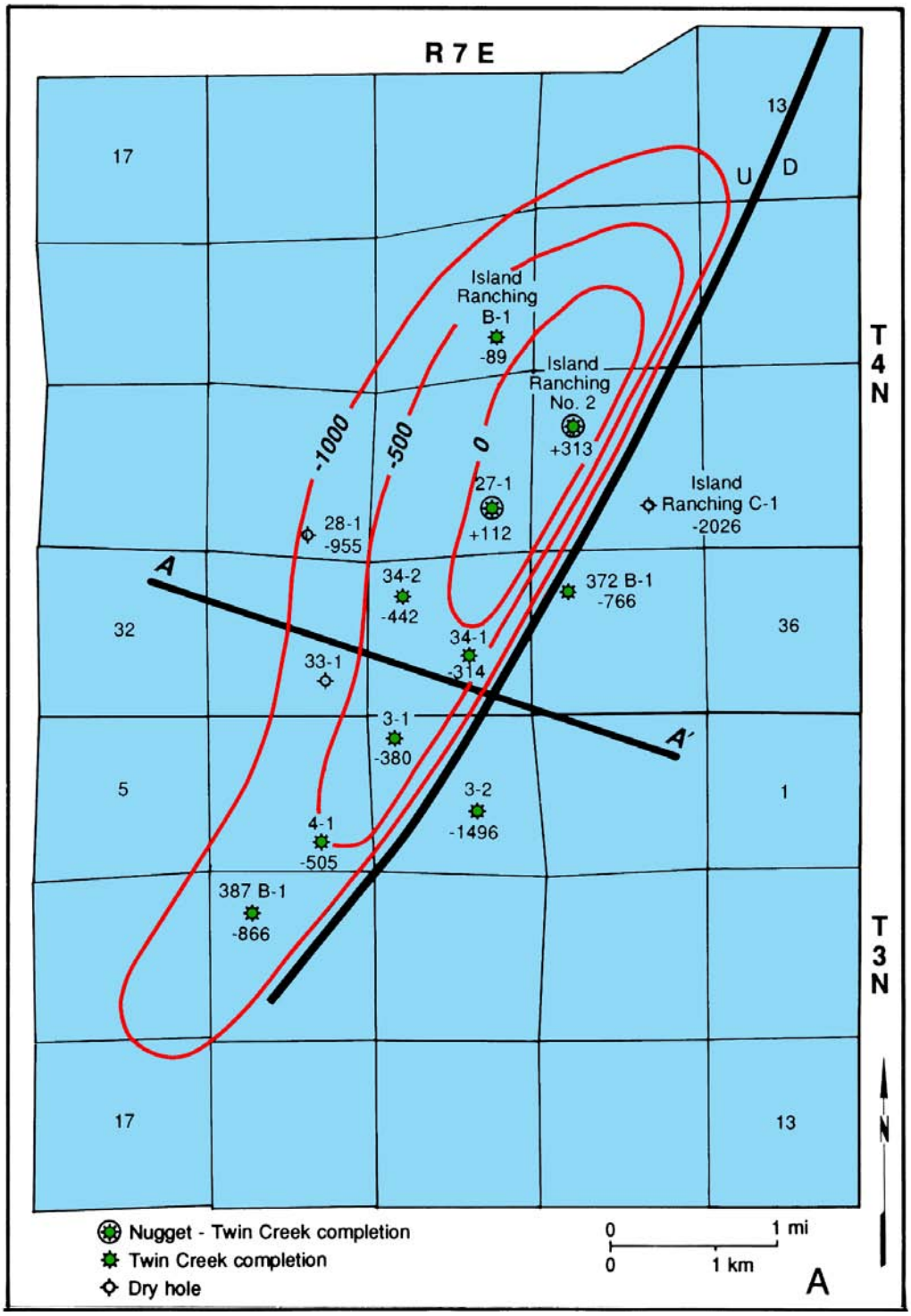


Figure 3-19. Structure contour map of the top of the Nugget Sandstone, Anschutz Ranch field, Summit County, Utah, typical of the geometry of Paleozoic-cored shallow structures in the Jurassic Nugget Sandstone thrust belt play. Gas and condensate are trapped only on the very crest of a large northeast-southwest-trending, doubly plunging, asymmetric, thrusted anticline in the hanging wall of the Absaroka thrust system. Contour interval = 500 feet, datum = mean sea level. Modified from Utah Division of Oil, Gas and Mining (1980a). Cross section A-A' shown on figure 3-20.

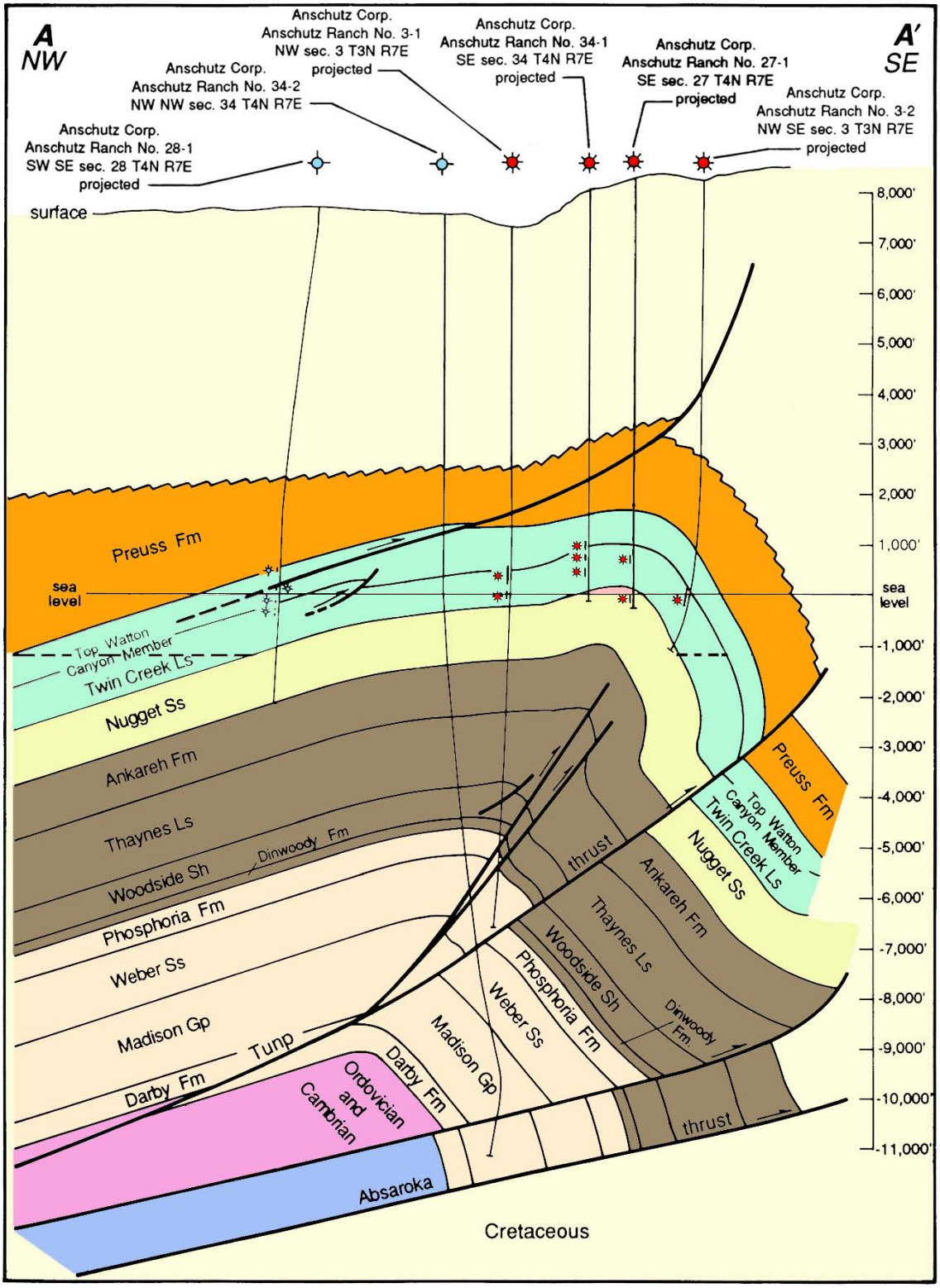


Figure 3-20. Northwest-southeast cross section through the Anschutz Ranch structure. Line of section shown on figure 3-19. Cretaceous formations in the footwall of the Absaroka thrust system charge the overlying, fractured sandstone units of the Nugget Sandstone with gas and condensate. Modified from Utah Division of Oil, Gas and Mining (1980c).

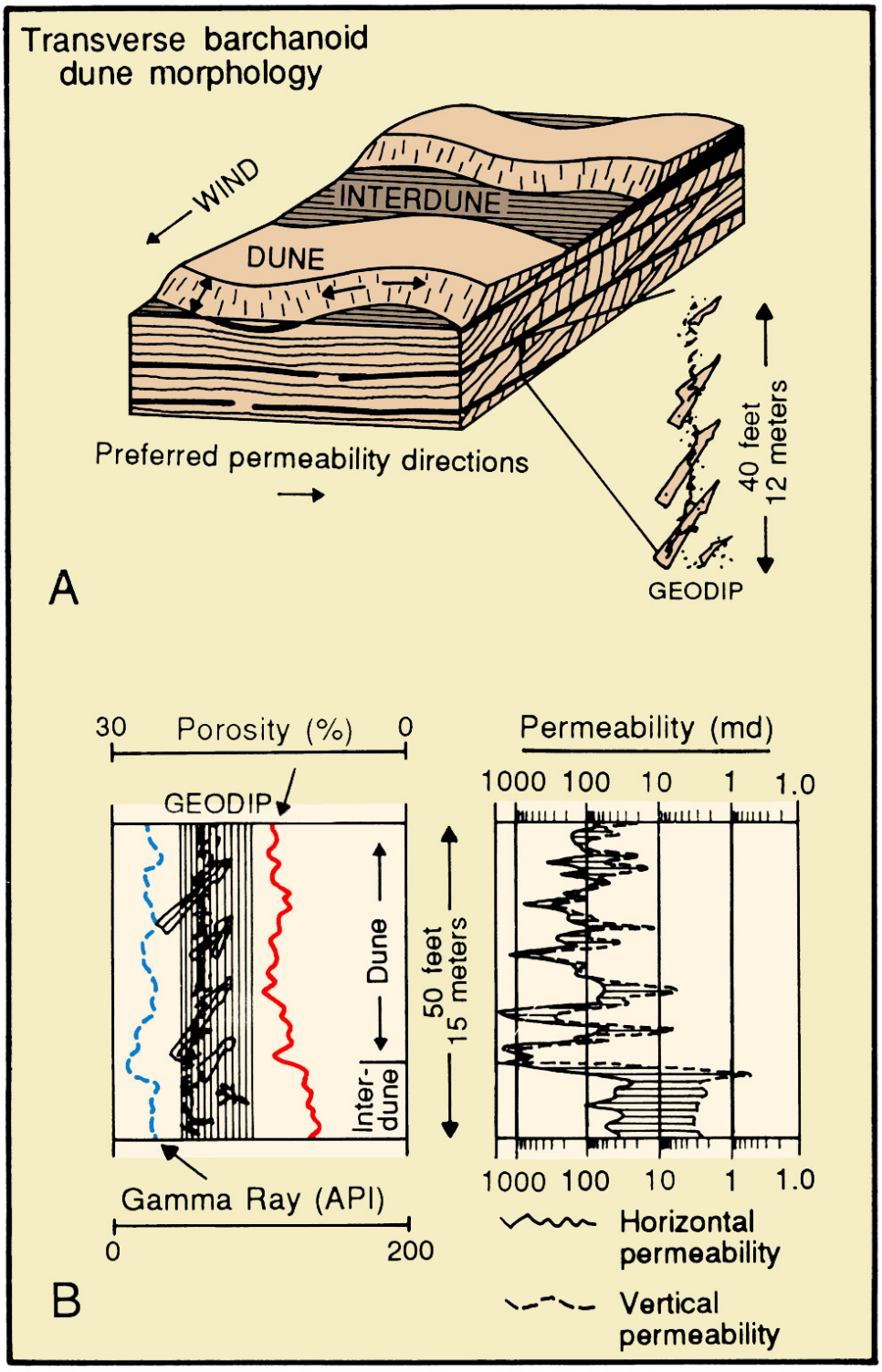


Figure 3-21. Transverse barchanoid dune morphology. A - Schematic dune/interdune sequence in the Nugget Sandstone correlating transverse barchanoid dune morphology to structurally corrected stratigraphic dipmeter data (Geodip). The slipface of a dune (surface between the dune brink and toe), on which deposits form cross-beds, dips in the downwind, dune-migrating direction. Arrows indicate preferred permeability directions along the dip and strike of dune slipfaces (cross-beds). B - Geophysical logs demonstrate the differences in porosity and directional permeability between the dune and interdune lithofacies. Lined area indicates vertical and horizontal permeability contrasts particularly within the interdune lithofacies (after Lindquist, 1983).



Figure 3-22. Color changes in retrograde condensate from Anschutz Ranch East field, Summit County, Utah. Sample bottles are labeled with subsea structural elevation.

Table 3-1. Geologic, reservoir, and production data for fields in the Jurassic Nugget Sandstone thrust belt play. Data compiled from Loucks (1975), Conner and Covlin (1977), Kelly and Hine (1977), Jones (1979), Moklestad (1979), Petroleum Information (1981, 1984b), Frank and Gavlin (1981), Frank and others (1982); Sercombe (1989), Chase and others (1992a, 1992b), Holm (1992), Mullen (1992a, 1992b), Powers (1992), Benson (1993a), Cook and Dunleavy (1993), Chidsey (1993), Lindquist and Ross (1993), Utah Division of Oil, Gas and Mining (2008, and well records), and Wyoming Oil & Gas Conservation Commission (2008).

State	County	Field	Discovery Date	Active Producers	Abandoned Producers	Acres	Spacing (acres)	Pay (feet)	Porosity (%)	Perm. (mD)	Temp. (°F)	Initial Reservoir Pressure (psi)	Average Monthly Production		Cumulative Production	
													Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (BCF)
Utah	Summit	Pineview	1975	7	5	2180	80	135	11	50	200	4200	8045	11,975	22,239,591	28.7
Utah	Summit	Pineview North	1982	2	3	1200	80	400	12	1.3	205	2000	685	10,099	819,378	9.4
Utah	Summit	Lodgepole	1976	2	5	640	160	43	10	229	188	4474	10	0	247,340	0.2
Utah	Summit	Anschutz Ranch	1979	2	2	1680	160	300	11	16	146	2915	0	0	555,367	43.1
Utah/ Wyoming	Summit/ Uinta	Anschutz Ranch East	1979	49	8	4500	80	W-300 E-501	W-10.1 E-9	W-3 E-2	W-215 E-230	W-5310 E-5902	9,207	827,780*	128,553,460	295.1*
Wyoming	Uinta	Ryckman Creek	1976	1	37	1200	40	22	15	34	129	2900	0	0	18,951,863	259.7
Wyoming	Uinta	Clear Creek	1979	13	1	1200	80	30	13	5.4	138	3443	0	0	5,747,743	142.3
Wyoming	Uinta	Painter Reservoir	1977	54	10	1666	40	450	12	7.1	164	4020	6139	847,394	38,100,316	717.8
Wyoming	Uinta	East Painter Reservoir	1987	48	1	1200	80	900	12	5.4	170	NA	118,862	6,676,222	67,847,486	937.3
Wyoming	Uinta	Yellow Creek	1976	0	3	480	160	300	NA	NA	117	NA	0	0	221,048	0.3
Wyoming	Uinta	Glasscock Hollow	1980	6	5	915	none	110	11	65	220	5620	4245	97,390	2,831,528	17.0
Wyoming	Uinta	Chicken Creek	1983	3	4	430	160	200	11	NA	219	6021	998	5204	938,231	5.7
Wyoming	Uinta	Bessie Bottom	1983	1	0	160	160	170	8.5	0.6	242	6227	713	4180	160,356	1.5

NA = Not Available
For Anshcutz Ranch East field, W = West Lobe and E = East Lobe
*Includes cycled gas

CHAPTER 4
JURASSIC TWIN CREEK LIMESTONE THRUST BELT PLAY

Thomas C. Chidsey, Jr., and Douglas A. Sprinkel,
Utah Geological Survey

Introduction

A prolific oil and gas play confined to the hanging wall of the Absaroka thrust system is the Jurassic Twin Creek Limestone thrust belt play (figure 4-1). The Twin Creek has produced over 15 million barrels (2.4 million m^3) of oil and 93 billion cubic feet (2.6 billion m^3) of gas (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008). The play outline represents the maximum extent of petroleum potential in the geographical area as defined by producing reservoirs, hydrocarbon shows, and untested hypotheses. The attractiveness of the Twin Creek thrust belt play (and other thrust belt plays) to the petroleum industry depends on the likelihood of successful development, reserve potential, pipeline access, drilling costs, oil and gas prices, and environmental concerns. When evaluating these criteria, certain aspects of the Twin Creek play may meet the exploration guidelines of major oil companies while other aspects meet the development guidelines of small, independent companies.

Like the Jurassic Nugget Sandstone reservoir below, prospective drilling targets in the Twin Creek Limestone thrust belt play are also delineated using high-quality seismic data (two-dimensional [2-D] and three-dimensional [3-D]), 2-D and 3-D forward modeling/visualization tools, well control, dipmeter information, high-quality surface geologic maps, and detailed analyses of structural geometry (Chidsey, 1999; Meneses-Rocha and Yurewicz, 1999). Incremental restoration of balanced cross sections is one of the best methods to access trap geometry (Meneses-Rocha and Yurewicz, 1999). Several techniques can be used to determine the timing of structural development, petroleum migration, and entrapment, and to decipher fill and spill histories. These techniques include illite age analysis, apatite fission track analysis, and use of fluid inclusions (Meneses-Rocha and Yurewicz, 1999).

The Jurassic Twin Creek Limestone thrust belt play is in the southwest Wyoming and northern Utah thrust belt (figure 4-1). Pineview field was the first to produce oil and gas from the Twin Creek in 1975 (Conner and Covlin, 1977; Petroleum Information, 1981). There are currently seven Twin Creek fields, with only one in Wyoming (Yellow Creek). Geologic data for individual fields in the play are summarized in table 4-1. The Twin Creek Limestone play is divided into two subplays (1) Absaroka thrust – Mesozoic-cored structures and (2) Absaroka thrust – Paleozoic-cored structures.

Depositional Environment

The Twin Creek Limestone and equivalent rocks were deposited in a shallow-water embayment south of the main body of a Middle Jurassic sea that extended from Canada to southern Utah (figure 4-2) (Imlay, 1980; Kocurek and Dott, 1983; Hintze, 1993). Eustatic fluctuations caused numerous transgressions and regressions resulting in deposition of shallow-water carbonates, fine-grained clastic redbeds, and sabkha evaporites (Imlay, 1967, 1980;

Kocurek and Dott, 1983). Carbonate mudstone (figure 4-3) was deposited in backbank, low-energy brackish water environments. Sporadic oolitic- and peloid-bearing beds represent higher energy environments; a few zones contain fossils and fossil hash.

Stratigraphy and Thickness

Seven formal members are recognized in both nearby outcrops and the subsurface within the Twin Creek Limestone thrust belt play area (Imlay, 1967) and each member has a characteristic geophysical log response (figure 4-4). Thickness of the Twin Creek ranges from approximately 1400 feet to nearly 1900 feet (470-630 m) (Imlay, 1967; Sprinkel and Chidsey, 1993) in the thrust belt, where it is overlain by the Preuss Formation and underlain by the Nugget Sandstone, both Jurassic in age. The average depth to the Twin Creek for these reservoirs is 6598 feet (2011 m).

Lithology and Fracturing

The Twin Creek Limestone is composed of a variety of lithologies including micritic to argillaceous limestone, evaporites, and siltstone and claystone. Tightly cemented oolitic grainstone, dolomitized zones, and thin shaly intervals are also present (Bruce, 1988; Parra and Collier, 2000). Post-burial diagenesis includes cementation, compaction, and fracturing. Oil and gas production comes from zones in the denser, naturally fractured carbonate beds in the middle to lower part of the formation (figure 4-5). Fracturing is related to fault-propagation folding during the Sevier orogeny (Royce and others, 1975; Conner and Covlin, 1977; Dixon, 1982; Lamerson, 1982; Bruce, 1988). In Lodgepole field (figure 4-1) and elsewhere, the fracture intensity is controlled by lithology (Parra and Collier, 2000). Dolomitized mudstone has considerable fracturing; for example, significant fracturing occurs near the base of the Watton Canyon Member. Fracture intensity decreases as silt content increases and dolomitization decreases; for example, only rare fractures are found in the Giraffe Creek and upper Leeds Creek Members (Parra and Collier, 2000).

Hydrocarbon Source and Seals

Hydrocarbons in Twin Creek Limestone reservoirs were generated from the same subthrust Cretaceous source rocks as those that sourced the Nugget Sandstone (Warner, 1982; Bruce, 1988). These include organic-rich units in the Bear River, Aspen (Mowry equivalent [Nixon, 1973]), and Frontier Formations. The source rocks began to mature after being overridden by thrust plates. Hydrocarbons were then generated, expelled, and subsequently migrated, primarily along fault planes, into overlying traps during the last 55 million years (Warner, 1982).

Burtner and Warner (1984) evaluated the hydrocarbon generation from the Mowry Shale in the Green River Basin (overridden in the western part by the thrust belt) and other northern Rocky Mountain basins. Their study showed that the Mowry ranges from 0.7 to 4.1 weight percent total organic content (TOC) and contains a mixture of type II (marine) and type III (terrestrial) organic matter. In the Green River Basin, areas of Mowry with T_{max} values (the temperature during pyrolysis of peak hydrocarbon generation) greater than 435ºC coincide with

areas anomalously low in TOC, indicating that hydrocarbons and CO_2 were generated and subsequently migrated out of the source beds (Burtner and Warner, 1984).

The seals for the producing horizons are overlying argillaceous and clastic beds, and non-fractured units within the Twin Creek Limestone. Hydrocarbons in the Twin Creek are further sealed by salt beds within the overlying Preuss Formation.

Structure and Trapping Mechanisms

Absaroka Thrust – Mesozoic-Cored Structures Subplay

The Twin Creek Limestone Absaroka thrust – Mesozoic-cored structures subplay is located in the western part of Summit County, Utah and Uinta County, Wyoming (figure 4-6). The subplay represents a linear, hanging wall, Mesozoic-cored, ramp anticline parallel to the leading edge of the Absaroka thrust (figure 3-10). This ramp anticline can be divided into a broad structural high (culmination) and a structural low (depression) within the subplay area. The culmination is present in the southern part of the subplay and related to the proximity of a transverse ramp associated with the Uinta uplift (Lamerson, 1982; Chidsey, 1993). The depression is located in the northernmost part of the subplay area in Summit County, Utah, and southwestern Uinta County, Wyoming, between the culmination to the south and another culmination related to the Muddy Creek transverse ramp to the north in Lincoln County, Wyoming (figure 4-1) (Lamerson, 1982; Chidsey, 1993). The eastern boundary of the subplay is defined by the truncation of the Twin Creek Limestone against the leading edge of the Absaroka thrust. The western boundary is defined by a branch line representing the intersection of the thrust planes of the Absaroka thrust and a large imbricate thrust (Boyer and Elliott, 1982). The southern part of the Absaroka thrust plate trends southwest toward the Wasatch Range where the Twin Creek Limestone play area terminates. The subplay extends north as a 5-mile- (8-km-) wide band into Uinta County, Wyoming (figure 4-6).

Potential petroleum-trapping mechanisms in the Twin Creek Limestone Absaroka thrust - Mesozoic-cored structures subplay consist of long, narrow, doubly plunging anticlines (Royce and others, 1975; Conner and Covlin, 1977; Dixon, 1982; Lamerson, 1982). These anticlines are asymmetric, overturned to the east, and often develop en echelon structures along the leading edge of the Absaroka thrust because of variations in the competence and thickness of the stratigraphic sequence (West and Lewis, 1982). Traps on the culmination typically produce oil and associated gas; traps on the depression produce nonassociated gas and retrograde condensate. All fields in the Twin Creek Limestone Absaroka thrust - Mesozoic-cored structures subplay are located on subsidiary closures associated with the southern culmination in Utah. Pineview field, Summit County, Utah, exemplifies the traps in the subplay (figures 4-6, 3-12, and 3-13). The reservoir covers approximately 1280 acres (572 ha) with more than 1000 feet (300 m) of structural closure. However, to date, no Twin Creek production has been discovered on traps in the structural depression.

Absaroka Thrust – Paleozoic-Cored Structures Subplay

The Twin Creek Limestone Absaroka thrust – Paleozoic-cored structures subplay is located immediately west of the Mesozoic-cored structures subplay (figure 4-7). The subplay represents a very continuous and linear, hanging wall, Paleozoic-cored, ramp anticline parallel to

the leading edge of the Absaroka thrust (figure 3-18). The eastern boundary of the subplay is defined by the truncation of the Twin Creek against a thrust splay. The western boundary is defined as the point at which the dips on the west flank of the ramp anticline begin to flatten out. The southern part of this ramp anticline trends southwest toward the Wasatch Range where the play area terminates. The play extends north as a 3-mile- (4.8-km-) wide band through Summit County, Utah and into Uinta County, Wyoming (figure 4-7).

Potential petroleum-trapping mechanisms in the Twin Creek Limestone Absaroka thrust - Paleozoic-cored structures play also consist of long, narrow, doubly plunging anticlines that trend north to northeast (figures 4-8 and 4-9) (Royce and others, 1975; Conner and Covlin, 1977; Petroleum Information, 1981; Dixon, 1982; Lamerson, 1982; Bruce, 1988). These anticlines are also asymmetric and overturned to the east. Splay faults and salt near the anticlinal axes are common, complicating drilling operations and compartmentalizing productive zones. There are three fields in the Twin Creek Limestone Absaroka thrust - Paleozoic-cored structures subplay (figure 4-7). For example, the Anschutz Ranch field, Summit County, Utah, consists of a large, elongate anticline with more than 7100 feet (2164 m) of structural closure involving Jurassic through Ordovician rocks; the reservoir covers approximately 2880 acres (1170 ha).

Reservoir Properties

Most oil and gas production is from perforated intervals in the Watton Canyon, upper Rich, and Sliderock Members (figure 4-4). These members have primary porosity ranging from 2 to 4%, when present, in the producing horizons (Bruce, 1988), but exhibit significant secondary porosity in the form of fracturing. Permeabilities in these members range from 4 to more than 30 mD (Benson, 1993a, 1993b; Cook and Dunleavy, 1993; Sprinkel and Chidsey, 1993). The permeability is also formed by natural fractures, and controls hydrocarbon production and injection fluid pathways (Parra and Collier, 2000). Other members produce hydrocarbons, but the volume is typically small and the production zones generally require acidizing or other stimulation. The net pay thickness is variable, depending on fracturing, and ranges from 30 to 150 feet (10-50 m).

Closely spaced fractures are developed on bedding planes and within dense, homogeneous, non-porous (in terms of primary porosity) limestone beds of the Rich and Watton Canyon Members. The contact with the basal siltstone units (where fractures are sealed) of the overlying members set up the Rich and Watton Canyon for hydrocarbon trapping and production. Thin-bedded siltstone within the Rich and Watton Canyon Members creates additional reservoir heterogeneity.

The average Twin Creek reservoir temperature is 150ºF (65ºC). Water saturations range from 15 to 37%, with a salinity of 25,000 ppm NaCl and a resistivity (R_w) of 0.160 ohm-m at 68ºF (20ºC) (Benson, 1993a, 1993b; Cook and Dunleavy, 1993). Initial reservoir pressures average about 4200 pounds per square inch (29,000 kPa). The reservoir drive mechanisms include pressure depletion, active drive, and solution gas.

Reservoir data for individual fields in the Jurassic Twin Creek Limestone thrust belt play are summarized in table 4-1.

Oil and Gas Characteristics

In major reservoirs, the produced Twin Creek oil is a volatile crude (gas-oil ratio between

1035 and 1198 cubic feet/bbl) (Sprinkel and Chidsey, 1993). The API gravity of the oil ranges from 24.1º to 45.7º; condensate API gravity ranges from 67.5º to 73.5º. Oil colors vary from amber to dark brown, and condensate is clear. The viscosity of the crude oil averages 2.0 cst at 104ºF (40ºC), but can be as high as 7.9 cst at 122ºF (50ºC); in Saybolt Universal Seconds (sus) the viscosity averages 32.6 sus at 104ºF (40ºC), but can be as high as 51.7 sus at 122ºF (50ºC). The viscosity of the condensate is 0.51 cst and 27.4 sus at 104ºF (40ºC). The pore point of the crude oil ranges from 20 to 70ºF (-7 to 21ºC). The average weight percent sulfur and nitrogen of produced Twin Creek hydrocarbon liquids are 0.07 and 0.008, respectively.

Composition of associated gas from the Pineview Twin Creek Limestone reservoir contains 17% methane, 27% ethane, 35% propane, 16% butane, 4% pentane, and 1% other components (Moore and Sigler, 1987). The gas has a heating value of 2321 Btu/ft^3. Composition of nonassociated gas from Anschutz Ranch, Cave Creek, and Yellow Creek reservoirs is remarkably uniform and significantly different from the associated gas. Gas from these reservoirs contains 75 to 80% methane, 7 to 9% ethane, 4% propane, 3% butane, 1% pentane, 6 to 7% nitrogen, and 1% other components (Petroleum Information, 1981; Moore and Sigler, 1987). Heating values average 1170 Btu/ft^3. Gas produced from the reservoirs in the Twin Creek play contains no hydrogen sulfide.

Production

Fields in the Jurassic Twin Creek Limestone Mesozoic-cored structures subplay produce crude oil and associated gas. Pineview, Elkhorn Ridge, and Lodgepole fields (figure 4-1) are located on the culmination part of the subplay, and combined, have produced 12.2 million bbls of oil (MMBO [1.9 MMCMO]) and 11.9 billion cubic feet of gas (BCFG [0.34 BCMG]) from the Twin Creek as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008) (table 4-1). In the depression part of the subplay, only one well, within Anschutz Ranch East field, is productive from the Twin Creek. There are currently 15 active producers and 19 abandoned wells in the Twin Creek Mesozoic-cored structures subplay (table 4-1).

Current Twin Creek production in the Jurassic Twin Creek Limestone Absaroka thrust - Paleozoic-cored structures subplay consists of nonassociated gas and condensate. Anschutz Ranch, Cave Creek, and Yellow Creek fields (figure 4-1) are located in this subplay and combined have produced 2.9 million bbls of condensate (MMBC [0.5 MMCMC]) and 81.1 BCFG (2.30 BCMG) from the Twin Creek as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008) (table 4-1). There are currently six active and 37 abandoned Twin Creek producers in the Paleozoic-cored structures subplay (table 4-1).

In 2007, the monthly production from the Twin Creek Limestone averaged 1400 bbls of oil (and condensate) (223 MCMO) and 0.014 BCFG (0.0004 BCMG) (Utah Division of Oil, Gas and Mining, 2008; Wyoming Oil & Gas Conservation Commission, 2008). Monthly production peaked in 1979, and has generally declined since then. However, in the 1990s, the intensely fractured and depositionally heterogeneous Watton Canyon and Rich reservoirs of the Twin Creek in the Elkhorn Ridge, Lodgepole, and Pineview fields were successfully exploited using horizontal-drilling techniques. Elkhorn Ridge and Lodgepole fields were sub-commercial prior to the horizontal-drilling programs. A successful horizontal-drilling program also revitalized production from the Twin Creek in Cave Creek field.

Exploration Potential and Trends

Future exploration could focus on more structurally complex and subtle, thrust-related traps that overlie organic-rich Cretaceous strata. Possible structural targets include complex traps formed by true duplexes, overlapping ramp anticlines, and hybrid duplexes (Mitra, 1986). In these structures, the dense, naturally fractured limestone beds and the overlying seals of the Twin Creek Limestone are repeated many times. Other thrust-related structural traps include subtle fault-propagation folds formed by imbricate thrust faults or stacked imbricate faults. These traps may be developed along secondary fault-propagation folds, along backlimb thrust faults, or between imbricate splays on the forelimb of anticlines (Mitra, 1986, 1990).

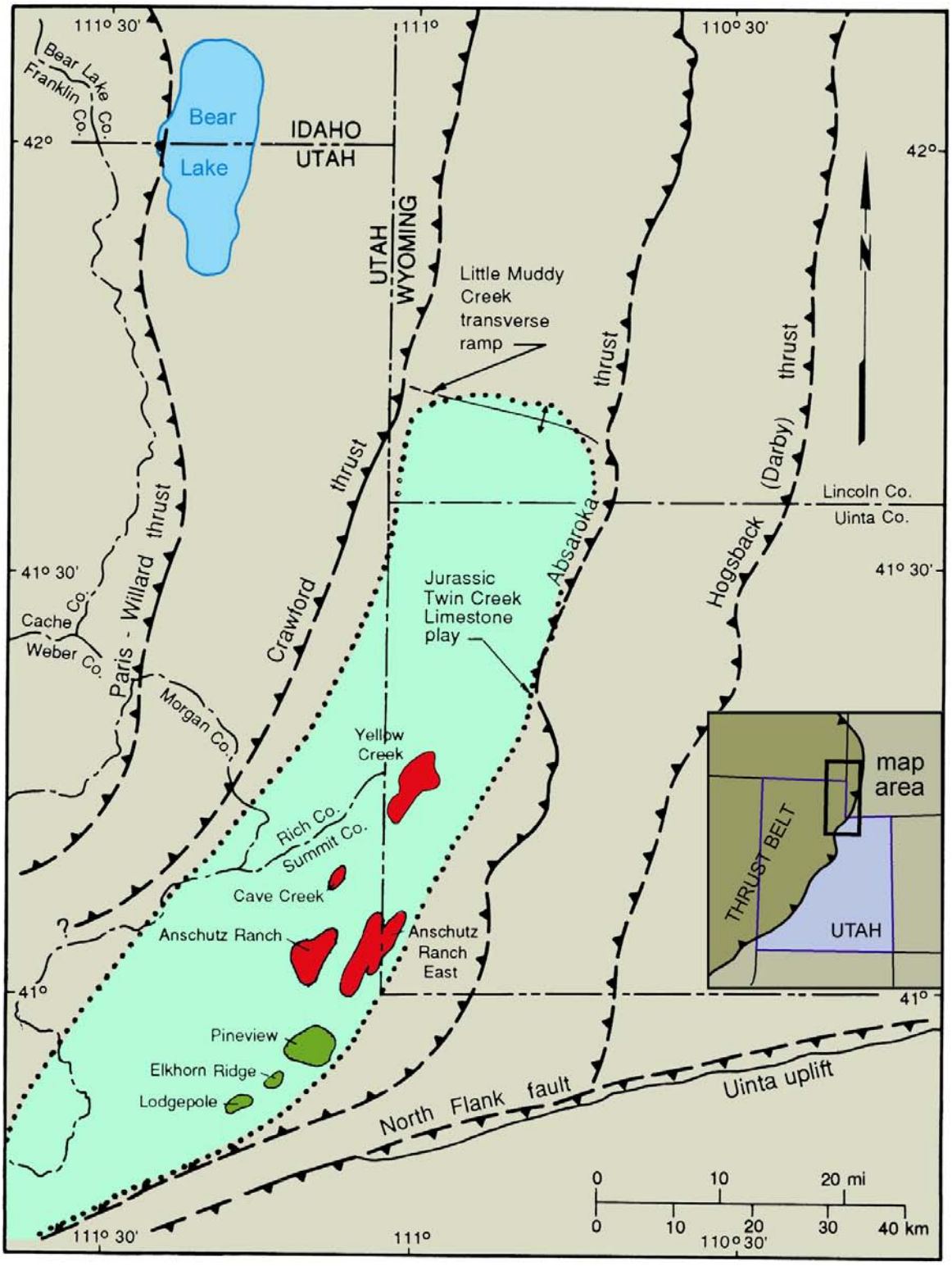


Figure 4-1. Location of reservoirs that produce oil (green) and gas and condensate (red) from the Jurassic Twin Creek Limestone, Utah and Wyoming; major thrust faults are dashed where approximate (teeth indicate hanging wall). The Twin Creek Limestone thrust belt play area is dotted (modified from Sprinkel and Chidsey, 1993).

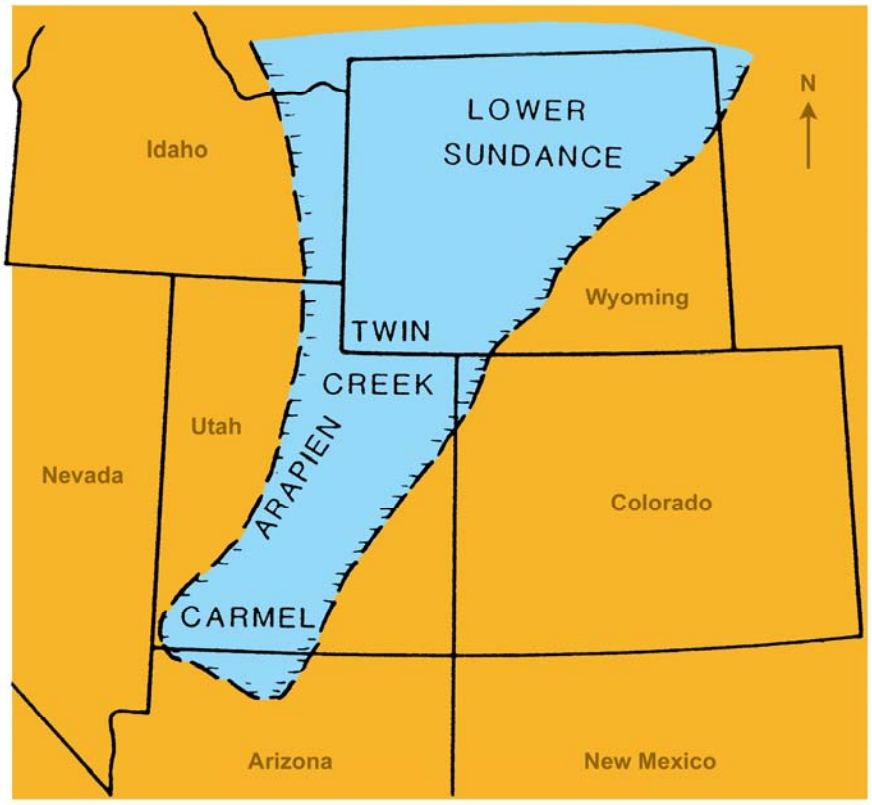


Figure 4-2. Generalized map of the Middle Jurassic marine invasion of the Sundance-Twin Creek-Arapien-Carmel seas from the north (modified from Kocurek and Dott, 1983; Hintze, 1993).



Figure 4-3. Typical Twin Creek Limestone, Watton Canyon Member, from the UPRR No. 3-3 well (section 3, T. 2 N., R. 7 E., SLBL&M, slabbed core from 8749 feet) showing finely laminated, carbonate mudstone deposited in backbank, low-energy brackish water environment. Note that essentially no porosity is present.

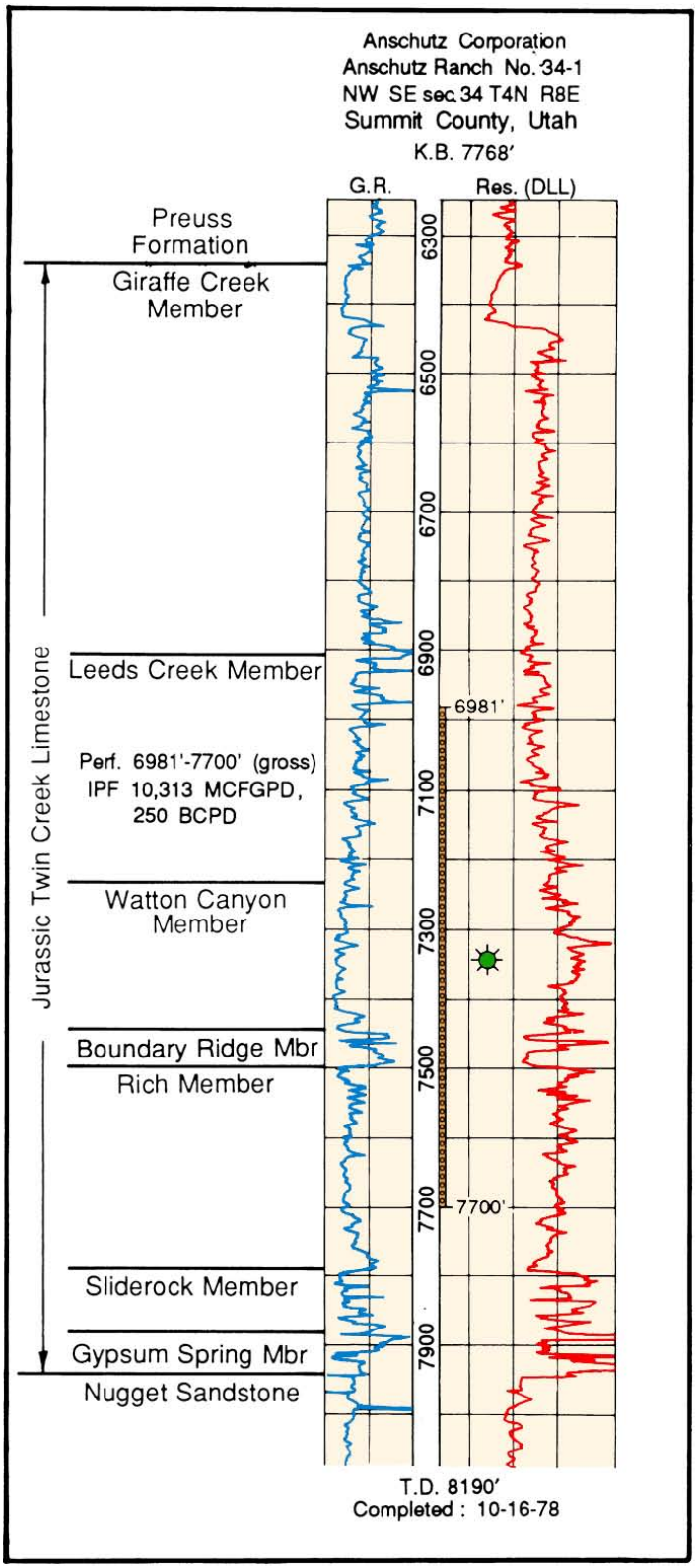


Figure 4-4. Typical gamma ray-resistivity log of the members of the Twin Creek Limestone, Anschutz Ranch field discovery well, Summit County, Utah.



Figure 4-5. Twin Creek Limestone reservoir rock, Watton Canyon Member, from the UPRR No. 3-3 well (section 3, T. 2 N., R. 7 E., SLBL&M, slabbed core from 8747 feet) showing highly fractured carbonate mudstone with open, bitumen-lined and calcite-filled fractures. Note zone of fossil hash at the base of the core.

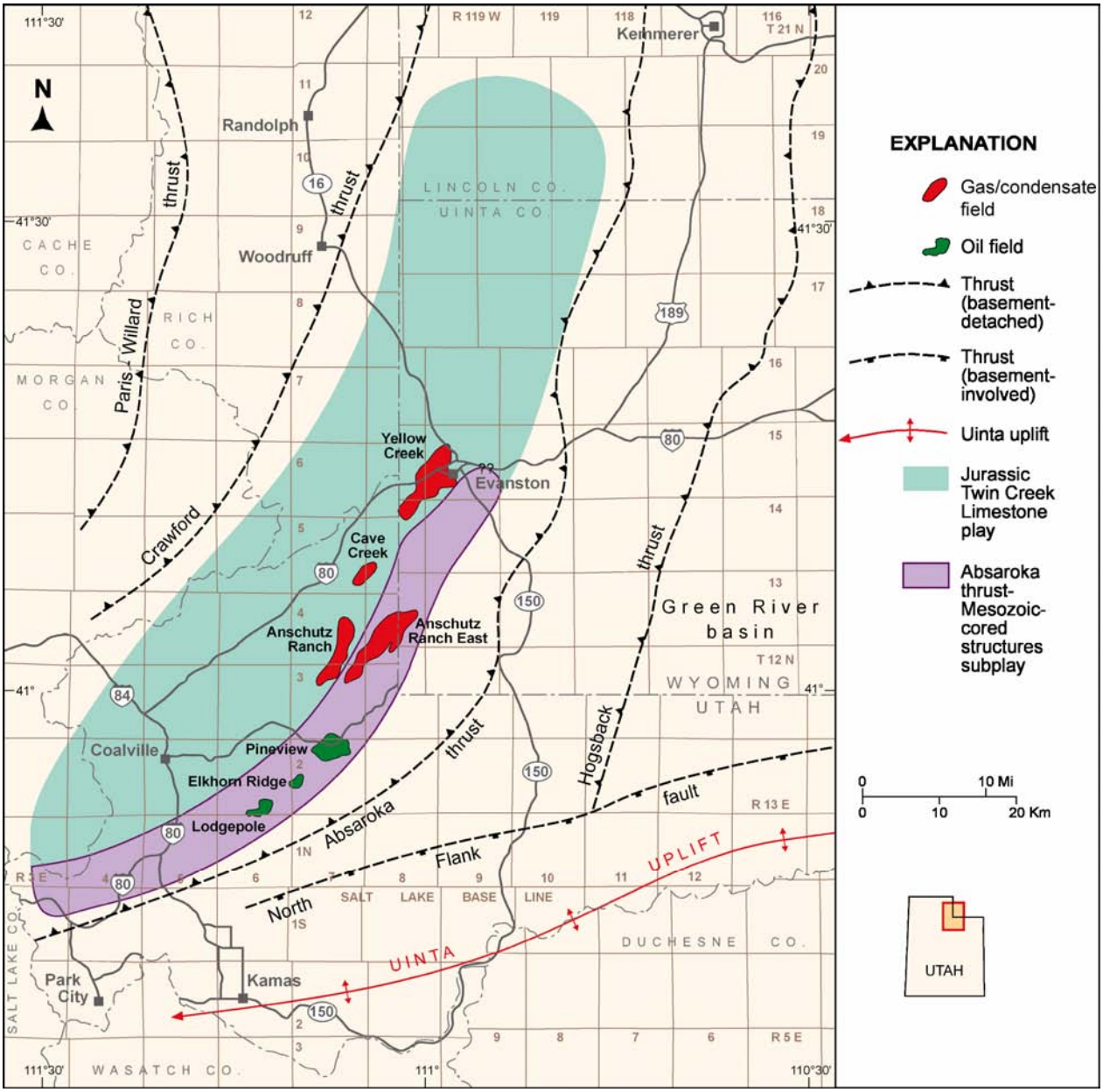


Figure 4-6. Location of the Twin Creek Limestone Absaroka thrust – Mesozoic-cored structures subplay, Summit County, Utah and Uinta County, Wyoming. Northern extent of the subplay is unknown.

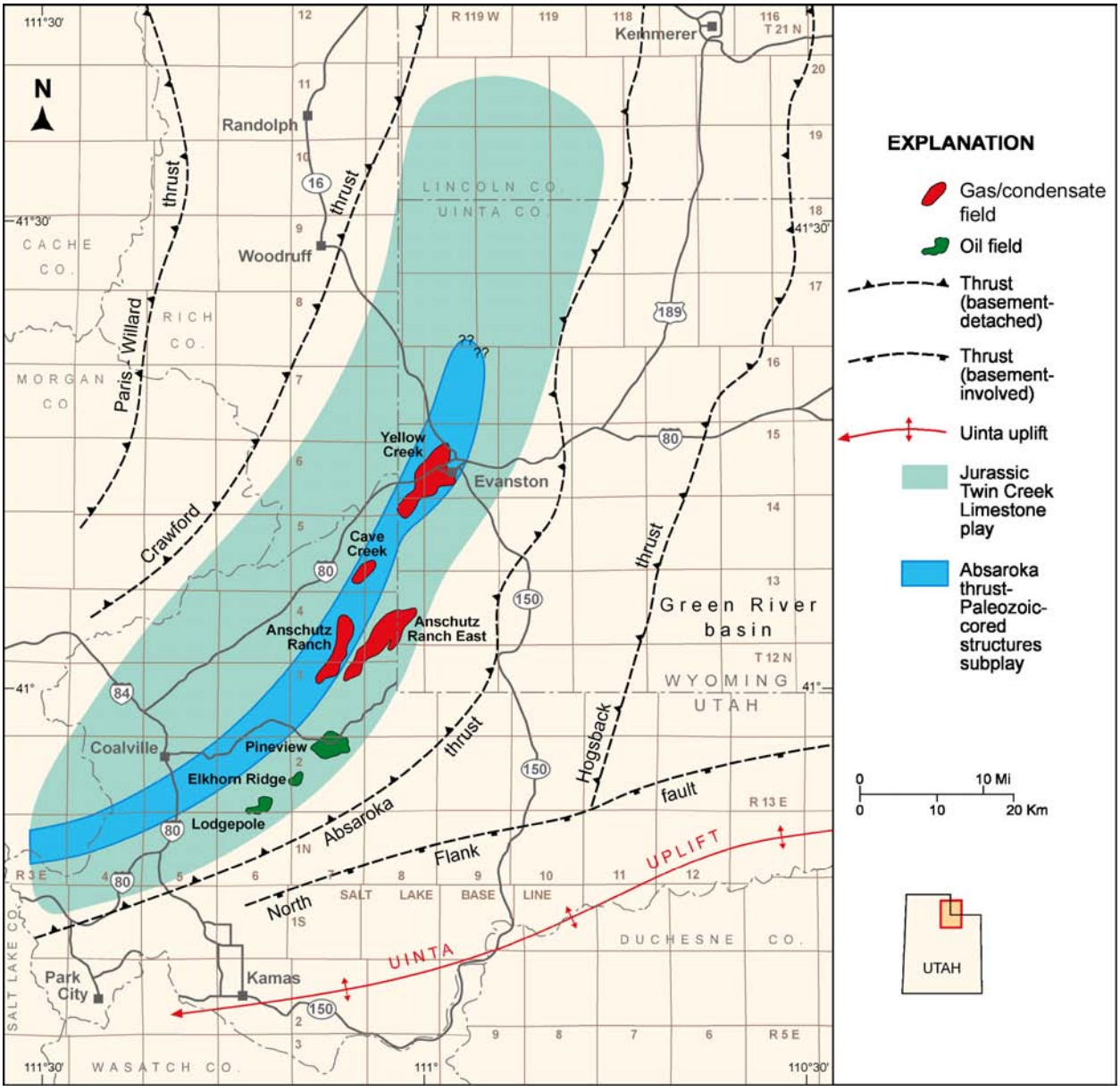


Figure 4-7. Location of the Twin Creek Limestone Absaroka thrust – Paleozoic-cored structures subplay, Summit County, Utah and Uinta County, Wyoming. Northern extent of the subplay is unknown.

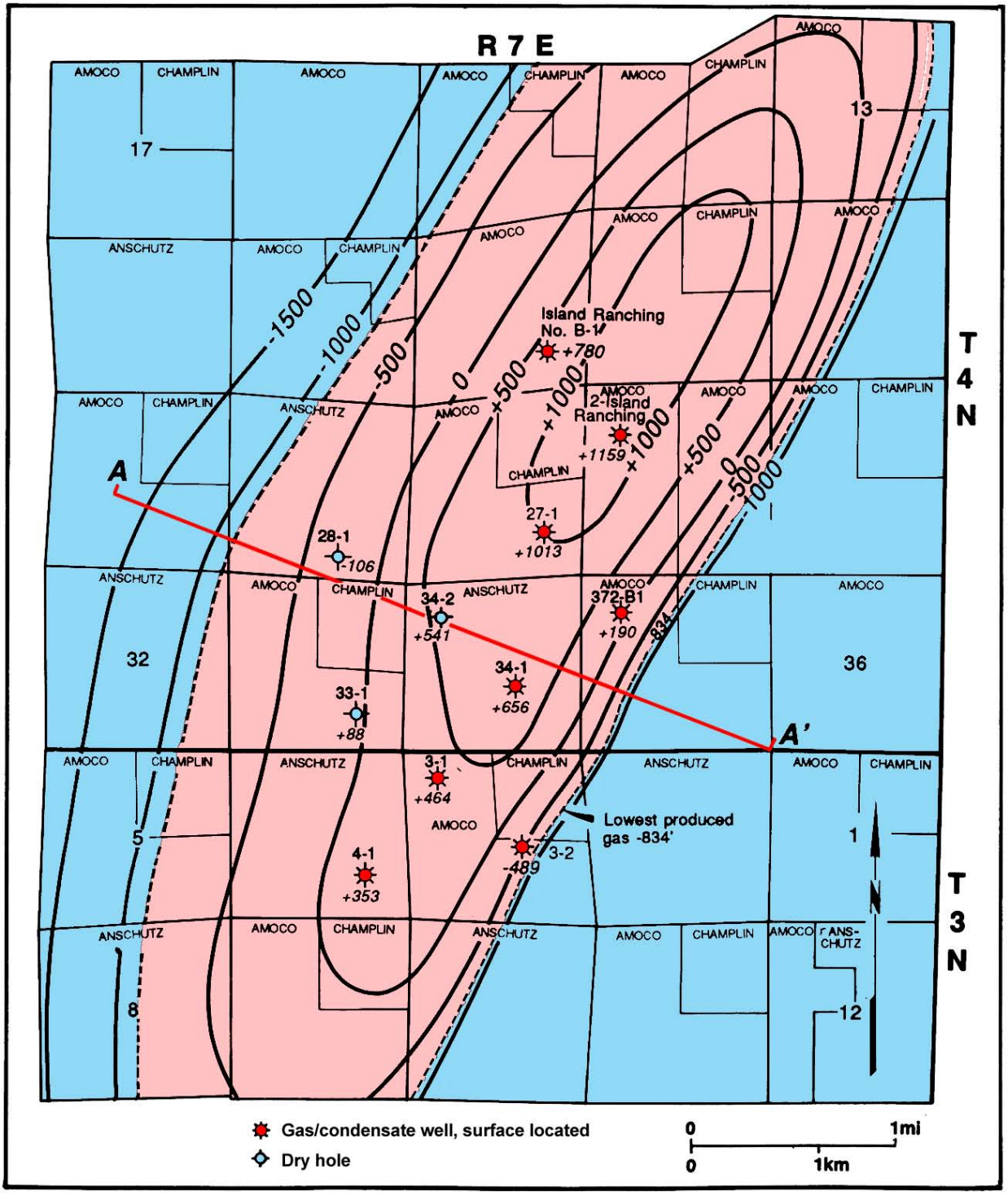


Figure 4-8. Structure contour map of the top of the Twin Creek Limestone, Anschutz Ranch field, Summit County, Utah, typical of the geometry of Paleozoic-cored structures in the Jurassic Twin Creek Limestone thrust belt play. Gas and condensate are trapped by the doubly plunging, asymmetric anticline in the hanging wall of the Absaroka thrust system. Modified from Utah Division of Oil, Gas and Mining (1980b). Cross section A-A' shown on figure 4-9.

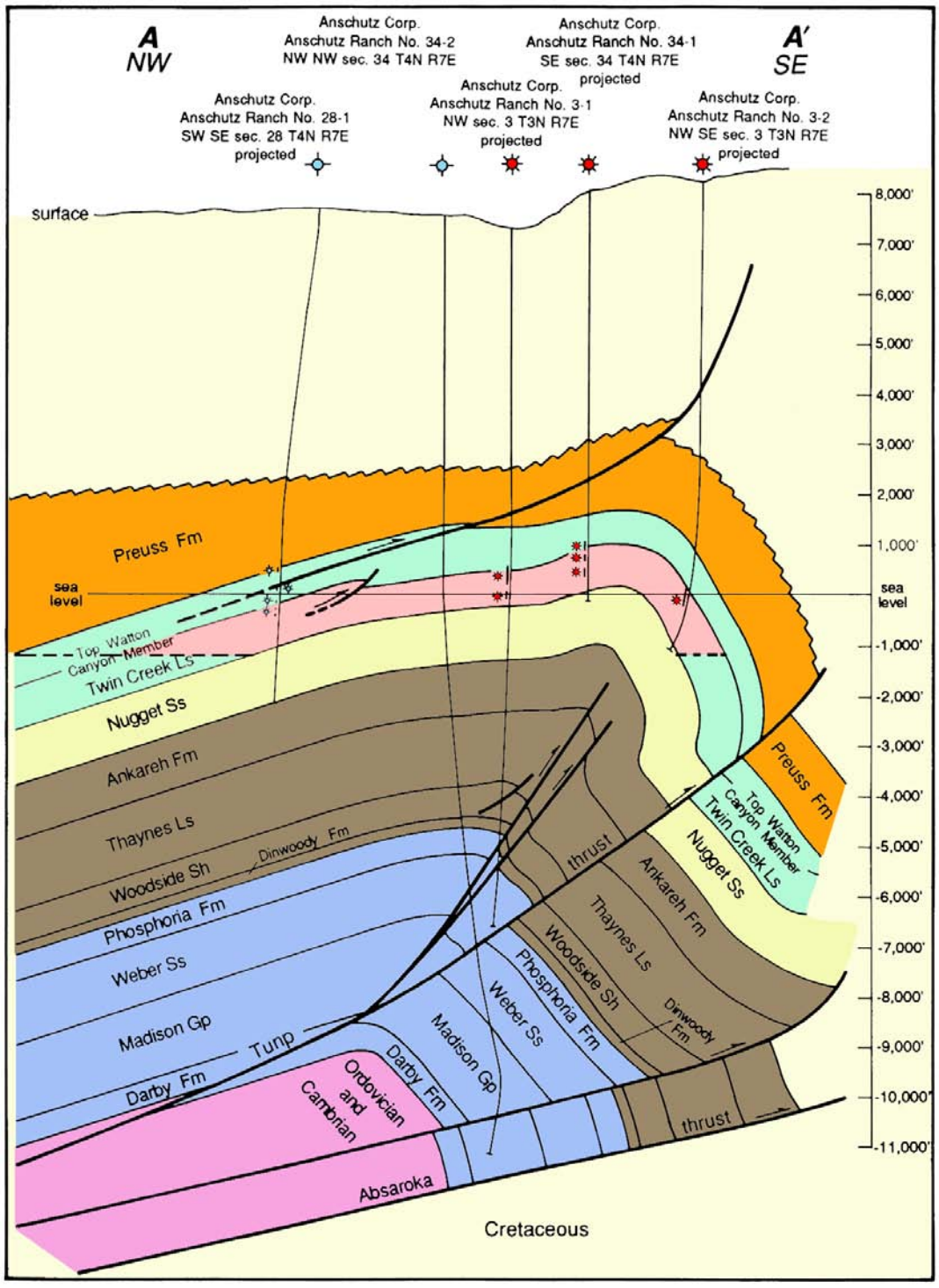


Figure 4-9. Northwest-southeast cross section through the Anschutz Ranch structure. Line of section shown on figure 4-8. Cretaceous formations in the footwall of the Absaroka thrust system charge the overlying, highly fractured limestone beds of the Twin Creek Limestone with gas, condensate, and oil. Modified from Utah Division of Oil, Gas and Mining (1980c).

Table 4-1. Geologic, reservoir, and production data for fields in the Jurassic Twin Creek Limestone thrust belt play. Data from Petroleum Information (1981), Bruce (1988), Benson (1993a, 1993b), Cook and Dunleavy (1993), Sprinkel and Chidsey (1993), Utah Division of Oil, Gas and Mining (2008, and well records), and Wyoming Oil & Gas Conservation Commission (2008).

State	County	Field	Discovery Date	Active Producers	Abandoned Producers	Acres	Spacing (acres)	Pay (feet)	Porosity (%)	Perm. (mD)	Temp. (°F)	Initial Reservoir Pressure (psi)	Average Monthly Production		Cumulative Production	
													Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (BCF)
Utah	Summit	Anschutz Ranch	1978	5	7	2880	320	520	3	30	124	2660	425	34,230	701,323	46.569
Utah	Summit	Anschutz Ranch East	1991	1	0	80	80	322	4	NA	188	NA	143	3477	1002	0.024
Utah	Summit	Cave Creek	1983	0	3	1600	640	20	4	NA	125	2396	0	0	133,208	9.761
Utah	Summit	Elkhorn Ridge	1977	3	3	480	40	90	3	7	168	3854	22	0	1,837,067	0.849
Utah	Summit	Lodgepole	1976	4	4	640	160	75	3	7	168	4474	386	0	1,675,009	0.520
Utah	Summit	Pineview	1975	7	12	2080	80	200	2	3.8	210	4200	7451	17,044	8,731,711	10.544
Wyoming	Uinta	Yellow Creek	1976	1	27	7840	160	170	2	1.3	117	2555	13	2237	2,029,877	24.777

NA = Not Available

CHAPTER 5
JURASSIC NAVAJO SANDSTONE HINGELINE PLAY

Thomas C. Chidsey, Jr., and Douglas A. Sprinkel,
Utah Geological Survey

Introduction

Central Utah has seen petroleum exploration for over 50 years because explorationists viewed the geology as a natural extension of successful plays in the Utah-Wyoming-Idaho salient of the Sevier (Cordilleran) thrust belt to the north (figures 1-3 and 2-2). Early efforts tested anticlines identified from surface mapping and seismic reflection data. The map on figure 5-1 represents about 276 square townships. Since 1918, the area had fewer than 120 wells drilled, which means only one well was drilled per every two townships, or one well per about 72 square miles (186 km^2). The first well in the region was drilled in 1918. No wells were drilled during the Great Depression years of the 1930s, but increases followed each decade through the 1980s (figure 5-2). During the late 1970s to early 1980s, companies drilled thrust belt-style structures in the wake of the 1975 Pineview discovery in northern Utah (figure 1-3A), and because of a significant increase in oil prices from the Arab oil embargo and the Iranian revolution. Drilling peaked in 1985 but decreased thereafter due to a drop in oil prices and the high risk and costs associated with exploration in the Hingeline area. Although early efforts failed to find commercial hydrocarbon deposits, companies confirmed the area was similar in structural style, reservoir types, and timing to the productive thrust belt to the north. The lack of Cretaceous hydrocarbon source beds below the thrust structures seemingly was to blame for the early exploration failures; however, oil and gas shows were commonly noted in Mississippian, Permian, Triassic, and Jurassic rocks. The 2004 discovery of Covenant field (figure 1-3B) by Wolverine Gas and Oil Company in the Jurassic Navajo Sandstone along the Sanpete-Sevier Valley antiform changed the oil development potential in the central Utah thrust belt from hypothetical to proven.

The Jurassic Navajo Sandstone Hingeline play extends 200 miles (320 km) south-southwest starting 20 miles (30 km) north of Provo, Utah, and extending to southwestern Sevier County; it thins from 25 miles (40 km) wide in the north to zero in the south (figure 1-3B). It lies due south of the Utah-Wyoming-Idaho salient and straddles the boundary between the eastern Basin and Range (eastern Millard, Juab, and Utah Counties) and High Plateaus (central Sevier and Sanpete Counties) physiographic provinces. The Jurassic Navajo Sandstone Hingeline play area represents the maximum extent of petroleum potential in the geographical area as defined by producing reservoirs, hydrocarbon shows, and untested hypotheses. The attractiveness of the Jurassic Navajo Sandstone Hingeline play (and other thrust belt plays) to the petroleum industry depends on the likelihood of successful development, reserve potential, pipeline access, drilling costs, oil and gas prices, and environmental concerns. When evaluating these criteria, certain aspects of the Navajo play may meet the exploration guidelines of major oil companies while other aspects meet the development guidelines of small, independent companies.

Prospective drilling targets in the Jurassic Navajo Sandstone Hingeline play are delineated using high-quality two-dimensional (2-D) and, in the near-future, three-dimensional (3-D) seismic data, 2-D forward modeling/visualization tools, well control, dipmeter information, high-

quality surface geologic maps, and detailed analyses of structural geometry (Meneses-Rocha and Yurewicz, 1999; Schelling and others, 2007). Incremental restoration of balanced cross sections is one of the best methods to assess trap geometry (Meneses-Rocha and Yurewicz, 1999). Several techniques can be used to determine the timing of structural development, petroleum migration, and entrapment, and to decipher fill and spill histories. These techniques include illite age analysis, apatite fission track analysis, and use of fluid inclusions (Meneses-Rocha and Yurewicz, 1999).

Depositional Environment

In Early Jurassic time, Utah had an arid climate and lay 15º north of the equator (Smith and others, 1981). The Navajo Sandstone and age-equivalent rocks were deposited in an extensive dune (erg) field (eolian environment) which extended from present-day Wyoming to Arizona (figure 3-3), and was comparable to the Sahara desert in North Africa or the Alashan area of the Gobi desert in northern China. The source of the sand was perhaps the Pennsylvanian Quadrant Quartzite in Montana, or possibly even as far away as the Appalachian area in the eastern U.S., based on zircon similarities (Rahl and others, 2003). The eolian deposits included dunes, interdunes, and sand sheets. Navajo dunes were large to small, straight-crested to sinuous, coalescing, transverse barchanoid ridges as suggested by large-scale cross-bedding (Picard, 1975; Fryberger, 1990). Regional analyses of the mean dip of dune foreset beds indicate paleocurrent and paleowind directions were dominantly from the north and northwest (figure 3-3) (Kocurek and Dott, 1983).

In addition to a "sea" of wind-blown sand dunes, the Navajo erg system included interdune playas and oases. A high water table produced oases; deposition occurred when spring and lakes existed for relatively long periods of time. The high water table also resulted in early soft-sediment deformation in overlying dune sands (Sanderson, 1974; Doe and Dott, 1980). Some Navajo interdunes were erosional (deflation) areas associated with running water, such as a wadi or desert wash (a wadi is a usually dry streambed or channel in a desert region). Sand sheets represented by low-relief, poorly drained, vegetated or gravel pavement deposits were also common (Lindquist, 1988). These areas acted as sand transport surfaces.

Stratigraphy and Thickness

The Navajo Sandstone is 740 to 1700 feet (250-570 m) thick in the play area (Hintze, 1993) and has a characteristic geophysical log response (figure 5-3). At Covenant field, the Navajo is divided into lower, middle, and upper units based on core and geophysical log analysis (figure 5-3). The lower and upper units have subtle but distinct characteristic geophysical log responses; the middle unit has a high gamma-ray profile recognized on other logs regionally and can be tied to the Navajo outcrop.

The central Utah thrust belt is divided into eastern, central, and western areas based on stratigraphy (figures 5-4 and 5-5). In Covenant field (central area) the Navajo Sandstone is overlain by the Jurassic Twin Creek Limestone and underlain by the Triassic Chinle Formation. The depth to the Navajo in Covenant field is 5840 feet (1780 m).

Lithology and Fracturing

The productive part of the lower unit of the Navajo Sandstone is about 240 feet (80 m) thick; the upper unit is about 200 feet (70 m) thick. These units are characterized by the large-scale, trough, planar, or wedge-planar cross-beds (35 to 40º) commonly recognized as classical eolian dune features (figure 5-6); contorted bedding, wind ripples, and small-scale cross-beds are also common (Sanderson, 1974). Dune lithofacies from the brink to the toe of the dune slipface consist of (1) thin, graded, tabular grainfall laminae (rarely preserved), (2) thick, subgraded avalanche laminae, and (3) thin, tightly packed, reworked ripple strata at the dune toe (Lindquist, 1983). Massive, homogenous beds with no distinct sedimentary structures or laminations are also recognized in the Navajo and were probably formed by water-saturated sand (Sanderson, 1974).

In general, the lower and upper units of the Navajo consist of very well to well-sorted, very fine to medium-grained (1/16 mm to ½ mm), subangular to subrounded sand or silt grains cemented by carbonate cement. However, some intervals show a bimodal grain-size distribution representing silty laminae between sand beds (figure 5-7). The typical sandstone is 97% white or clear quartz grains (usually frosted) with varying amounts of K-feldspar. Very little clay is present in the Navajo (Strickland and others, 2005).

The middle unit of the Navajo is a more heterogeneous, 50-foot-thick (17 m) interdunal section. This unit is characterized by low-angle to horizontal laminae or distorted bedding consisting of very fine to fine-grained, thin, poorly sorted sandstone, siltstone, and shale (figure 5-8). Horizontal stratification often contains silty laminae between beds. These beds may also display wind ripples or fluvial characteristics (scour). Interdunal fluvial characteristics indicate sheet flow or flooding events in a wadi while other deposits suggest wet playa or lacustrine conditions.

Fractures in the Navajo Sandstone consist of two types: (1) early, bitumen and gouge-filled, silica-cemented, impermeable fractures (figure 5-9), and (2) later, typically open (little gouge or cement), permeable fractures. The later fractures are related to fault-propagation folding during the Sevier orogeny after deep burial (Royce and others, 1975).

Hydrocarbon Source and Seals

The lack of good Cretaceous source rocks was blamed for early exploration failures in the central Utah thrust belt; however, oil and gas shows were common in Mississippian, Permian, Triassic, and Jurassic rocks. Although minor coaly beds are present in the Upper Cretaceous rocks in the eastern part of central Utah, the Cretaceous strata are more fluvial and nonmarine to the west and probably are only gas-prone. Therefore, unlike the producing structures of the thrust belt in northern Utah and southwestern Wyoming, the structures and faults of central Utah are not in contact with high-quality marine Cretaceous source rocks.

With the discovery of Covenant field, a viable source rock is proven in the central Utah thrust belt; however, the exact geochemical correlation between the oil produced at Covenant and the formation acting as the source rock has not been demonstrated. Several source candidates are present in the region. They include the Mississippian Delle Phosphatic Member of the Deseret Limestone and equivalent formations (figure 5-10) (Sandberg and Gutschick, 1984), the Mississippian Chainman Shale (Poole and Claypool, 1984; Sandberg and Gutschick, 1984; Wavrek and others, 2005) (figures 5-10 and 5-11), the Mississippian Long Trail Shale of

the Great Blue Limestone (Poole and Claypool, 1984), the Mississippian Doughnut Formation (Swetland and others, 1978), the Mississippian-Pennsylvanian Manning Canyon Shale (Swetland and others, 1978; Poole and Claypool, 1984), and the Permian Park City/Phosphoria Formation (Claypool and others, 1978; Sprinkel and others, 1997; Peterson, 2000, 2001). Total organic carbon for some units within these rocks is 15%. The regional distribution of these formations is shown by Peterson (2001).

What we do know about the possible correlation between the Covenant field oil and its source is based on limited or negative evidence. A graph (figure 5-12) plotting stable carbon-13 isotopes of saturated versus aromatic hydrocarbons from the Covenant field oil with other well-documented Mississippian and Permian oils shows the Covenant oil was derived from marine source beds. This is based on its canonical variable (CV) of less than 0.47 (Sofer, 1984). We eliminated known marine Cretaceous source beds because they are not found in central Utah and the geochemistry of the Covenant oil is similar to known Paleozoic oils that have been correlated to source beds in the region (table 5-1). Furthermore, we believe we can eliminate the Mississippian Chainman Shale and the Permian Phosphoria Formation as possible sources based on a graph plotting canonical variable (CV) versus pristine/phytane values (figure 5-13). Thus, the Covenant field oil is likely derived from a Carboniferous source (see Wavrek and others, 2005, 2007).

As stated earlier, thrusting in this area is Cretaceous to early Tertiary in age. Most of the hydrocarbon generation and migration probably occurred during this period; however, some could have started as early as Permian or Triassic time in the older Paleozoic rocks and as late as Tertiary time in Mesozoic rocks. Hydrocarbons were then expelled and subsequently migrated into the overlying traps, primarily along fault planes or through porous Paleozoic and Mesozoic carrier beds. Late Tertiary extension in this area may have disrupted the traps more than in the productive thrust belt of northern Utah and southwestern Wyoming.

Oil migrating from the Mississippian Chainman Shale in western Utah requires a post-Sevier-orogeny, long-distance migration, and must have circumvented the Sevier arch where no Mississippian rocks are present. Potential hydrocarbon sources in the Mississippian Delle Phosphatic Member and Mississippian-Pennsylvanian Manning Canyon Shale (containing 2% to 15% total organic content) would have to have been generated outside the Pennsylvanian-Permian Oquirrh basin to the north where they would have been deeply buried and too highly "cooked," resulting in the migration of hydrocarbons prior to the formation of the thrust belt traps. In central Utah, the question remains whether these rocks have been buried deep enough on the western parts of the hanging walls of the thrust faults to generate hydrocarbons. However, at least as far east as the Paxton thrust (figure 1-3B), the Mississippian section lies just below the basal décollement in the footwall where thrust loading could have generated hydrocarbons. Finally, just south of the Covenant field area, heat from Tertiary (Oligocene) volcanism may have provided an extra mechanism to stimulate hydrocarbon generation.

The principal regional seal for the Navajo producing zones consists of salt, gypsum, mudstone, and shale in the Jurassic Arapien Shale (figures 5-5 and 5-14). Shale intervals above the dense limestone members in the overlying Jurassic Twin Creek Limestone may serve as additional seals. Interdunal shale and mudstone within the Navajo Sandstone (figure 5-8), and splay and back thrust faults may act as local seals, barriers, or baffles to fluid flow.

Structure and Trapping Mechanisms

Internal deformation within large-scale thrust plates includes frontal and lateral duplex zones. The deformation front along the leading edge of these major thrusts, particularly the Paxton and Gunnison thrusts, includes complex back thrusting, tectonic-wedge formation, triangle zones, and passive-roof duplexing (Schelling and others, 2005). Fault-propagation/fault-bend folds and low-amplitude anticlines in both the hanging walls and footwalls of thrusts associated with these features may form multiple structural traps. These features are obscured by complex surface geology which includes (1) major folds (figure 5-15), (2) angular unconformities, (3) Oligocene volcanic rocks, (4) Basin and Range-age (Miocene-Holocene) listric(?) normal faulting, and (5) local diapirism. There is also potential for updip pinchout and isolated stratigraphic traps in the Mesozoic section.

The Gunnison thrust in the eastern play area is primarily a bedding-plane fault developed in weak mudstone and evaporite beds of the Arapien Shale. Thrust imbricates or imbricate fans above and antiformal stacks of horses forming a duplex below the Gunnison thrust create multiple, potential drilling targets (figure 2-8) (Villien and Kligfield, 1986). Jurassic extensional faults may be the key to hydrocarbon migration pathways and locating antiformal stacks that may contain traps along thrusts (Schelling and others, 2005; Strickland and others, 2005).

Covenant field (figure 1-3B), Sevier County, is located along the east flank of the Sanpete-Sevier Valley fold (figure 5-15). The Kings Meadow Ranches No. 17-1 discovery well (SE1/4NW1/4 section 17, T. 23 S., R. 1 W., SLBL&M) was drilled updip from two abandoned wells about 2 miles (3 km) to the north: the Standard Oil of California Sigurd Unit No. 1 (NE1/4SE1/4 section 32, T. 22 S., R. 1 W., SLBL&M) drilled in 1957, and the Chevron USA Salina Unit No. 1 (NE1/4NE1/4 section 33, T. 22 S., R. 1 W., SLBL&M) drilled in 1980. The Navajo Sandstone was encountered at subsea depths of –3390 feet (-1033 m) and -2973 feet (-906 m), respectively, in these wells. The dipmeter in the Salina Unit No. 1 well showed 16° structural dip to the northwest in the Navajo. This dip combined with seismic data indicate a structural high to the south. The Kings Meadow Ranches No. 17-1 well penetrated the Navajo at a subsea depth of -94 feet (-29 m).

The Covenant field trap is an elongate, symmetric, northeast-trending fault-propagation/fault-bend anticline (figure 5-16), with nearly 800 feet (270 m) of structural closure with a 450-foot (150 m) oil column (Strickland and others, 2005; Chidsey and others, 2007). The Navajo oil-filled reservoir covers about 960 acres (390 ha). The structure formed above a series of splay thrusts in a passive roof duplex along the Gunnison thrust and west of a frontal triangle zone within the Arapien Shale (figure 5-17). The Twin Creek Limestone and Navajo Sandstone are repeated due to an east-dipping back-thrust detachment within the structure. This back thrust forms a hanging-wall cutoff along the west flank and north-plunging nose of the fold. Only the Navajo in the hanging wall of the back thrust (and possibly the Twin Creek) is productive.

Reservoir Properties

The Navajo has heterogeneous reservoir properties because of (1) cyclic dune/interdune lithofacies with better porosity and permeability in certain dune morphologies, (2) diagenetic effects, and (3) extensive fracturing. These characteristics can be observed in outcrops around the play area (figure 1-3B). Genetic units of eolian sandstone deposits are separated by 1st-order

bounding surfaces formed by interdune deposits or major diastems. Internal bounding surfaces are also found within dune cross-beds (Ahlbrandt and Fryberger, 1982; Fryberger, 1990; Grammer and others, 2004). Stacking surfaces or 2nd-order bounding surfaces (superposition surfaces) within a single genetic unit can divide the cross-strata of two dunes and are formed by migrating dunes superimposed on the slipfaces of the underlying dunes (Fryberger, 1990; Grammer and others, 2004; Morris and others, 2005). Growth surfaces or 3rd-order bounding surfaces are high-angle reactivation surfaces dividing sets of ripple strata related to the advance of a single dune (Fryberger, 1990; Grammer and others, 2004). These bounding surfaces represent possible barriers or baffles to fluid flow, both vertically and horizontally, within the Navajo reservoir. Identification and correlation of the numerous bounding surfaces as well as recognition of fracture set orientations and types in individual Navajo reservoirs are critical to understanding their effects on production rates, petroleum movement pathways, directionally drilled well plans, and future pressure maintenance programs.

The average porosity for the Navajo Sandstone at Covenant field is 12% (Strickland and others, 2005; Chidsey and others, 2007); the average grain density is 2.651 g/cm^3 based on core-plug analysis. Sandstone exhibits significant secondary porosity in the form of fracturing. Permeabilities in the Navajo from the core data are upwards of 100 mD. The best permeability within Navajo dune deposits is along bounding surfaces (bedding planes), with preferred directions along the dip and strike of the individual slipfaces or lee faces (cross-beds) (figure 3-21; Lindquist, 1983). Porosity and permeability should be greatest in thickly laminated avalanche deposits (Hunter, 1977; Schenk, 1981). Navajo interdunes, as expected, have significantly poorer reservoir characteristics than the dune lithofacies and represent significant barriers to fluid flow. Plotting porosity versus permeability shows gradational changes in reservoir quality within the various dune lithofacies and transitional changes to interdune lithofacies (figure 5-18). Mapping dune lithofacies prior to a well completion identifies zones of maximum drainage effects (Strickland and others, 2005).

Diagenetic effects and fracturing can both reduce and enhance the reservoir permeability of the Navajo Sandstone. At Covenant field, there are only minor overgrowths of quartz. Some authigenic clay mineralization has occurred in the form of grain-coating, pore-bridging, and fibrous illite. Some ferroan(?) dolomite and fractured, corroded K-feldspar are also present (Strickland and others, 2005). Development of bitumen and gouge-filled, silica-cemented fractures locally reduce reservoir permeability. Dissolution of silicate minerals and the development of open fractures increase reservoir permeability.

Navajo Sandstone gross-pay thickness at Covenant field is 487 feet (148 m) and net-pay thickness is 424 feet (129 m), a net-to-gross ratio of 0.87 (Strickland and others, 2005). The Navajo reservoir temperature is 188ºF (87ºC). The average water saturation is 38%, and average produced water resistivity (R_w) is 0.279 ohm-m at 77ºF (25ºC) containing 26,035 total dissolved solids. Initial reservoir pressures average about 2630 pounds per square inch (18,134 kPa). The reservoir drive mechanism is a strong active water drive. Geophysical well logs show a transition zone in terms of water saturation above a very sharp oil/water contact (figure 5-3).

Oil Characteristics

Covenant field's Navajo oil is a dark brown, low-volatile crude. The API gravity of the oil is 40.5º; the specific gravity is 0.8280 at 60ºF (16ºC). The viscosity of the crude oil is 4.0 cst at 77ºF (25ºC) and the pour point is 2.2ºF (-16.5ºC). The average weight percent sulfur of

produced Navajo oil is 0.48; nitrogen content is 474 parts per million. Stable carbon-13 isotopes are -29.4‰ and -29.0‰ for saturated and aromatic hydrocarbons, respectively. The pristane/phytane ratio is 0.96 (Baseline DGSI, 2005).

Production

Covenant field produces oil and water (about 5 to 10%), and essentially no gas. Cumulative production as of January 1, 2008, was 2,611,688 bbls (415,258 m^3) of oil and 434,629 bbls (69,106 m^3) of water (Utah Division of Oil, Gas and Mining, 2008). Daily oil production averages over 6000 bbls (950 m^3) of oil and just over 1500 bbls (240 m^3) of water. Production steadily increased through July 2006 as new development wells and infrastructure were completed; a slight decline is shown beginning in August 2006 (figure 5-19). The field currently has 10 producing wells and one dry hole, drilled from two pads. The well spacing is about 40 acres (16 ha) within the Covenant unit. Original oil in place (OOIP) reserves are estimated at 100 million bbls (15.9 million m^3) (Chidsey and others, 2007). A 40 to 50% recovery of the OOIP may be achieved with efficient operations and completion techniques (Strickland and others, 2005).

Exploration Potential and Trends

The result of the Covenant discovery has been high prices and competition for available leases in the play, hundreds of miles of new seismic surveys over much of the play area, and new well permits to test various parts of the play. From 2004 through 2006, extensive two-dimensional (2-D) seismic acquisition was permitted and conducted within the play area. Companies may soon turn to three-dimensional seismic to define the crests of structures identified by 2-D seismic. The current high price of oil and the potential to discover other major, or even smaller, oil fields in this play makes the development potential of this play high during the next 15 years.

Exploration in the central Utah thrust belt will focus on Paleozoic-cored, blind, thrust structures east of the exposed Charleston-Nebo and Pahvant thrusts. Targets include anticlines associated with thrust imbricate and duplex structures, positioned near Jurassic extensional faults, in the Navajo Sandstone and other reservoirs such as the Permian Park City-Kaibab Formations, Triassic Moenkopi Formation, and Jurassic Twin Creek Limestone (figure 2-8).

Significant questions remain to be answered concerning the hydrocarbon source and migration history. The lack of any associated gas at Covenant field suggests the possibility that sediment or thrust-plate loading may have driven the gas off during hydrocarbon migration (D.A. Wavrek, Petroleum Systems International, Inc., verbal communication, 2005; Wavrek and others, 2005) or faults acting as baffles caused gas to migrate along different paths than oil. Thus, potential gas-charged traps may be present in the play area.

The potential for finding hydrocarbons may be considerably higher in the southern play area due to the proximity of the Oligocene-age Marysvale volcanic field and likely associated intrusions. High heat flow and igneous activity may have been an added contributor to hydrocarbon generation from Paleozoic source rocks in the area. However, it may also “over cooked” these source rocks or generated carbon dioxide from Paleozoic carbonate rocks.

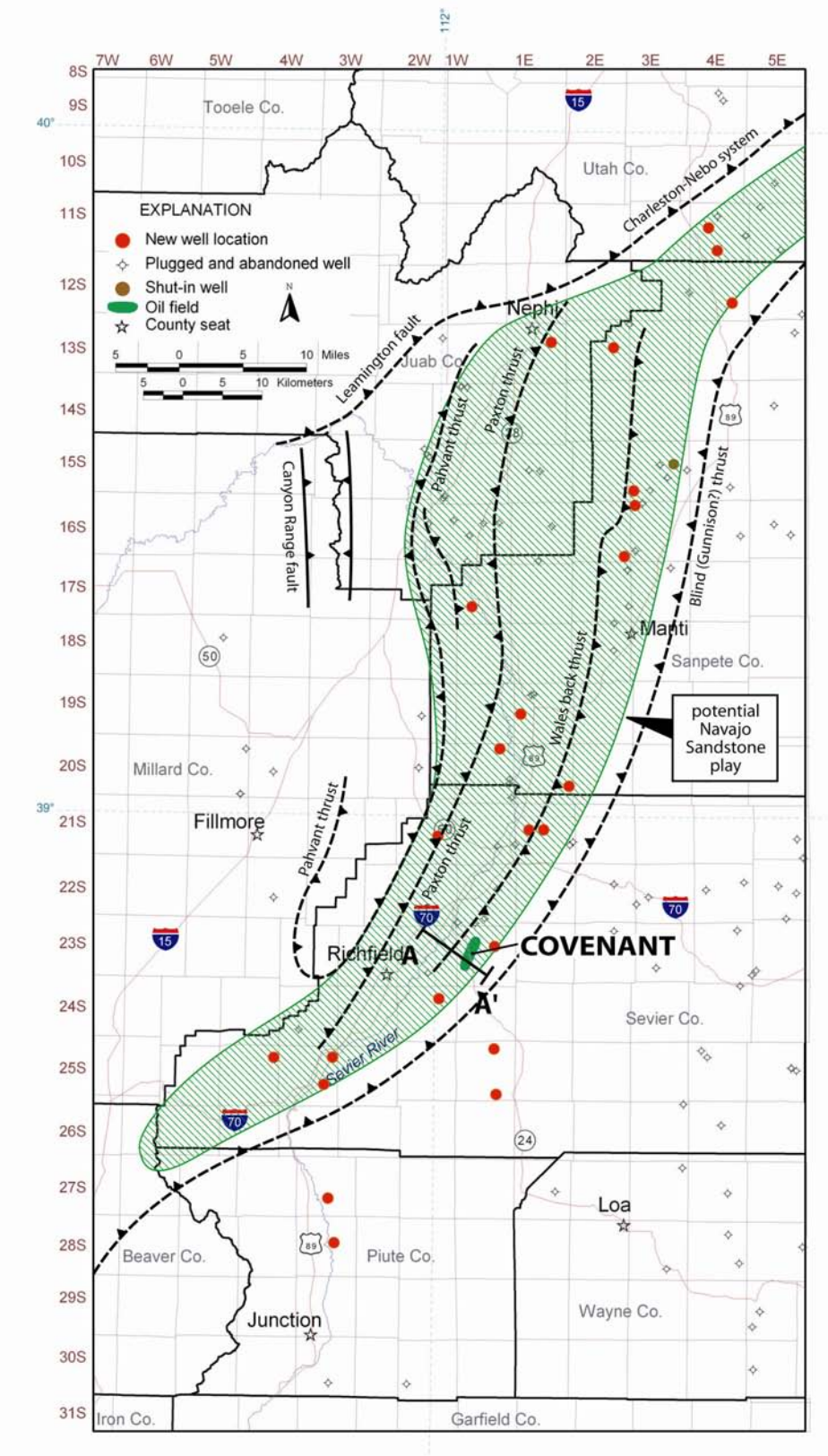


Figure 5-1. Jurassic Navajo Sandstone Hingeline play area showing regional exploratory well locations.

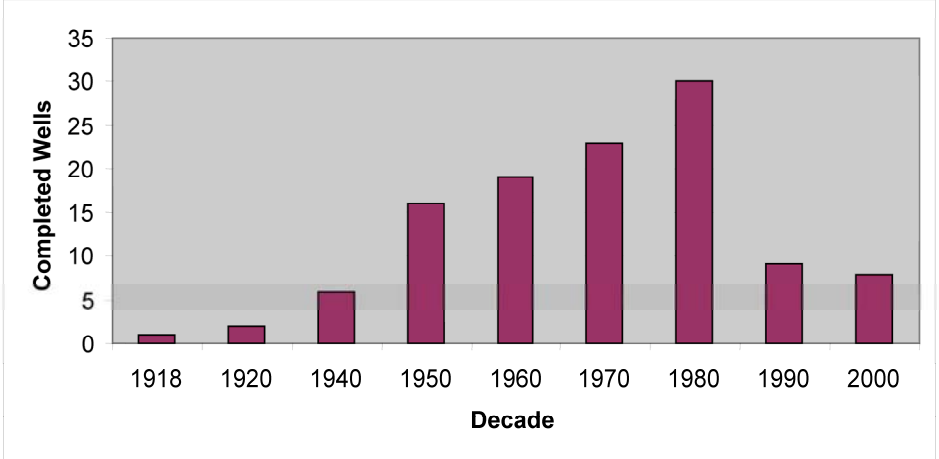


Figure 5-2. Exploration history of central Utah (Utah Division of Oil, Gas and Mining well files, http://www.ogm.utah.gov/).

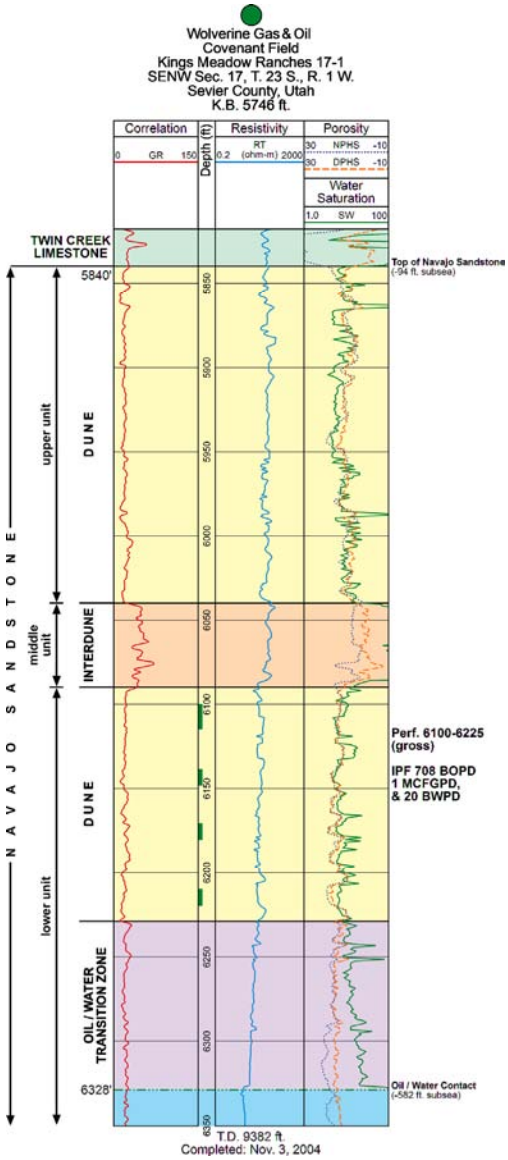


Figure 5-3. Typical combined gamma ray, resistivity, and neutron-density log of the Navajo Sandstone from the Kings Meadow Ranches No. 17-1 discovery well of Covenant field, Sevier County, Utah. The vertical green bars between depths of 6100 and 6225 feet on the log indicate producing (perforated) intervals.

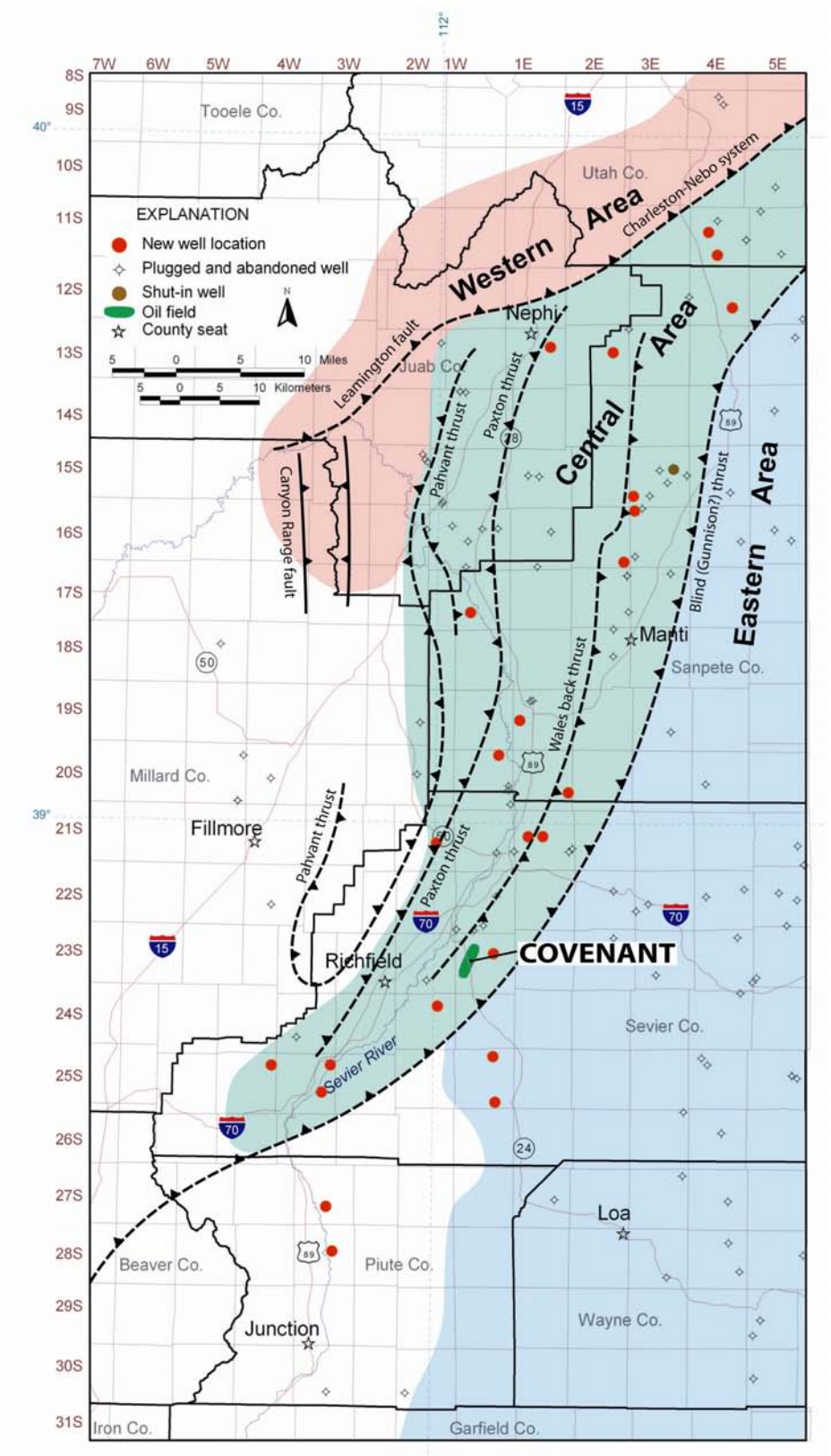


Figure 5-4. Eastern, central, and western areas of the central Utah thrust belt based on stratigraphy.

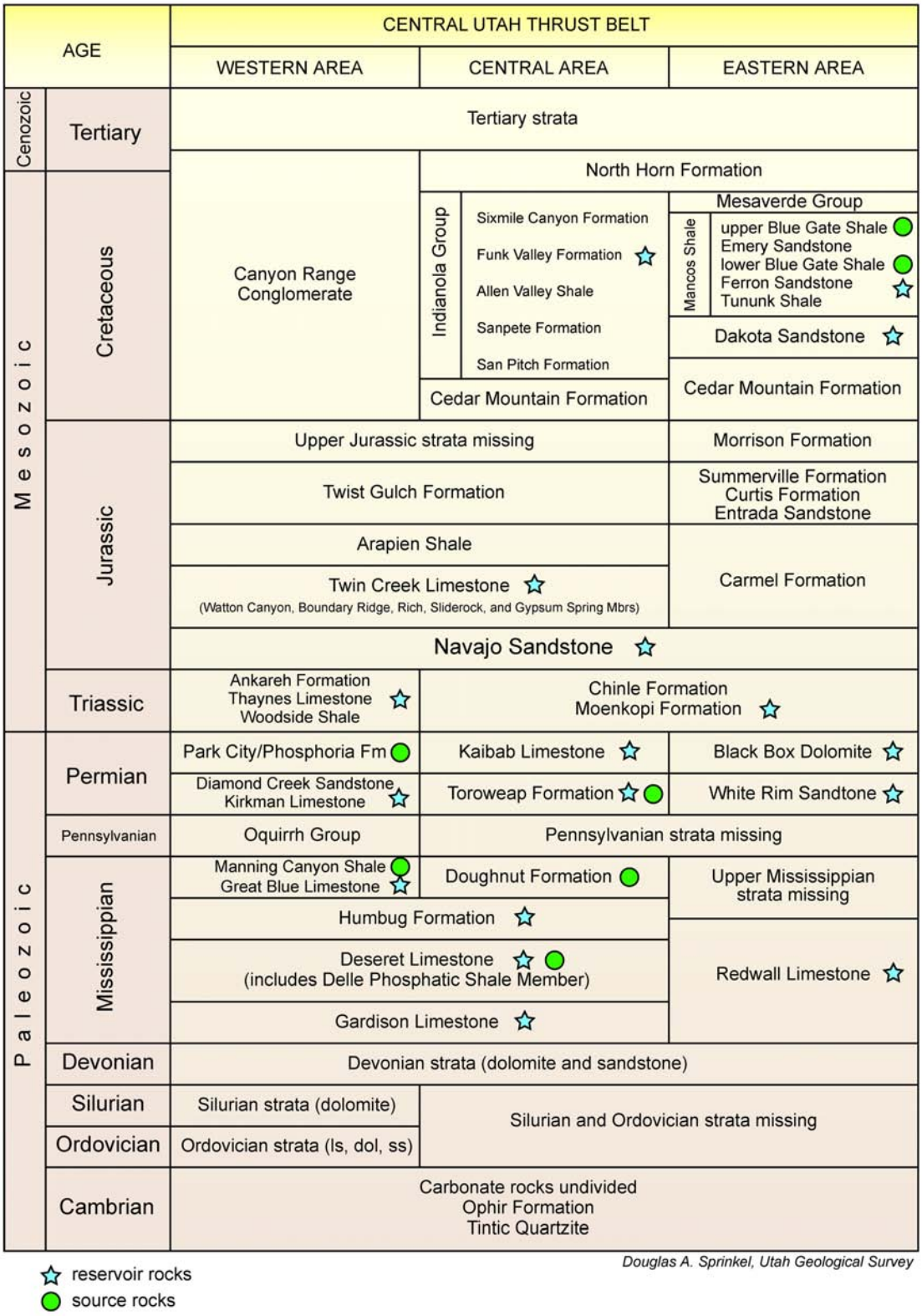


Figure 5-5. Detailed stratigraphic correlation chart showing Navajo Sandstone and other potential reservoir rocks as well as source rocks in central Utah (see figure 5-4 for location of eastern, central, and western areas).



Figure 5-6. Typical upper unit of the Navajo Sandstone, from the Kings Meadow Ranches No. 17-3 well (slabbed core from 6669 feet), Covenant field, showing cross-bedding in fine-grained sandstone deposited in a dune environment.

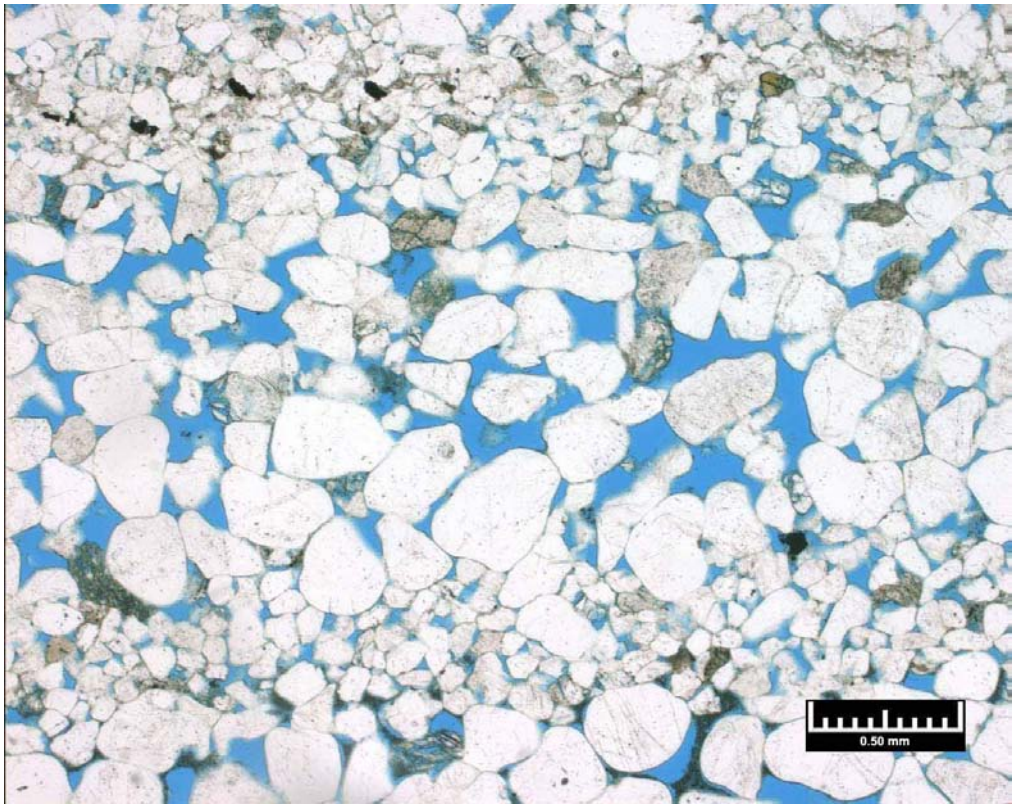


Figure 5-7. Representative photomicrograph (plane light) from the lower unit of the Navajo Sandstone showing bimodal distribution of subangular to subrounded quartz sand and silt. Note a few fractured and corroded K-feldspar grains are present. Blue space is intergranular porosity. Kings Meadow Ranches No. 17-3 well, 6773 feet, porosity = 14.8% permeability = 149 mD based on core-plug analysis. Courtesy of Wolverine Gas & Oil Corporation.



Figure 5-8. Typical middle unit of the Navajo Sandstone, from the Kings Meadow Ranches No. 17-3 well (slabbed core from 6752 feet), Covenant field, showing siltstone laminae and shale deposited in an interdune environment.



Figure 5-9. Early, bitumen and gouge-filled, silica-cemented, impermeable fractures, with slight offsets, in the Navajo Sandstone, from the Kings Meadow Ranches No. 17-3 well (slabbed core from 6776 feet), Covenant field.

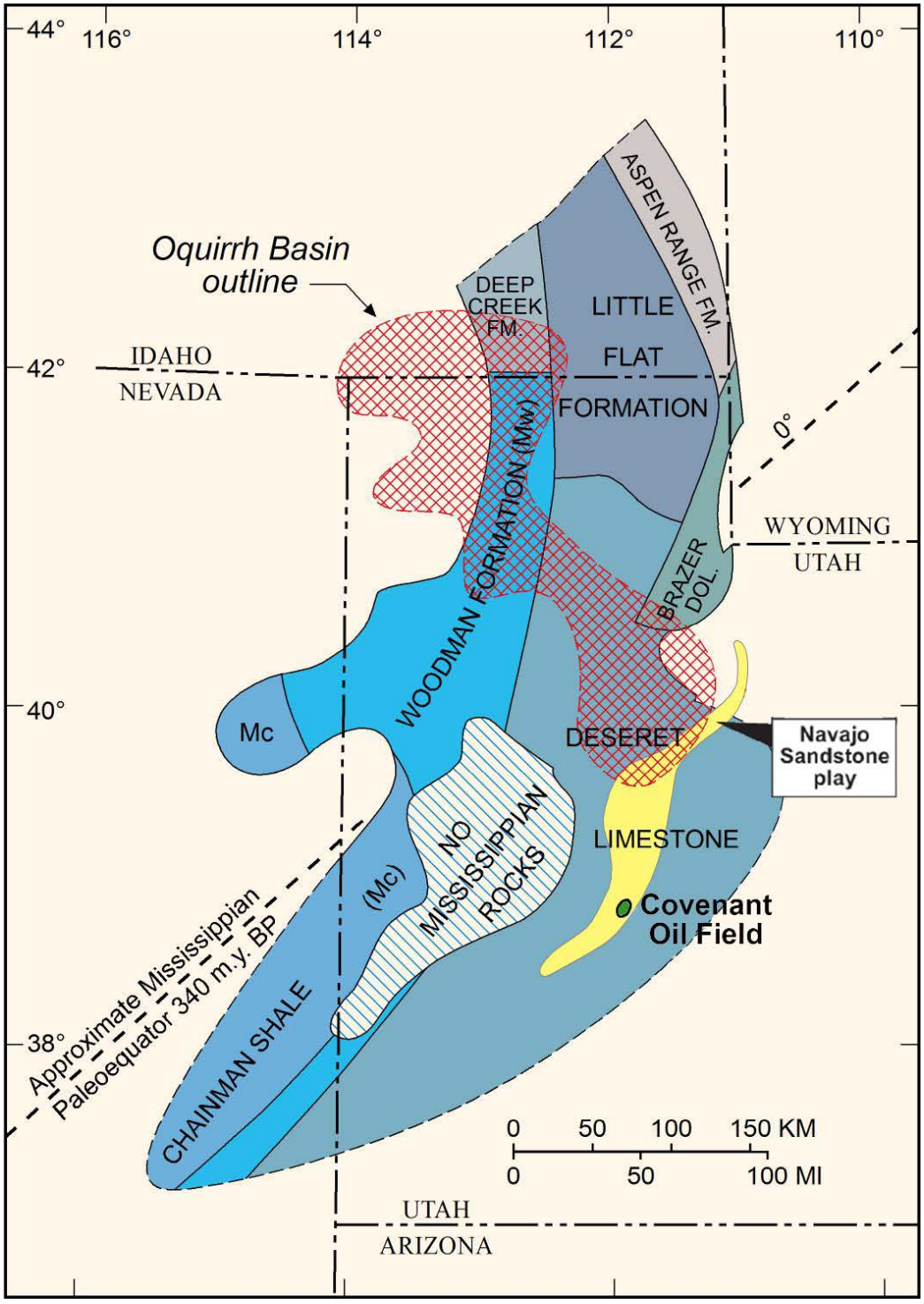


Figure 5-10. Location of the Mississippian Delle Phosphatic Member present in the Deseret Limestone and other Mississippian formations (modified from Sandberg and Gutschick, 1984).

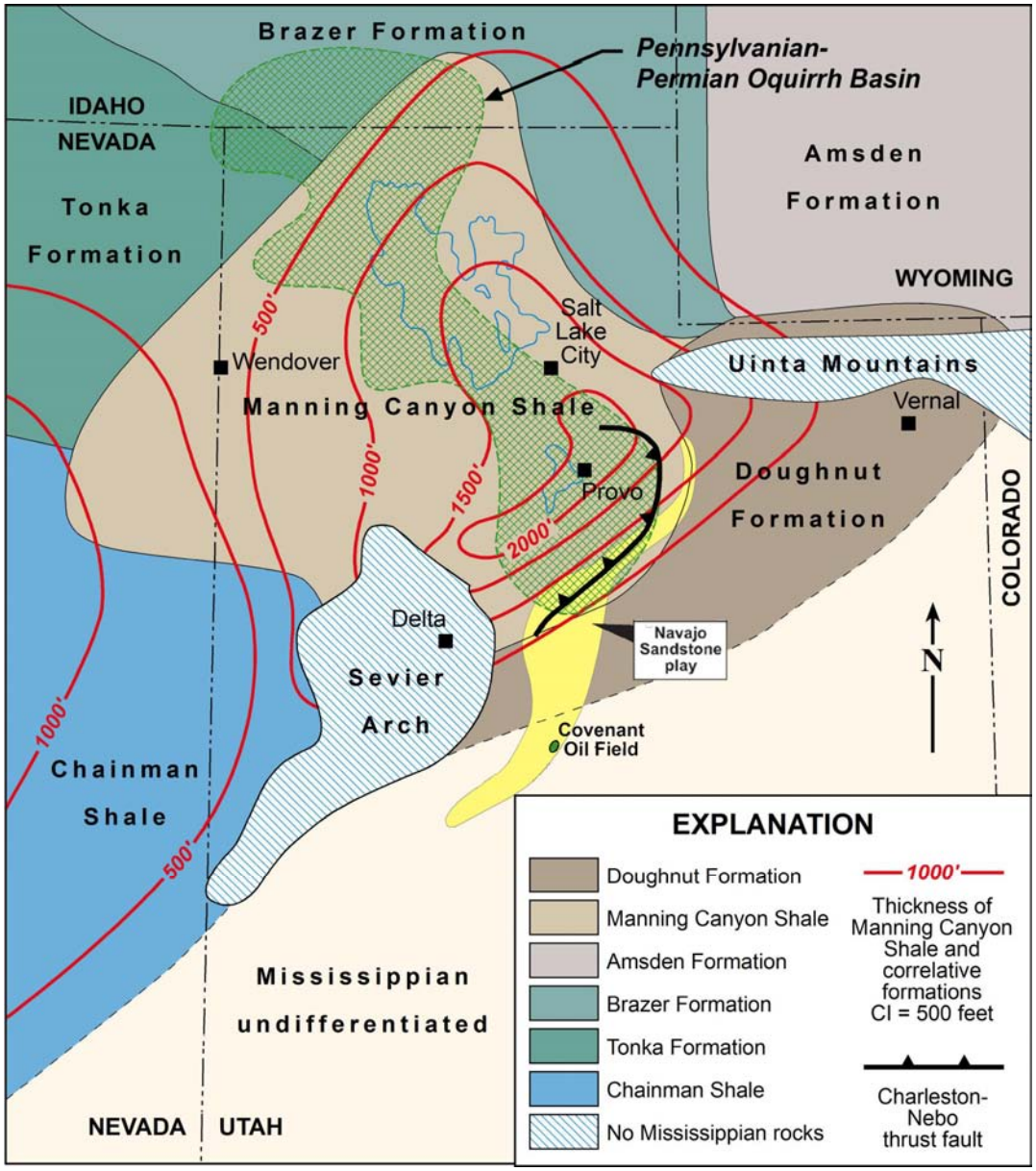


Figure 5-11. Location and thickness of the Manning Canyon Shale and correlative formations (modified from Moyle, 1958).

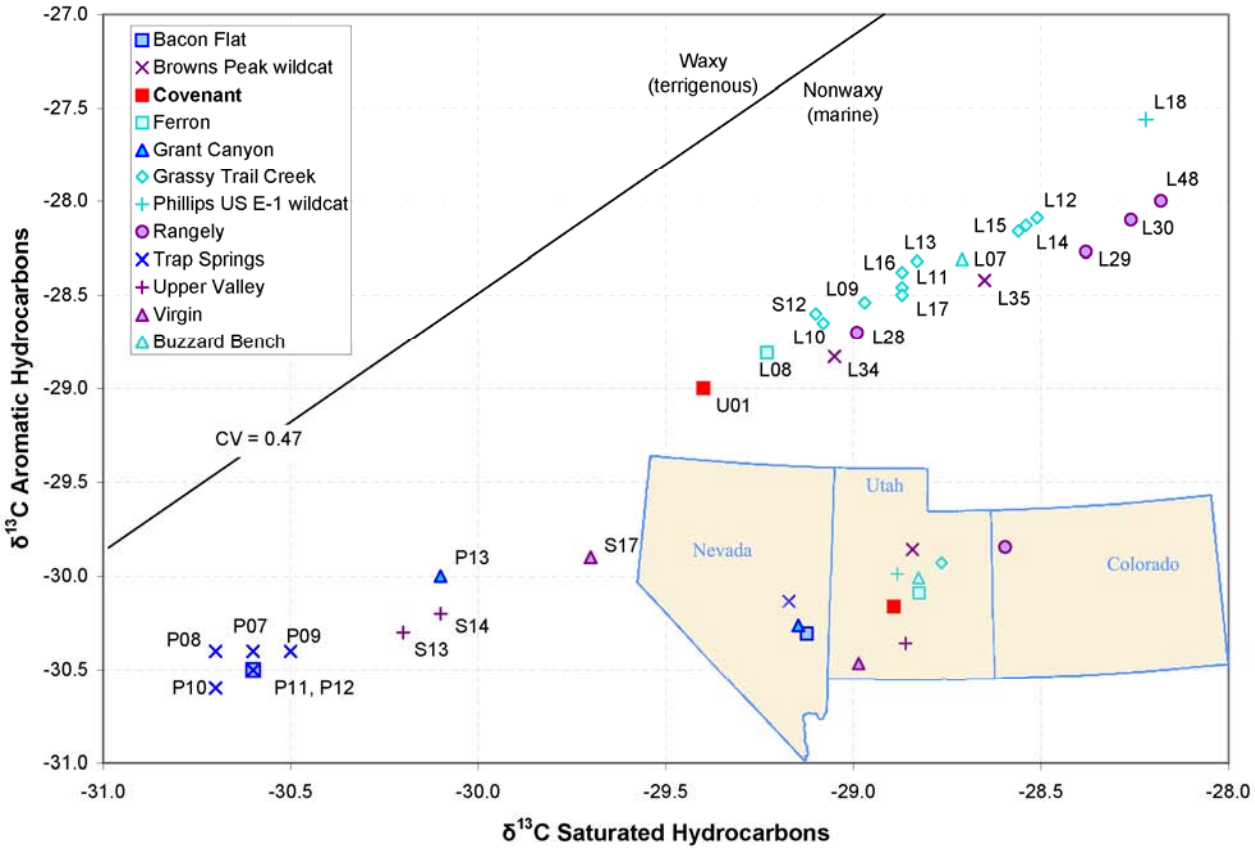


Figure 5-12. Stable carbon-13 isotope of saturated versus aromatic hydrocarbons from the Covenant field oil and other key oils from Utah, Colorado, and Nevada (see inset for field locations). Units on both axes of the graph depict the carbon isotopes measured in the oil versus the Pee Dee Belemnite (PDB) standard in parts per thousand; a negative value implies the oil sample is depleted in the heavy isotope relative to the standard. The line labeled CV = 0.47 (CV = canonical variable) divides waxy (terrigenous) and nonwaxy (marine) sources (Sofer, 1984), and shows that oils in this region are derived from marine sources.

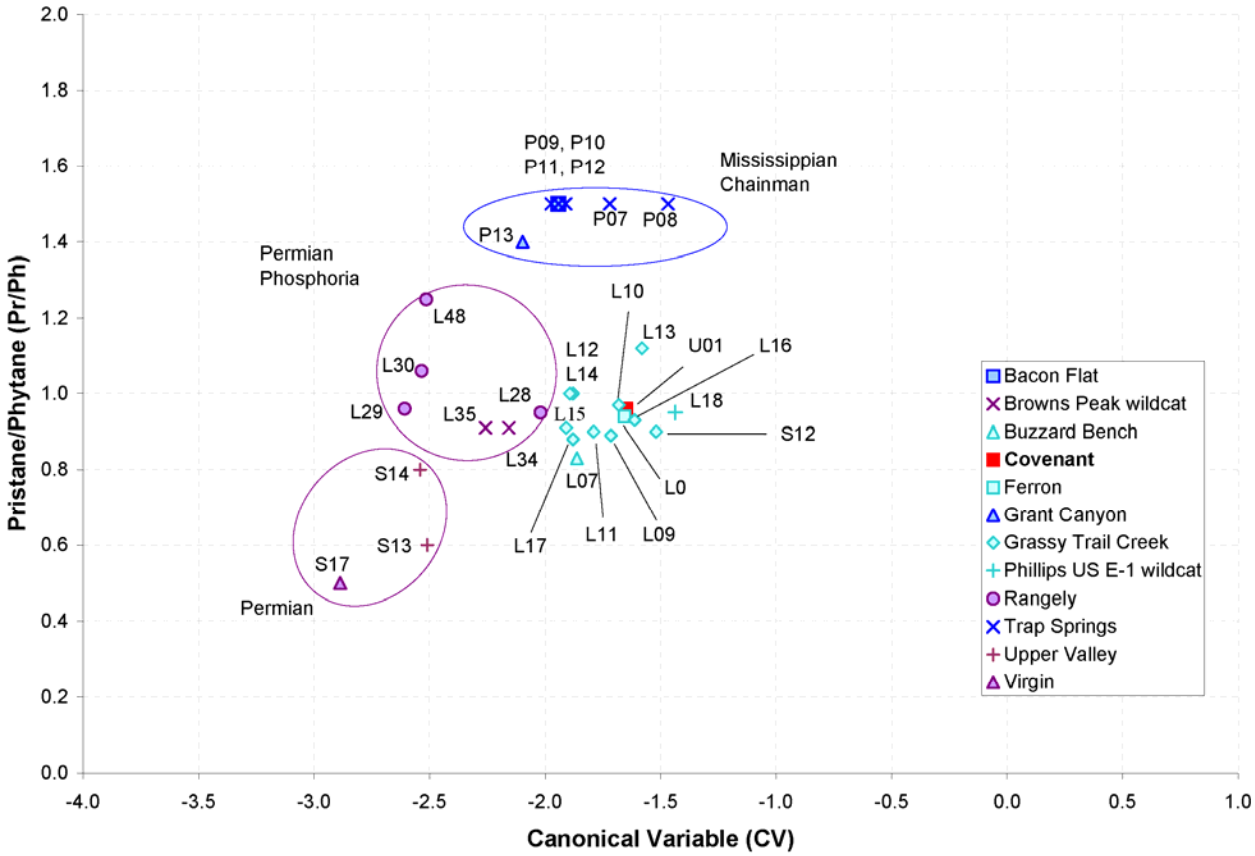


Figure 5-13. Canonical variable (CV) versus pristane/phytane values from the Covenant field oil and other key oils from Utah, Colorado, and Nevada (see figure 5-12 for field locations). The plot suggests the Covenant field oil is not likely derived from the Mississippian Chainman Shale, a major source of oil in Nevada, or the Permian Phosphoria Formation, a source of oil in Wyoming, northwestern Colorado, and northeastern Utah. This does not preclude the source of oil in the Covenant field from being a local Carboniferous organic-rich source bed. Correlation presented here is based on this plot only; other geochemical parameters should be used to fully evaluate the correlation of oils.

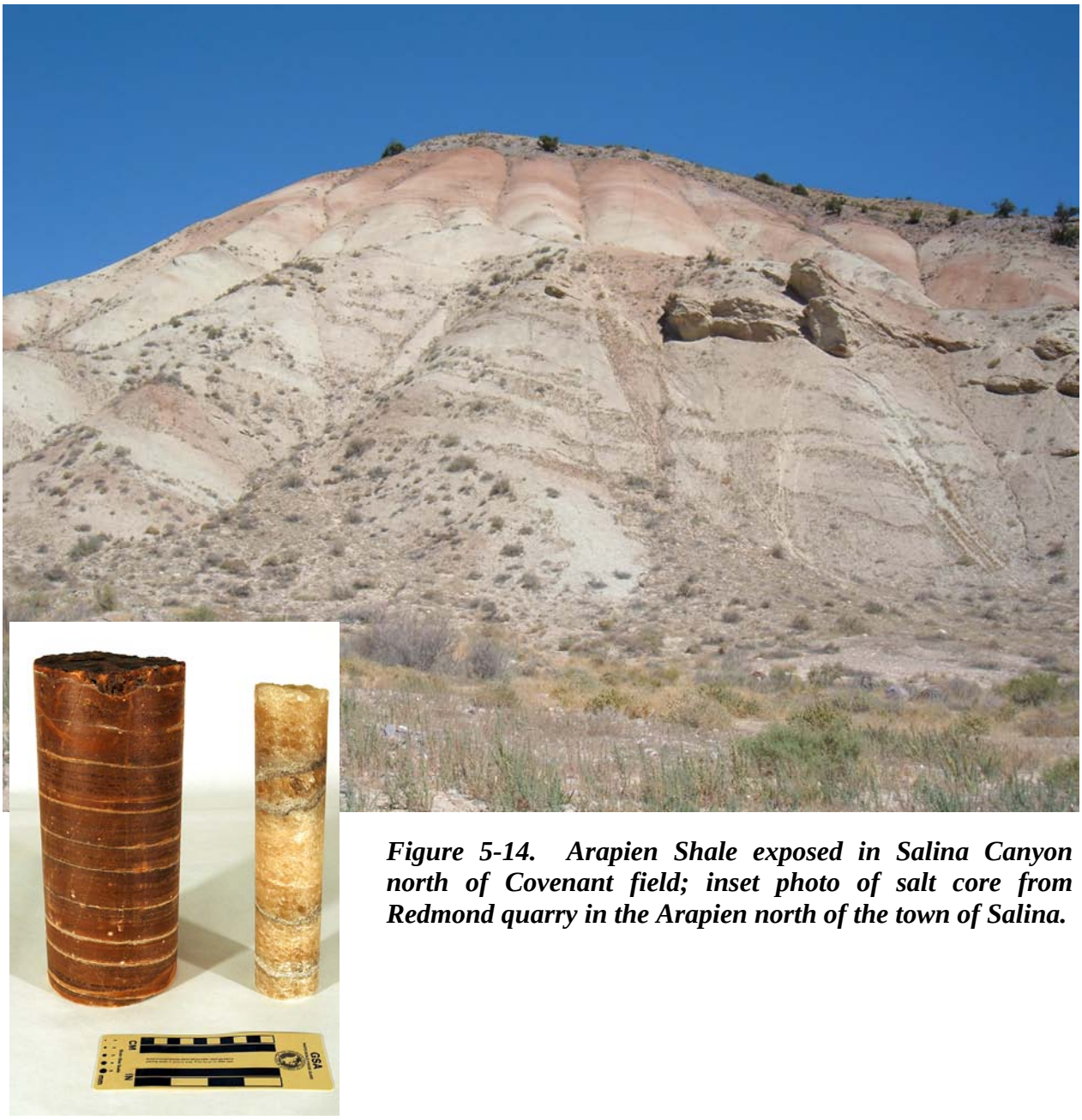


Figure 5-14. Arapien Shale exposed in Salina Canyon north of Covenant field; inset photo of salt core from Redmond quarry in the Arapien north of the town of Salina.

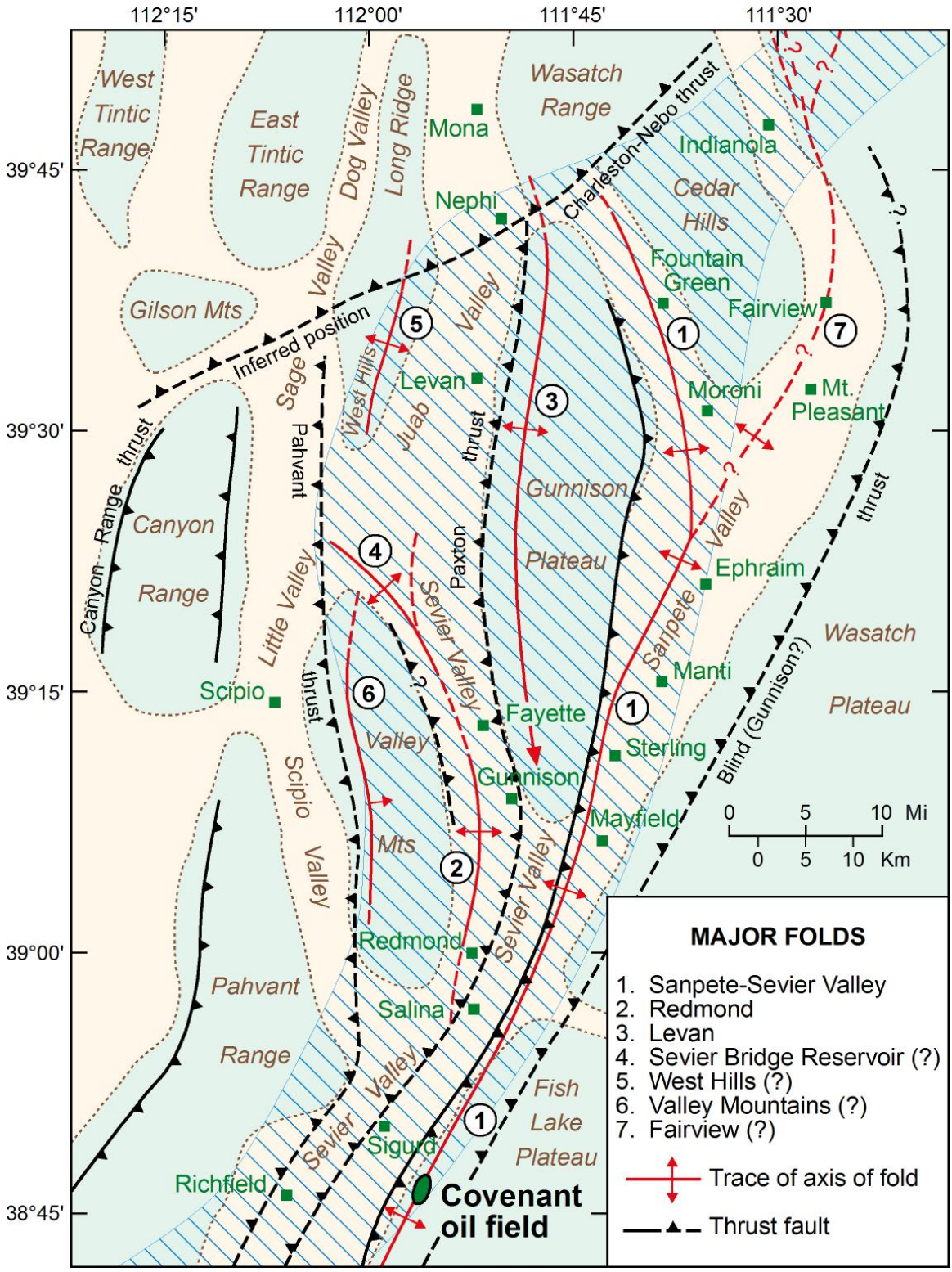


Figure 5-15. Major folds in central Utah (modified from Witkind, 1982). Play area represented by hachured pattern.

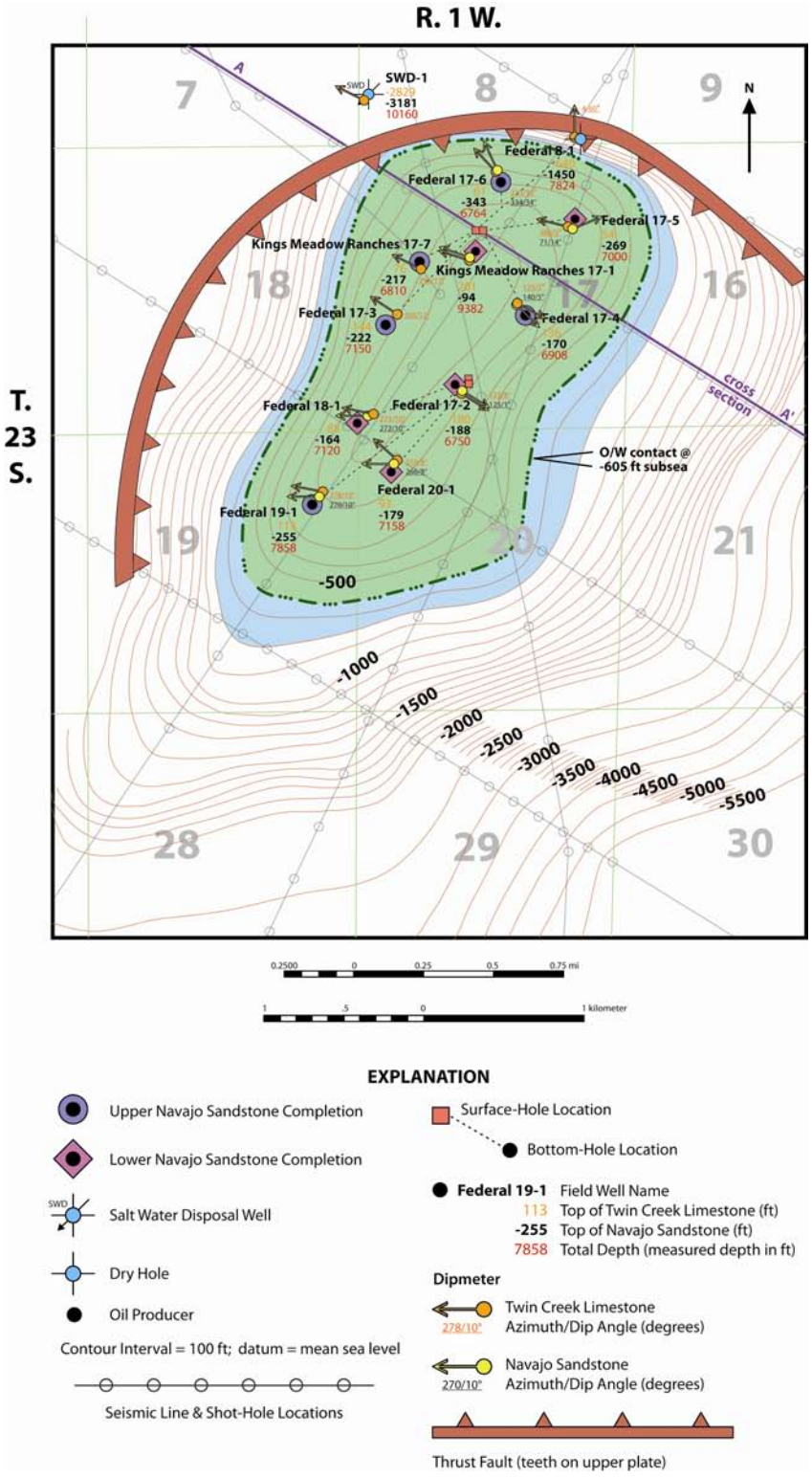


Figure 5-16. Structure contour map of the top of the Navajo Sandstone, Covenant field, based on subsurface well control and seismic data (Chidsey and others, 2007). Contour interval = 100 feet, datum = mean sea level. Line of cross section A-A', which extends beyond the edges of this figure, is shown on figures 5-1 and 5-17.

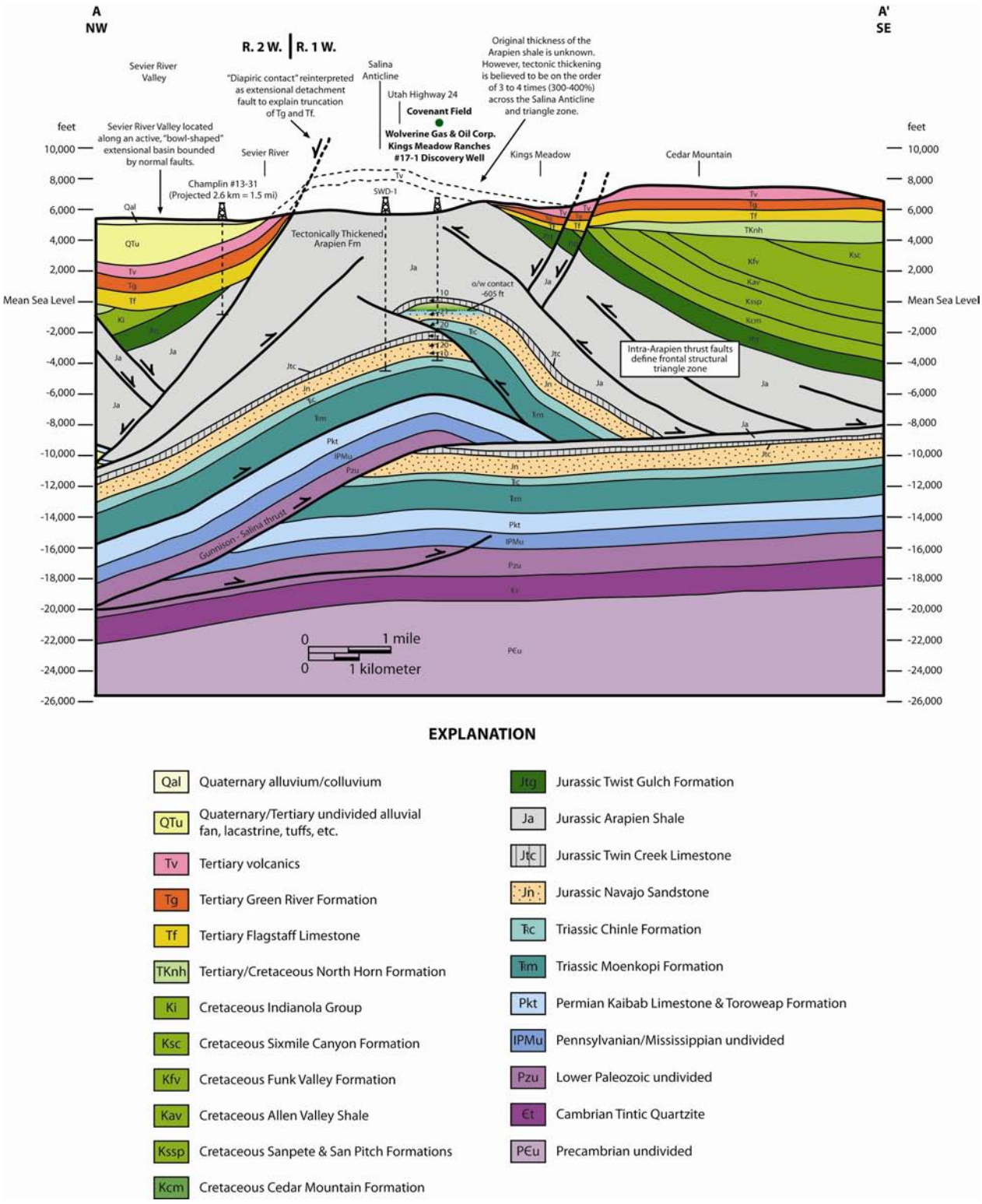


Figure 5-17. Northwest-southeast structural cross section through Covenant field (Chidsey and others, 2007). Note small back thrust through the anticline that results in a repeated Navajo Sandstone section. Line of cross section shown on figures 5-1 and 5-16.

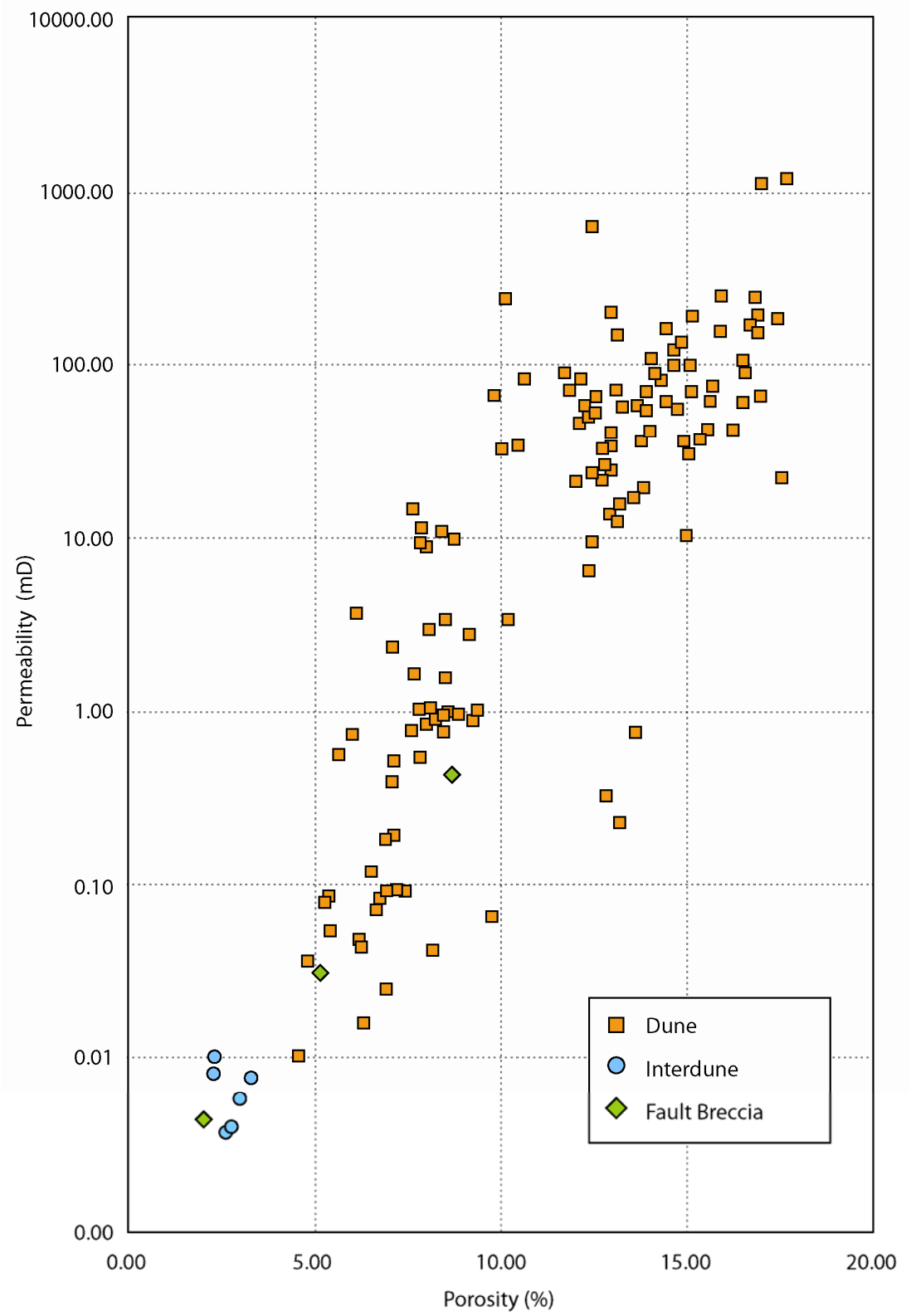


Figure 5-18. Porosity versus permeability cross plot from the Navajo Sandstone in Covenant field, based on core-plug analysis, showing gradational changes in reservoir quality within the various dune lithofacies and transitional changes to interdune lithofacies; zones of brecciation from faulting are also plotted.

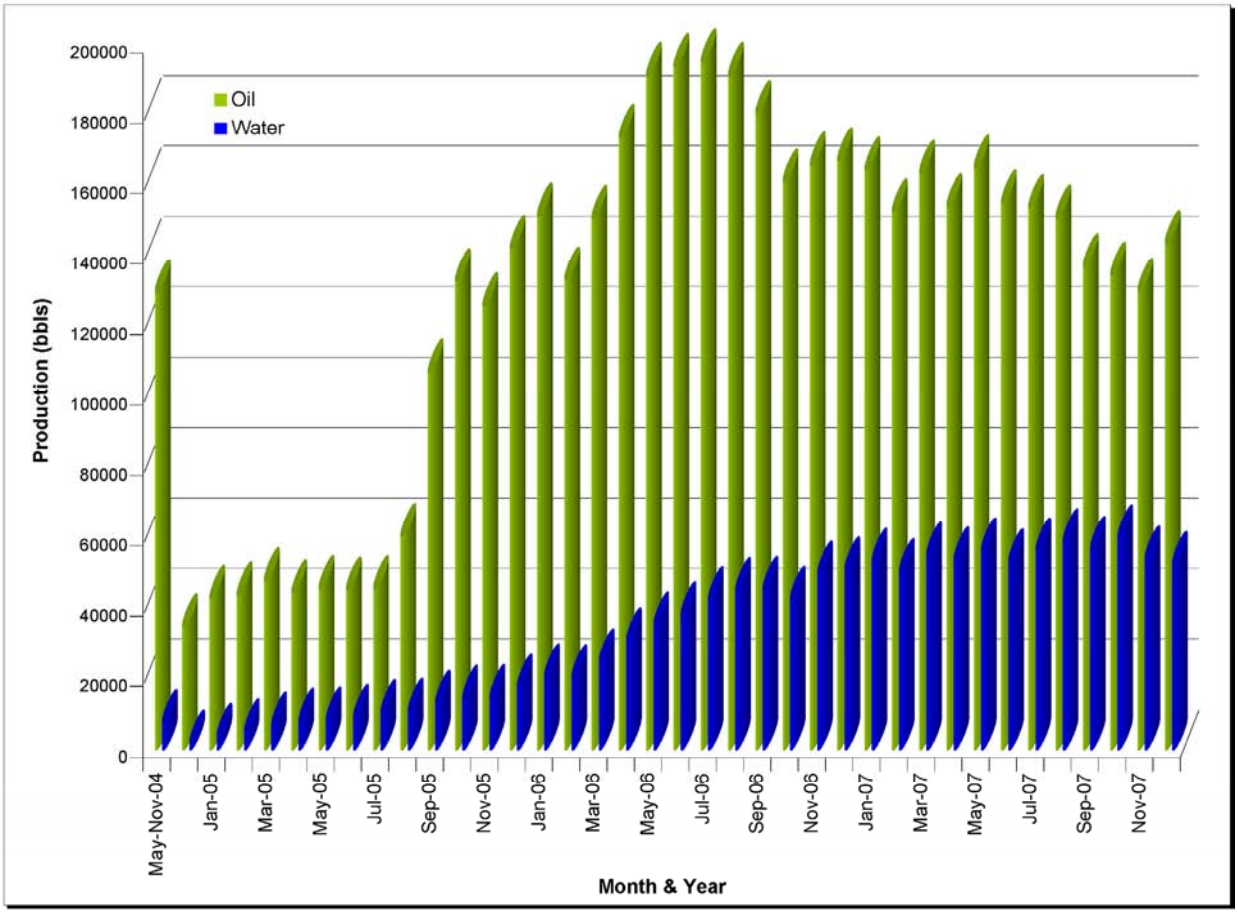


Figure 5-19. Monthly oil and water production from wells in Covenant field (Utah Division of Oil, Gas and Mining, 2007).

Table 5-1. Geochemistry of oils from Utah, Colorado, and Nevada (see figure 5-12 for field locations).

ID	Field	Reservoir	Reservoir Age	Oil Type	API[1]	Sulfur[2]	δ^{13}C Sat[3]	δ^{13}C Aro[4]	CV[5]	Pr/Ph[6]	CPI[7]	Well Name	County	State	Depth (ft)	Data Source
P12	Bacon Flat	Guilmette Formation	D	Mississippian Chainman	24.0	0.5	-30.60	-30.50	-1.94	1.50	1.50	Bacon Flat 1	Nye	Nevada	5316-5333	Poole and Claypool, 1984
L34	Browns Peak wildcat	Entrada Sandstone?	J	Permian Phosphoria	30.8	0.74	-29.05	-28.83	-2.16	0.91	1.00	Browns Peak Unit 1-G24	Utah	Utah	5788-5812	Lillis and others, 2003
L35	Browns Peak wildcat	Entrada Sandstone?	J	Permian Phosphoria	35.5	0.74	-28.65	-28.42	-2.26	0.91	0.97	Browns Peak Unit 1-G24	Utah	Utah	5788-5812	Lillis and others, 2003
L07	Buzzard Bench	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.71	-28.31	-1.86	0.83	0.99	Federal 41-33	Emery	Utah	9462-9472	Lillis and others, 2003
U01	Covenant	Navajo Sandstone	J	Carboniferous	40.5	0.48	-29.40	-29.00	-1.65	0.96	1.00	Kings Meadow Ranches 17-1	Sevier	Utah	6215-6225	Baseline DGSI, 2005
L08	Ferron	Kaibab Limestone	P	Uncertain Paleozoic	35.0	n.d.	-29.23	-28.81	-1.66	0.94	0.97	Pan Am 3 (Ferron Unit 42-21)	Emery	Utah	7154-7176	Lillis and others, 2003
P13	Grant Canyon	Guilmette Formation	D	Mississippian Chainman	27.0	0.5	-30.10	-30.00	-2.10	1.40	1.00	Grant Canyon 1	Nye	Nevada	4374-4426	Poole and Claypool, 1984
L09	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.97	-28.54	-1.71	0.89	0.98	Federal 11-23	Emery	Utah	3910-3940	Lillis and others, 2003
L10	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-29.08	-28.65	-1.68	0.97	1.01	Federal 11-33	Emery	Utah	3420-3906	Lillis and others, 2003
L11	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.87	-28.46	-1.79	0.90	0.98	Federal 1-14	Emery	Utah	3687-4010	Lillis and others, 2003
L12	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.51	-28.09	-1.88	1.00	1.00	Federal 11-41	Emery	Utah	3540-3911	Lillis and others, 2003
L13	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	36.5	0.33	-28.83	-28.32	-1.58	1.12	0.97	Federal 11-41	Emery	Utah	3540-3911	Lillis and others, 2003
L14	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.54	-28.13	-1.89	1.00	0.99	Federal 11-42	Emery	Utah	3453-3654	Lillis and others, 2003
L15	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.56	-28.16	-1.91	0.91	0.99	Federal 11-43	Emery	Utah	3382-3966	Lillis and others, 2003
L16	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.87	-28.38	-1.61	0.93	0.98	Federal 12-32	Emery	Utah	3627-3970	Lillis and others, 2003
L17	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.87	-28.50	-1.88	0.88	0.99	State 2-43X	Emery	Utah	3669-4162	Lillis and others, 2003
S12	Grassy Trail Creek	Moenkopi Formation	Tr	Uncertain Paleozoic	42.5	n.d.	-29.10	-28.60	-1.52	0.90	n.d.	Grassy Trail 1-33 Federal	Emery	Utah	3420-3906	Spinkel and others, 1997
L18	Phillips US E-1 wildcat	Sinbad Mbr. of Moenkopi Fm.	Tr	Uncertain Paleozoic	n.d.	n.d.	-28.22	-27.56	-1.44	0.95	0.98	United States E-1	Sanpete	Utah	16,115-16,425	Lillis and others, 2003
L28	Rangely	Weber Sandstone	IP	Permian Phosphoria	33.1	0.73	-28.99	-28.70	-2.02	0.95	1.02	Equity Federal 1-7	Rio Blanco	Colorado	6505-6535	Lillis and others, 2003
L29	Rangely	Weber Sandstone	IP	Permian Phosphoria	32.8	n.d.	-28.38	-28.27	-2.61	0.96	1.00	Equity Federal 1-7	Rio Blanco	Colorado	6505-6535	Lillis and others, 2003
L30	Rangely	Weber Sandstone	IP	Permian Phosphoria	34.5	n.d.	-28.26	-28.10	-2.53	1.06	1.00	Pennell-Hayes 1-31	Rio Blanco	Colorado	6175-6345	Lillis and others, 2003
L48	Rangely	Morrison Formation	J	Permian Phosphoria-Cretaceous Mancos mix	33.3	n.d.	-28.18	-28.00	-2.51	1.25	1.01	McLaughlin Stuart 2	Rio Blanco	Colorado	3225-3237	Lillis and others, 2003
P07	Trap Springs	Garrett Ranch Group	I	Mississippian Chainman	30.0	0.6	-30.60	-30.40	-1.72	1.50	1.00	Britton 13-21	Nye	Nevada	3976-4140	Poole and Claypool, 1984
P08	Trap Springs	Garrett Ranch Group	T	Mississippian Chainman	29.0	0.6	-30.70	-30.40	-1.47	1.50	1.00	Trap Springs 19	Nye	Nevada	3374-4100	Poole and Claypool, 1984
P09	Trap Springs	Garrett Ranch Group	T	Mississippian Chainman	21.0	0.6	-30.50	-30.40	-1.97	1.50	1.00	Zusspan 24-1	Nye	Nevada	4910-4944	Poole and Claypool, 1984
P10	Trap Springs	Garrett Ranch Group	T	Mississippian Chainman	19.0	0.6	-30.70	-30.60	-1.91	1.50	1.00	Trap Springs 1	Nye	Nevada	4220-4853	Poole and Claypool, 1984
P11	Trap Springs	Garrett Ranch Group	T	Mississippian Chainman	24.0	0.5	-30.60	-30.50	-1.94	1.50	1.00	Trap Springs 3	Nye	Nevada	3269-4083	Poole and Claypool, 1984
S13	Upper Valley	Kaibab Limestone	P	Permian	26.8	2.71	-30.20	-30.30	-2.51	0.60	n.d.	Upper Valley Unit 31	Garfield	Utah	6895-7020	Spinkel and others, 1997
S14	Upper Valley	Kaibab Limestone	P	Permian	19.9	2.94	-30.10	-30.20	-2.54	0.80	n.d.	Little Valley 1	Garfield	Utah	7606-7630	Spinkel and others, 1997
S17	Virgin	Kaibab Limestone	P	Permian	n.d.	n.d.	-29.70	-29.90	-2.89	0.50	n.d.	tank battery	Washington	Utah	surface	Spinkel and others, 1997

[1] oil gravity in degrees API

[2] weight percent sulfur

[3] δ^{13}C saturates in Pee Dee Belemnite (PDB) standard in parts per thousand

[4] δ^{13}C aromatics in Pee Dee Belemnite (PDB) standard in parts per thousand

[5] canonical variable (Sofer, 1984)

[6] pristane/phytane

[7] carbon preferential index (Hunt, 1979)

n.d. = no data

T - Tertiary
J - Jurassic
Tr - Triassic
P - Permian
IP - Pennsylvanian
D - Devonian

CHAPTER 6
DEEP UINTA BASIN OVERPRESSURED CONTINUOUS PLAY

Craig D. Morgan,
Utah Geological Survey

Introduction

The Deep Uinta Basin Overpressured Continuous play (DUBOCP) is located near the basin center where about the lower 2500 to 3000 feet (750-900 m) of the Green River and intertonguing Colton Formations are overpressured (gradient >0.5 pounds per square inch [psi/ft]; [11.3 kPa/m]) (figures 6-1 and 6-2). The most rapid increase in reservoir pressure and most of the high-volume, overpressured oil production is typically from depths of 11,000 to 14,000 feet (3400-4300 m) (figure 6-3). The drill depths given are averages; actual depth to the overpressured interval can vary greatly throughout the fields.

The play has produced nearly 300 million BO (50 million m^3) and 500 BCF (14 BCM) of associated gas from the three large fields – Altamont, Bluebell, and Cedar Rim (Utah Division of Oil, Gas and Mining, August 1, 2008). Production is fracture controlled from rocks with typically very low (< 0.1 millidarcies [mD]) matrix permeability. The reservoir is fractured lenticular sandstone, shale, and marlstone deposited in the lacustrine and alluvial environments of Lake Uinta (figure 2-12). Well completions typically consist of perforating 40 or more beds in a 1500-foot (450 m), or more, vertical section.

Depositional Environment

The Uinta Basin began developing in middle Paleocene time. Shallow lakes and wetlands (the depositional facies of the Flagstaff Member of the Green River Formation) existed in the deep basin area by early Paleocene time. Ancient Lake Flagstaff, followed by Lake Uinta (both lakes will be referred to as Lake Uinta), were dominant features throughout most of the late Paleocene and Eocene in the deep basin area. In most of the basin the Flagstaff is separated from the main portion of the Green River by alluvial deposits of the Colton Formation (figure 2-17). But in the central portion of the basin along the southern limits of Altamont and Bluebell fields, lacustrine deposits of Lake Flagstaff and Lake Uinta are continuous. Ryder and others (1976) defined three major depositional facies in the Colton and Green River Formations: (1) alluvial, (2) marginal lacustrine, and (3) open lacustrine. The depositional environments of the Colton and Green River are described in detail by Fouch (1975, 1976, 1981), Ryder and others (1976), Pitman and others (1982), Franczyk and others (1992), and Fouch and Pitman (1991, 1992).

Abundant detritus was shed from the south flank of the Uinta uplift into the deep basin area from late Paleocene into earliest Eocene time (Franczyk and others, 1992). Alluvial deposits of the Colton Formation were laid down along Lake Uinta's northern margin and intertongue with the deeper-basin, marginal-lacustrine deposits of the Green River Formation. The Colton thins rapidly from north to south in the deep basin play area. Expansion of Lake Uinta resulted in deposition of marginal-lacustrine and open-lacustrine sediments over the Colton (figure 6-4).

Stratigraphy and Thickness

The DUBOCP produces oil and associated gas, in ascending order, from the Flagstaff Member of the Green River Formation, the intertonguing Green River-Colton Formations, and the lower Green River Formation in the deepest portions of the play. The total thickness of the Green River, Colton, and Flagstaff Member strata can be more than 8000 feet (2400 m). The basal contact of the Flagstaff Member with the Paleocene part of the North Horn Formation is poorly defined and is rarely penetrated by wellbores. Typically the lower 2500 to 3000 feet (750-900 m) of the reservoir interval is overpressured and makes up the DUBOCP (figure 2-16). The total depth of most wells in the deep basin play is 12,000 to 14,000 feet (3600-4300 m).

Lithology and Fracturing

Hydrocarbons are produced in the DUBOCP from the Paleocene- and Eocene-age Colton and Green River Formations. Most of the production is from sandstone, but some production comes from shale, limestone, and marlstone beds with open fractures. Factors controlling most of the production in the deep basin play are predominantly the presence of fractures and the abnormally high fluid pressure, and to a lesser extent the facies and porosity distribution. Fractures in the DUBOCP reservoirs are believed to be the result of rapid generation of hydrocarbons within the largely impermeable rock (Lucas and Drexler, 1975; Narr and Currie, 1982; Bredehoeft and others, 1994).

A study of core from the Bluebell field by Wegner (1996) and Wegner and Morris (1996) showed that 78% of the sandstone beds and 43% of the clastic mudstone beds had at least one noticeable fracture. Fracture density, orientation, and fill vary with differing rock types; sandstone beds tend to have the lowest fracture density but the fractures are longer and generally have more separation than those found in other rock types (Wegner, 1996; Wegner and Morris, 1996). Naturally occurring fractures in the sandstone beds are commonly perpendicular to near-perpendicular to bedding, with a measured vertical length greater than 3.3 feet (1 m) (although many fractures extend out of the sample). Fracture widths range from 0.03 to 0.13 inches (0.5-3.0 mm), and the openings are only partially calcite filled (Wegner, 1996; Wegner and Morris, 1996; Morgan, 2003b). The core was not orientated and as a result, azimuths of the fractures could not be determined. The primary fractures in the DUBOCP play generally trend east-west whereas fractures in the shallower Green River reservoirs in the Altamont and Bluebell fields trend northwest-southeast. The fracture orientations are based on limited borehole imaging logs and borehole breakout analysis (Allison and Morgan, 1996) and seismic data (Harthill and Bates, 1996). More recent borehole imaging logs from the Cedar Rim and western Altamont fields indicate a more north-south fracture trend.

Hydrocarbon Source and Seals

The source rocks for the crude oil produced from the DUBOCP are kerogen-rich shale and marlstone of the black shale facies of the Flagstaff Member of the Green River Formation (Dubiel, 2003; Ruble, 1996) and the lower Green River Formation, which were deposited in nearshore and offshore open-lacustrine environments (Tissot and others, 1978; Ruble, 1996; Ruble and others, 1998). Anders and others (1992) showed that the 0.7% vitrinite reflectance level in the center of the Altamont and Bluebell fields is at a present depth of about 8400 feet

(2600 m). The 0.7% reflectance level indicates the maturity at which the onset of intense oil generation occurred. In most wells in Altamont and Bluebell fields, the 0.7% reflectance level is at or below the Mahogany oil shale, but above the middle marker of the Green River. As a result, only the lower Green River and the Flagstaff Member are in the oil-generation window.

Lacustrine source rocks in the deepest portion of the basin are presently at or near their maximum burial depth (Dubiel, 2003). Oil and gas are likely currently being generated below about 10,000 feet (3000 m) (Dubiel, 2003). Based on burial history and petroleum-generation modeling of the Shell Brotherson 1-11B4 well in the Altamont field, Dubiel determined that oil and gas generation began near the base of the Green River Formation around 40 Ma at a depth of 11,000 feet (3300 m). Peak generation occurred during maximum burial between 30 to 40 Ma. The zone of hydrocarbon generation has risen stratigraphically through time (Dubiel, 2003). Much of the oil in the DUBOCP was generated in-situ or has undergone only minor vertical and lateral migration. Dubiel (2003) states that in the deep basin oil has been undergoing thermal cracking to gas and condensate since about 35 Ma contributing to the overpressuring of the reservoir.

Vertical and horizontal seals for producing zones are unfractured shale and low-permeable marls within the Green River Formation.

Structure and Trapping Mechanisms

The DUBOCP is just south of the structural center of the Uinta Basin. Reservoir structure in the Altamont, Bluebell, and Cedar Rim fields is dominated by north dip into the basin (figure 2-10). Oil is trapped in natural pores and within fractures, which were opened by the high fluid pressures during oil generation (Bredehoeft and others, 1994; McPherson, 1996). Interbedded sandstone, shale, limestone, and marlstone deposited in alluvial to marginal-lacustrine environments pinch out updip into dominantly shale and marlstone deposited in an open-lacustrine environment. Updip facies changes, a reduction of fluid pressure, and associated closing of fractures in the structurally shallower strata combine to form the traps of the DUBOCP.

Reservoir Properties

Oil and gas production in the DUBOCP is from perforated intervals in the Flagstaff Member of the Green River Formation and in the transitional interval where the lower Colton Formation intertongues with the Flagstaff Member. In the Altamont-Bluebell-Cedar Rim field area (figure 6-1), the Colton and Flagstaff contain an oil-bearing overpressured section that is up to 3000 feet (900 m) thick. The upper Colton and lower Green River are productive and locally overpressured, but are included in the Conventional Northern Uinta Basin Play. Sandstone in the DUBOCP has well-log porosities from 1 to 14%, with an average of 5%, and core-derived matrix permeabilities of 0.01 mD or less (Morgan, 2003b). Open fractures are the primary reservoir property necessary for oil and gas production from the DUBOCP.

Oil and gas is produced from fractured sandstone, shale, limestone, and less commonly marlstone. Characterization of the DUBOCP reservoir is very poor due to the:

1. extremely limited amount of core relative to the areal extent and thickness of the reservoir,

2. extremely limited amount of borehole imaging logs from the reservoir,
3. extensive number of perforated beds in the well with little to no knowledge of the contribution each bed makes to the overall production, and
4. low density of wells.

The sandstone beds are typically lenticular channel deposits a few feet thick to rarely a few tens of feet thick, with very limited lateral extent. Thickness maps of many of the sandstone beds show no relationship to well productivity (Allison, 1995; Morgan, 1997). Shale and limestone beds deposited in the lacustrine environment are often more laterally extensive than the sandstone beds and can be useful correlation markers (Morgan, 2003b). The shale and limestone beds are typically a few feet thick to rarely a few tens of feet thick, but are generally less fractured (Morgan, 2003b).

The fractures, which are critical to oil and gas production in the DUBOCP, like the lithology, are poorly characterized. The fracturing is believed to be extensive and reduced reservoir pressure in some beds over a large area even with only one well per section is suspected in extensive fracture sets (Morgan, 2003b). Most infill wells have encountered high reservoir pressures from presumably more isolated fracture sets, which often have a more rapid decline than the extensive fracture set (Morgan, 2003b). The orientation, spacing, connectivity, and fluid-flow characteristics of the fractures are virtually unknown. Downspacing to four wells per section in the near future will provide additional information about the reservoir.

Well completions in the DUBOCP typically consist of perforating 40 or more beds in a 1500-foot (450 m), or more, vertical section and hydraulically fracturing them with hydrochloric acid or proppant fracture treatment. This is commonly referred to as a “shotgun” completion.

Reservoir pressure gradients in the DUBOCP vary from 0.5 to 0.8 psi/ft (11.3-18.1 kPa/m). Representative calculated reservoir pressures are 9600 psi (66,200 kPa) for Bluebell field (assuming 12,000-foot [3600 m] depth and a gradient of 0.8 psi/ft [18.1 kPa/m]), 8400 psi (58,000 kPa) for Altamont field (assuming 12,000-foot [3600 m] depth and a gradient of 0.7 psi/ft [15.8 kPa/m]), and 6000 psi (40,000 kPa) for Cedar Rim field (assuming 10,000-foot [3000 m] depth and a gradient of 0.6 psi/ft [13.5 kPa/m]). Bottom-hole temperature is typically greater than 210°F (99°C). The reservoir drive mechanisms include gas solution and pressure depletion. The wells yield a significant amount of water during the late stages of production but the water is not considered a major drive mechanism. Reservoir data for the individual fields in the DUBOCP are summarized in table 6-1.

Oil and Gas Characteristics

Most of the oil produced from the DUBOCP is characterized as yellow wax (table 6-2). The yellow wax from the John No. 2-7B2 well (section 7, T. 2 S., R. 2 W., Uinta Base Line and Meridian [UBL&M]) is a 39° API gravity crude with a paraffin content of 7.4%. Because of the high paraffin content, the yellow wax has a pour point of 95°F (35°C) and a cloud point of 132°F (56°C). The produced oil is stored on location in heated, insulated stock tanks to keep it above the pour-point temperature. Associated gas from the DUBOCP (table 6-3) contains an average of 73% methane, 14% ethane, 7.5% propane, 5.1% higher fractions, 0.3% CO_2, with an average heating value of 1380 Btu/ft^3 (Moore and Sigler, 1987). For additional information on geochemical analysis and biomarker studies of the Green River oils please refer to Ruble, 1996; Mueller, 1998; Mueller and Philp, 1998; Ruble and Philp, 1998; and Dubiel, 2003.

Production

Fields in the DUBOCP produce oil with large amounts associated gas. Altamont-Bluebell-Cedar Rim fields have produced 296 million barrels of oil (BO) (47 million m^3) and 508 billion cubic feet of gas (BCFG) (14.4 BCMG) as of January 1, 2008. The three fields combined produced 271,000 BO (43,100 m^3) and 548 MMCFG (15.5 MMCMG) from 511active wells during December 2007 (Utah Division of Oil, Gas and Mining, 2008). Many of the wells perforated in the deep overpressured interval also have perforations in the overlying Conventional Northern Uinta Basin play interval. As a result, the co-mingled production from the two plays cannot be accurately separated; therefore, all of the production from the Altamont-Bluebell-Cedar Rim fields is attributed to the DUBOCP. All of the production is from primary methods: no enhanced oil recovery techniques are being used in the Altamont-Bluebell-Cedar Rim fields. The OOIP and therefore the percent recovery are highly speculative due to poor understanding of the highly complex, thick (3000 feet [1000 m]), and laterally extensive (500 square miles [1295 km^2]) nature of the reservoir. With a well density of two wells per section, it is likely that the current production practice will recover less than 10% of the OOIP. Infill drilling, improved completion practices, and enhanced-oil-recovery techniques could all increase the ultimate oil recovery.

Exploration Potential and Trends

The DUBOCP is well defined by drilling in the Altamont-Bluebell-Cedar Rim field area (figure 6-1). It is highly unlikely that any new large field discoveries will be made in the Uinta Basin that produce from the overpressured portion of the Colton and Green River Formations. Drilling may result in some field extensions but even that will be limited by the well-defined overpressured region within the basin.

Infill drilling will continue in portions of the Altamont-Bluebell-Cedar Rim field area where the deep overpressured play has not been developed on two wells per section. Drilling three wells per section has been allowed on a few select sections with the fields. Testimony to allow four wells per section in the Altamont-Bluebell-Cedar Rim fields was presented to the Utah Board of Oil, Gas and Mining and approved in December 2008. Enhanced oil recovery (EOR) methods have not been attempted in the Altamont-Bluebell-Cedar Rim field area. Several factors have discouraged operators from attempting any EOR pilot projects. Fractures are the dominant reservoir property and could cause early breakthrough of any injected fluid or gas. Fractures can result in injected fluids or gases moving great distances, perhaps even beyond the intended EOR unit. Enhanced-oil-recovery methods generally require a high density of wells to be effective. The Altamont-Bluebell-Cedar Rim field area has been developed with two wells per section and in many areas at least one of those wells has already been plugged and abandoned. As a result, any EOR method would require a significant amount of additional deep drilling. Allowing the production of four wells per section will be a significant step in improving the understanding of the reservoir and potential development of EOR.

The gross productive interval is 1000 to 3000 feet (300-1000 m) thick, with no single bed being a dominant producer, as a result, horizontal drilling has not been attempted in the Altamont-Bluebell-Cedar Rim fields. High angle well bores have been drilled in an attempt to encounter thicker productive beds and intersect more fractures. The high angle wells were

expensive to drill, more difficult to complete and produce, and did not result in any significant improvement in production.

Seismic data has had limited use in the Altamont-Bluebell-Cedar Rim fields. In the 1990s Pennzoil used seismic to map the thickness of the Green River Formation and drilled what they hoped was the deepest portions of Lake Uinta with the largest volume of source rock. Drilling based on the seismic did not result in better producing wells. Amplitude variation with offset (AVO) seismic analysis and vertical seismic profile (VSP) analysis was used to map fractures in the upper Green River in a portion of the Altamont field (T. 1 S., R. 2 W.) where shallow gas was being produced (Harthill and Bates, 1996; Harthill and others, 1997; Lynn and others, 1995; Lynn and others, 1999). The process has not been used to identify specific drilling locations in the upper Green River and is probably not practical for the deeper Green River due to the large offsets that would be necessary. Three-dimensional (3D) seismic has been successfully used in many hydrocarbon plays. Since fractures, not structure or stratigraphy, is a dominant control on reservoir performance, 3D seismic has not been used in the Altamont-Bluebell-Cedar Rim fields.

A large resource potential in the DUBOCP may be in recompletions of the current wells. The wells in the Altamont-Bluebell-Cedar Rim field area were completed in a shotgun fashion with perforations in 40 or more beds in a 1500-foot (450 m) or greater vertical interval. Consequently, many of the beds may never have received adequate stimulation. Using cased-hole logs to identify by-passed oil, and selectively stimulating individual beds can recover a significant amount of additional oil. The potential to recomplete wells in the Bluebell field was the subject of a DOE-funded study lead by the UGS (Morgan, 2003). The Malnar Pike well in the field was recompleted as part of the UGS demonstration and is an example of increased oil production from just two beds (figure 6-5). A new operator took control of the Roosevelt unit in the Bluebell field and began a program of recompletions that has resulted in oil production increasing from 561 BO/month (89 m^3/month) to more than 13,000 BO/month (2100 m^3/month).

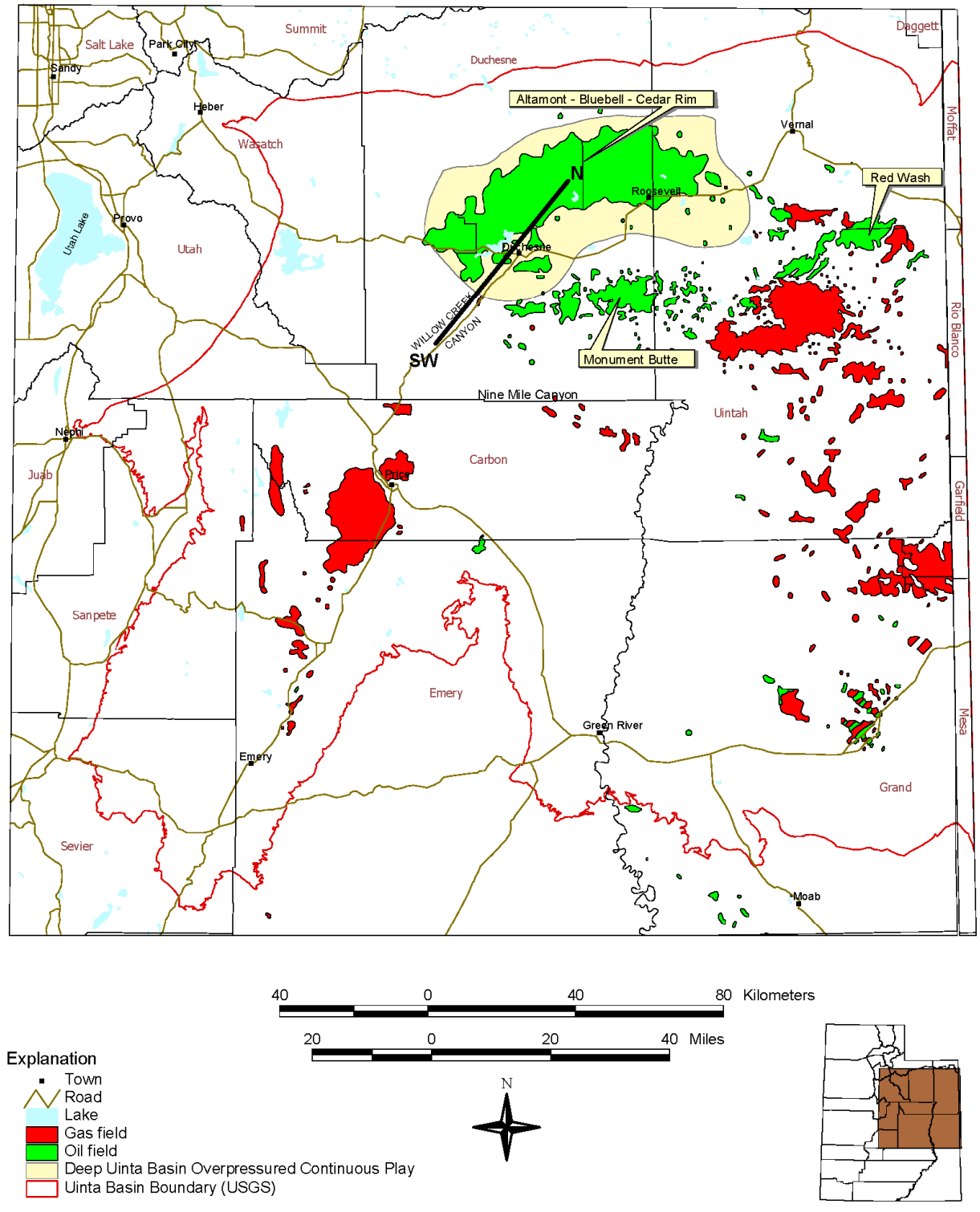


Figure 6-1. Location of the Deep Uinta Basin Overpressured Continuous play in northern Uinta Basin. The play encompasses the Altamont, Bluebell, and Cedar Rim fields. North-southwest cross section shown on figure 6-2.

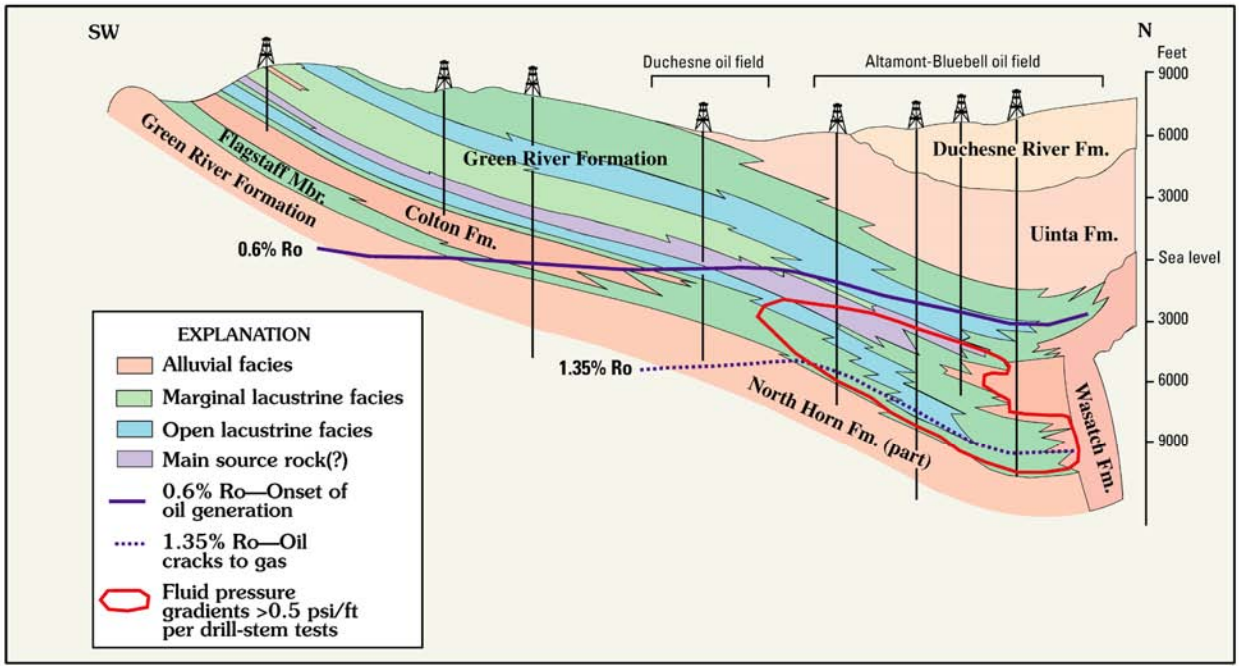


Figure 6-2. Generalized stratigraphic cross section of the Green River total petroleum system showing the overpressured interval of the Deep Uinta Basin Overpressured Continuous play. Line of section shown on figure 6-1. From Dubiel (2003).

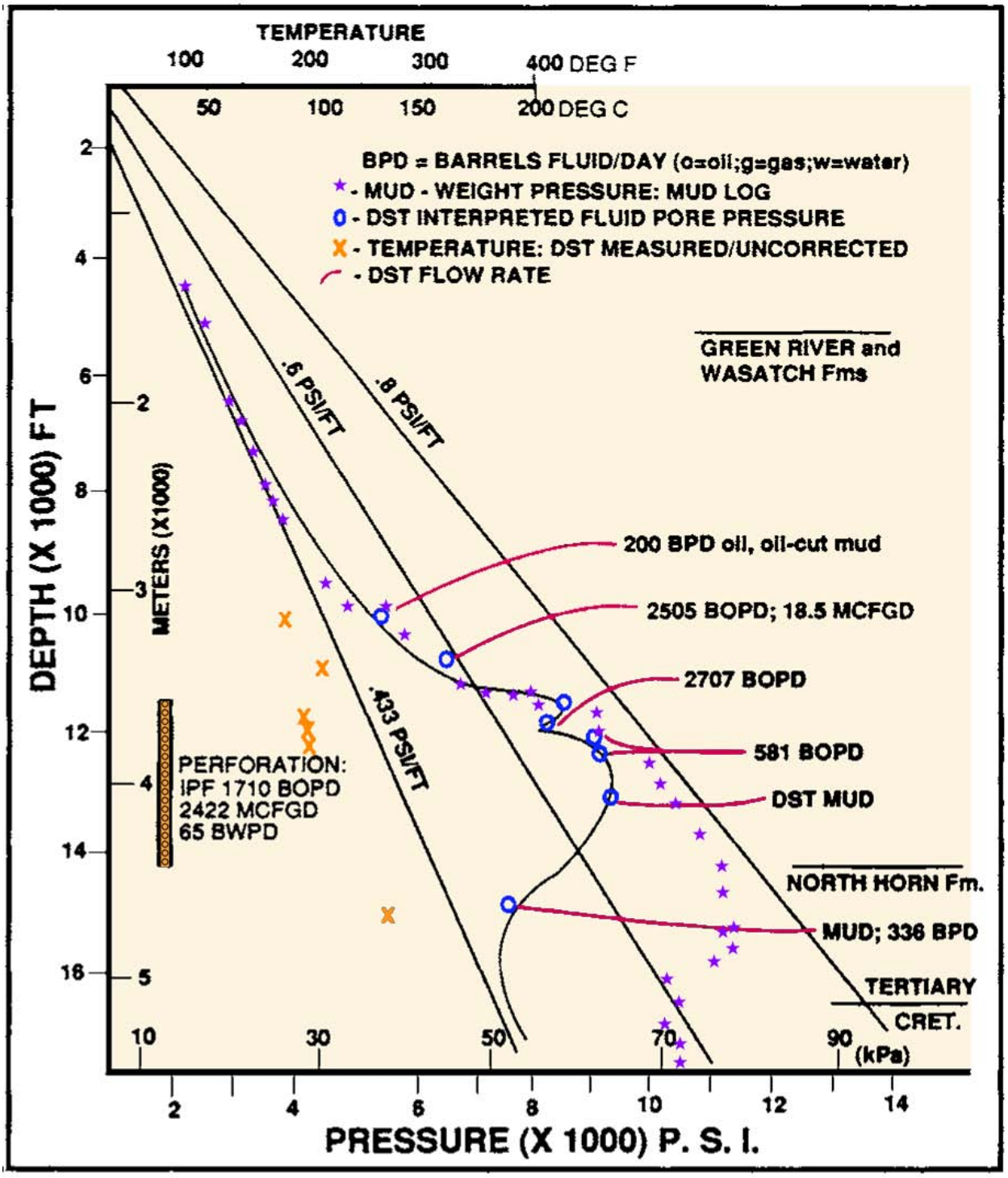


Figure 6-3. Plot of pressure versus depth for the Brotherson No. 1-11B4 well (section 11, T. 2 S., R. 4 W., UBL&M) at Altamont field. From Bredehoeft and others (1994).

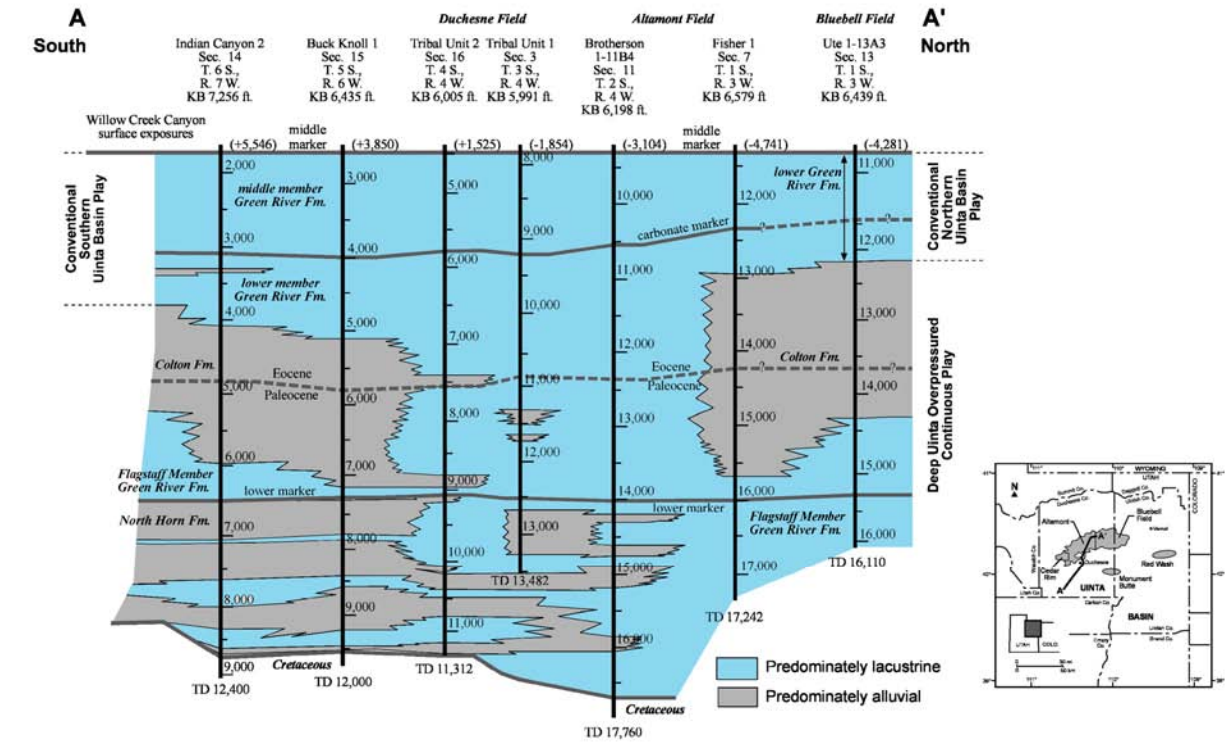


Figure 6-4. Generalized stratigraphic cross section which extends from outcrops in Willow Creek Canyon through Duchesne, Altamont, and Bluebell fields. Correlations of markers and depositional interpretations for many of the wells are from Fouch (1981). Datum is the middle marker with sea-level elevations in parentheses.

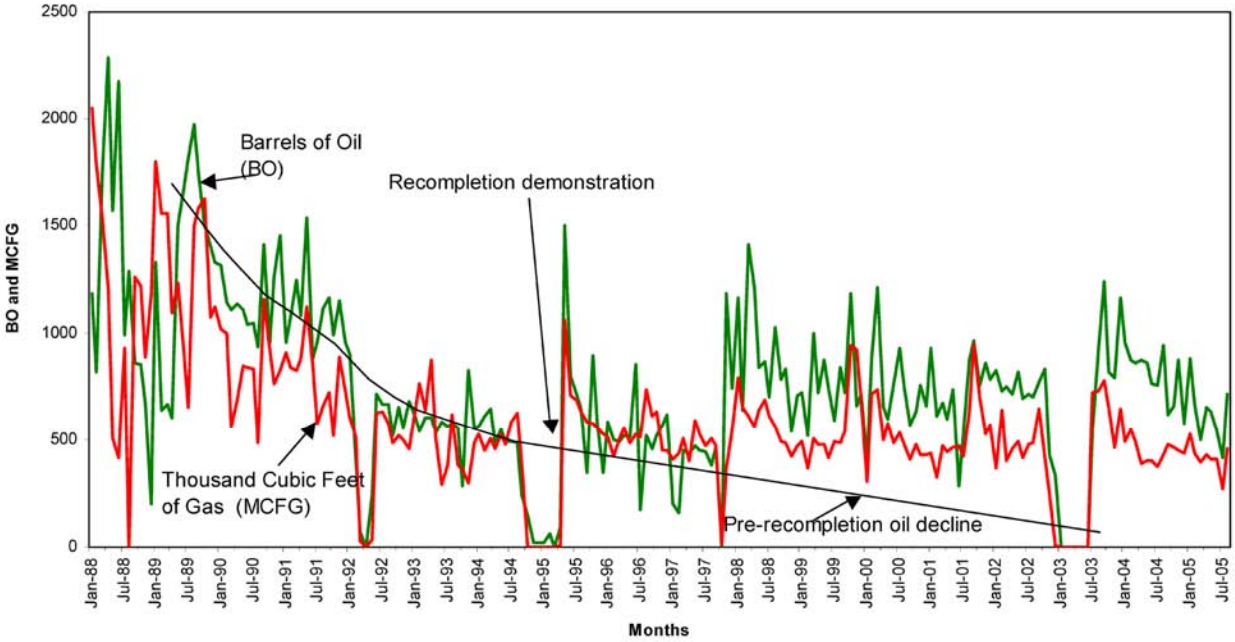


Figure 6-5. Monthly oil and gas production from the Malnar Pike well (section 17, T. 1 S., R. 1 E., UBL&M), Bluebell field, showing the increased oil production after recompleting in just two beds as part of the U.S. Department of Energy-funded Utah Geological Survey demonstration project (Morgan, 2003b). This is an example of potential that still exists in a well that has produced for many years in the Deep Uinta Basin Overpressured Continuous play. Data from Utah Division of Oil, Gas and Mining.

Table 6-1. Geologic, reservoir, and production data for the largest fields in the Deep Uinta Basin Overpressured Continuous play. Production data is from Utah Division of Oil, Gas and Mining, (2008); other data from Robertson and Broadhead (1993), Smouse (1993a), and Morgan (2003b).

State	County	Field	Discovery Date	Active Producers	Abandoned Producers	Acres	Spacing (acres)	Pay (feet)	Porosity (%)	Perm. (mD)	Temp. (^{O}F)	Initial Reservoir Pressure (psi)*	Monthly Production		Cumulative Production	
													Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
Utah	Duchesne	Altamont	1970	250	165**	139,720	320	40+	5-12	0.1	217	8400	76,778	203,106	118,542,858	245,151,302
Utah	Duchesne/ Uintah	Bluebell	1971	297	**	129,040	320	40+	5-12	0.1	218	9600	181,778	291,718	156,904,340	216,687,418
Utah	Duchesne	Cedar Rim	1969	27	22	21,820	320	40+	5-12	0.1	212	6000	12,282	80,834	13,001,634	28,865,861

* Pressure data estimated based on 12,000 feet and a gradient of 0.8 psi/ft for Bluebell, 12,000 feet and 0.7 psi/ft for Altamont, and 10,000 feet and 0.6 psi/ft for Cedar Rim fields.
** Abandoned producers for the Altamont and Bluebell fields are combined.

Table 6-2. Comparison of Uinta Basin crude oils. Yellow-wax sample from John No. 2-7B2 well (section 7, T. 2 S., R. 2 W., UBL&M), black-wax sample from Leslie Taylor No. 24-5 well (section 24, T. 1 S., R. 1 W., UBL&M). The Monument Butte black wax is an average from three wells: Monument Butte Nos. 10-35, 8-35, and 12-35 (section 35, T. 8 S., R. 16 E., SLBL&M). From Morgan (2003b).

Oil Characteristics	Bluebell Yellow Wax (DUBOCP*)	Bluebell Black Wax (CNUBP*)	Monument Butte Black Wax (CSUBP*)
Paraffin Content	7.4% wt.	12.2% wt.	9.6% wt.
Cloud Point	132°F	157°F	122°F
Pour Point	95°F	120°F	95°F
API Gravity	39°	33°	34°

* DUBOCP = Deep Uinta Basin Overpressured Continuous play, CNUBP = Conventional Northern Uinta Basin play, CSUBP = Conventional Southern Uinta Basin play.

Table 6-3. Comparison of associated gas from Uinta Basin oil plays. From Moore and Sigler (1987).

Play*	Field	Well	Methane	Ethane	Propane	Higher Fractions	Carbon Dioxide	Hydrogen Sulfide	Btu/ft^3
CNUBP	Red Wash	Unit 1	92.0	2.1	2.1	2.7	1.3	0.0	1096
CNUBP	Red Wash	Unit 32-27C	97.6	0.9	0.2	0.4	0.1	0.0	1026
CNUBP	Bluebell	Unit 2	96.0	1.1	0.9	1.1	0.1	0.0	1057
DUBOCP	Bluebell	Hamblin 1	73.7	14.4	7.2	4.2	0.4	0.0	1347
DUBOCP	Altamont	Brotherson 1	71.4	14.3	7.8	6.0	0.2	0.0	1409
CSUBP	Monument Butte	Unit 10-35	71.8	14.9	9.9	3.3	NA	NA	NA

* CNUBP = Conventional Northern Uinta Basin play, DUBOCP = Deep Uinta Basin Overpressured Continuous play, CSUBP = Conventional Southern Uinta Basin play.

CHAPTER 7
CONVENTIONAL NORTHERN UINTA BASIN PLAY

Craig D. Morgan,
Utah Geological Survey

Introduction

The Conventional Northern Uinta Basin play (CNUBP) covers the northern Uinta Basin and typically has drill depths ranging from 5000 feet (1500 m) to a maximum of 10,000 feet (3000 m). The play is divided into two subplays (figure 7-1): (1) Conventional Bluebell subplay, and (2) Conventional Red Wash subplay.

Depositional Environment

The CNUBP produces from the Eocene Colton and Green River Formations. Reservoir rocks in the Conventional Bluebell subplay consist of sandstone, shale, limestone, and marlstone deposited in intertonguing alluvial, marginal-lacustrine, to open-lacustrine environments (figures 2-12 and 2-17). Reservoir rocks in the Conventional Red Wash subplay are dominantly sandstone deposited in a shoreface lacustrine environment.

Conventional Bluebell Subplay

The Conventional Bluebell subplay consists of the Altamont-Bluebell-Cedar Rim field area and land north and west of the fields. The Conventional Bluebell subplay overlies the DUBOCP. The Conventional Bluebell subplay produces from the lower Green River Formation and the Green River to Colton transitional facies at drill depths of 8000 to 10,000 feet (2400-3000 m). Most of the production is from sandstone shed from the Laramide-age Uinta uplift to the north and deposited in alluvial and marginal-lacustrine environments.

Conventional Red Wash Subplay

The Conventional Red Wash subplay consists of several fields in the northeast portion of the Uinta Basin; the largest is the Red Wash field. The Conventional Red Wash subplay produces from the Douglas Creek Member in the lower portion of the Green River Formation at drill depths of 5000 to 6000 feet (1500-1800 m). Production is from sandstone deposited in shoreface to shoreline environments. The Red Wash subplay has the highest average matrix permeability (50-500 mD) of any of the plays in the Green River–Colton Formations.

Borer and McPherson (1998) provide the following description of the depositional environment of the Green River Formation at Red Wash field.

> In Red Wash, the overwhelming depositional overprint is that of wave/storm domination. It represents a high sediment supply and high accommodation regime. Middle and upper shoreface regimes are by far the most dominant reservoir facies. Sediment gravity flows, suspension fall out deposits and fluvial deposits are also of reservoir quality and can have

a large impact locally on production and waterflood behavior. We consider many sediment gravity flows to be the result of high-energy storm impacts on the shoreline.

Stratigraphic Thickness

The Green River and Colton Formations have a combined thickness of more than 6000 feet (1800 m) in the northern Uinta Basin but only a portion of the stratigraphic interval is included in the CNUBP. The Bluebell subplay has a 2000-foot-thick (600 m) productive interval in the lower Green River and upper transitional Colton Formations. The Red Wash subplay has a 1000-foot-thick (300 m) productive interval (figure 2-16) in the Douglas Creek Member.

Lithology and Fracturing

The dominant oil-productive lithology is sandstone; some production is from fractured shale, limestone, and marlstone in the Conventional Bluebell subplay. Fractures are encountered in both plays and generally enhance the reservoir quality, but are more common in the Bluebell subplay than in the Red Wash subplay.

Fractures are an important part of the Conventional Bluebell subplay reservoir and the underlying DUBOCP in the Altamont, Bluebell, and Cedar Rim fields. The fractures in the Conventional Bluebell subplay generally have a different orientation and possibly a different origin than the fractures in the underlying DUBOCP. Based on limited data, fractures in the DUBOCP reservoirs generally trend east-west, whereas fractures in the overlying Conventional Bluebell subplay reservoirs trend northwest-southeast (Allison and Morgan, 1996; Harthill and Bates, 1996; Morgan, 2003b). In the western Altamont and Cedar Rim fields a north-south fracture set, possibly related to Basin and Range extension, has been identified. Fractures in the DUBOCP reservoirs are believed to be the result of rapid generation of hydrocarbons within the largely impermeable rock (Lucas and Drexler, 1975; Narr and Currie, 1982; Bredehoeft and others, 1994). The Conventional Bluebell subplay reservoirs are not overpressured (0.5 pounds per square inch per foot [psi/ft]; 11.3 kPa/m) to slightly overpressured, but have open fractures that are probably related to tectonic movement of the basin rather than hydrofracturing during oil generation. As a result, the fractures in the Conventional Bluebell subplay are not controlled by the distribution and thermal maturity of oil-source rock. Fractures in the Conventional Bluebell subplay are typically vertical to near vertical and often have significant calcite filling (Morgan, 2003a).

Hydrocarbon Source and Seals

The source rocks for the crude oil produced from the CNUBP are kerogen-rich shale and marlstone of the black shale facies of the Green River Formation, which were deposited in nearshore and offshore open-lacustrine environments (Hunt and others, 1954; Forsman and Hunt, 1958; Silverman and Epstein, 1958; Tissot and others, 1978; Ruble, 1996; Ruble and others, 1998). Anders and others (1992) showed that the 0.7% vitrinite reflectance level in the center of the Altamont and Bluebell fields is at about 8400 feet (2600 m) drill depth. The 0.6% reflectance level is the depth at which the onset of intense oil generation occurred. In most wells in Altamont and Bluebell, the 0.6% maturity level is at or below the Mahogany oil shale, but

above the middle marker of the Green River. As a result, only the lower Green River and the Flagstaff Member are in the oil-generation window.

Lacustrine source rocks in the deepest portion of the basin are presently at or near their maximum burial depth (Dubiel, 2003). Oil and gas are likely currently being generated below about 10,000 feet (3000 m) (Dubiel, 2003). Based on burial history and petroleum-generation modeling of the Shell Brotherson 1-11B4 well in the Altamont field, Dubiel determined that oil and gas generation began near the base of the Green River Formation around 40 Ma at a depth of 11,000 feet (3300 m). Peak generation occurred during maximum burial between 30 to 40 Ma. The zone of hydrocarbon generation has risen stratigraphically through time (Dubiel, 2003). Much of the oil in the CNUBP was generated in-situ from the black shale facies in the lower Green River and has undergone only minor vertical and lateral migration in the Conventional Bluebell Subplay. Rocks in the Red Wash and neighboring fields have mean random vitrinite reflectance (Rm) values in the range of 0.40 to 0.55%. The oils from the Red Wash and neighboring fields have thermal maturity geochemical indices equivalent to 0.7 to 0.8% Rm, indicating migration from more deeply buried, higher temperature source rocks in the Bluebell-Altamont area. Vertical and horizontal seals for producing zones are unfractured shale and low-permeable marls within the Green River.

Structure and Trapping Mechanisms

Stratigraphic traps are the primary trapping mechanism for reservoirs in the CNUBP. Structure is dominantly regional dip northward into the basin with minor flexures or subtle plunging structural anticlinal trends with no four-way closure.

The trap in the Conventional Bluebell subplay is formed by the updip (north to south) pinchout of alluvial and marginal lacustrine sandstone beds into offshore marlstone and shale beds. A subtle west-plunging anticline is mapped at Bluebell field in the lower Green River Formation (figure 7-2), which is not present at deeper horizons. The Altamont and Cedar Rim fields also have a regional northerly dip (figure 2-10).

The trap in the Conventional Red Wash subplay is formed by updip (northwest to southeast) pinchout of wave-dominated marginal lacustrine sandstone beds. A subtle west- to northwest-plunging anticline is mapped in the Red Wash field (figure 7-3).

Reservoir Properties

Oil and gas production in the CNUBP is from the lower Green River Formation and upper Colton Formation (upper Green River/Colton transition). In the Conventional Bluebell subplay the sandstone reservoirs typically have low porosity (8 to 12%) and low matrix permeability (0.01 to 10 millidarcies [mD]). The sediment was shed from the Uinta uplift directly north of the play area, deposited as sandstone in alluvial channels and fans, shallow marginal-lacustrine channels and bars in a low-energy environment with very little reworking of the sediment. As a result, the sandstone reservoirs typically are high in clay content and well cemented. Oil and gas is produced from fractured sandstone, shale, limestone, and less commonly marlstone. Characterization of the Conventional Bluebell subplay reservoir is very poor due to the:

1. extremely limited amount of core relative to the areal extent and thickness of the reservoir,
2. extremely limited amount of borehole imaging logs from the reservoir,
3. extensive number of perforated beds in the well with little to no knowledge of the contribution each bed makes to the overall production, and
4. low density of wells.

The sandstone beds are typically lenticular channel and shoreface storm deposits a few feet thick to rarely a few tens of feet thick, with very limited lateral extent. Thickness maps of many of the sandstone beds show no relationship to well productivity (Allison, 1995; Morgan, 1997). Shale and limestone beds deposited in the lacustrine environment, are often more laterally extensive than the sandstone beds and can be useful correlation markers (Morgan, 2003b). The shale and limestone beds are typically a few feet thick to rarely a few tens of feet thick, but are generally less fractured (Morgan 2003b).

Fractures in the Conventional Bluebell subplay, like the lithology, are poorly characterized. The orientation, spacing, connectivity, and fluid flow characteristics of the fractures are virtually unknown. Downspacing to four wells per section in the near future will provide additional information about the reservoir.

In contrast, the sandstone in the Red Wash field area was derived from wave and storm dominated deposits in a shoreface environment on a steeper, higher energy shelf, and underwent greater reworking during deposition. As a result, the sandstone reservoirs in the Conventional Red Wash subplay have higher porosities (8 to 20%) and significantly higher matrix permeabilities, commonly 50 to 500 mD. Sandstone beds generally range from a few feet to tens of feet thick. Most fields in the Conventional Red Wash subplay produce from multiple beds. The sandstone beds in the Conventional Red Wash subplay are generally more laterally extensive than many of the beds in the Conventional Bluebell subplay. Reservoir data for individual fields in the Conventional Red Wash subplay are summarized in table 7-1.

Oil and Gas Characteristics

Most of the oil produced from the CNUBP is characterized as black wax (table 6-2). The black wax typically has a gravity of 28 to 32°API gravity. The crude at Red Wash field has a lower pour point, 80 to 95°F (27-35°C), than the black wax at Bluebell field, which has a pour point of about 120°F (49°C).

Associated gas from the Red Wash field (table 6-3) contains an average of 95% methane, 1.5% ethane, 1.1% propane, 1.6% higher fractions, 0.7% carbon dioxide (CO_2), with an average heating value of 1060 Btu/ft^3 (Moore and Sigler, 1987). Associated gas from the Bluebell field (table 6-3) contains an average of 85% methane, 8% ethane, 3% propane, 2.6% higher fractions, 0.3% CO_2, with an average heating value of 1200 Btu/ft^3 (Moore and Sigler, 1987). For additional information on geochemical analysis and biomarker studies of the Green River oils, please refer to Ruble, 1996; Mueller, 1998; Mueller and Philp, 1998; Ruble and Philp, 1998; and Dubiel, 2003.

Production

Fields in the CNUBP produce crude oil and associated gas. Production from the Conventional Bluebell subplay cannot be accurately separated from the DUBOCP and is

presented as production for that play. The largest fields (fields with >500,000 bbls of oil [79,500 m^3] cumulative production) in the Conventional Red Wash subplay have produced 160.8 million BO (25.6 million m^3) and 499.8 BCFG (14.2 BCMG) as of January 1, 2008. Monthly production from the play in December 2007 was 85,000 BO (13,515 m^3) and 637 MMCFG (15.2 MMCMG) (Utah Division of Oil, Gas and Mining, August 1, 2008). The Red Wash field has produced the most oil and continues to be the largest producer in the subplay. The OOIP estimate for Red Wash and Wonsits Valley (the two most productive fields in the Conventional Red Wash subplay) are 550 million BO (87.5 million m^3) and 149 million BO (23.7 million m^3), respectively (Mary McPherson, verbal communication, 1998). The estimated ultimate recovery (EUR) for Red Wash and Wonsits Valley fields was 106 million BO (16.9 million m^3) and 48 million BO (7.6 million m^3), respectively (Schuh, 1993a, 1993b). As of August 1, 2008, the cumulative production from Red Wash and Wonsits Valley fields was 351 million BO (55.9 million m^3) and 101 million BO (16.1 million m^3), respectively (Utah Division of Oil, Gas and Mining, August 1, 2008). Both fields have exceeded their original EUR, newer OOIP and EUR calculations for the two fields have not been published. Data on production and number of wells are summarized for the fields in the play in table 7-1.

Exploration Potential and Trends

Conventional Bluebell Subplay

Infill drilling will continue in portions of the Altamont-Bluebell-Cedar Rim field area (figure 7-1) where the Conventional Bluebell subplay play has not been developed two wells per section. Down spacing to four producing wells per section was approved by the Utah Board of Oil, Gas and Mining in December, 2008 and could result in hundreds of new wells. The increased well density could eventually lead to EOR in portions of the Altamont-Bluebell-Cedar Rim fields.

The western portion of the Conventional Bluebell subplay is being explored for Mesaverde Group and Mancos Shale gas. The deeper drilling for gas could result in the discovery of new oil fields in the overlying Green River Formation.

Secondary and tertiary recovery methods have not been attempted in the Altamont-Bluebell-Cedar Rim field area. Several factors have discouraged operators from attempting any secondary recovery pilot projects. Fractures in the reservoir rock can cause early breakthrough of any injected fluid or gas. Fractures can result in injected fluids or gases moving great distances, perhaps even beyond the intended secondary recovery unit. Secondary and tertiary recovery methods generally require a high density of wells to be effective. The Altamont-Bluebell-Cedar Rim field area has been developed with two wells per section and in many areas at least one of those wells has already been plugged and abandoned. As a result, any secondary or tertiary recovery method would require a significant amount of additional drilling. Allowing the production of four wells per section will be a significant step in improving the understanding of the reservoir and potential development of EOR.

The gross productive interval is 1000+ feet (300 m) thick, with no single bed being a dominant producer. As a result, horizontal drilling has not been attempted in the Altamont-Bluebell-Cedar Rim fields. High angle well bores have been drilled in an attempt to encounter thicker productive beds and intersect more fractures. The high angle wells were expensive to

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Conventional Red Wash Subplay

Many of the fields in the Conventional Red Wash subplay are currently in secondary recovery waterflood operations and are not actively being drilled. Long-reach horizontal wells in the Wonsits Valley field are being drilled into the G limestone of the Green River Formation resulting in increased production from the field. As a result, annual oil production from the Wonsits Valley field increased in 2006 and 2007 after years of decline. Tertiary recovery techniques are not currently being tested, but may be considered in the future as production continues to decline. A pilot CO_2 injection test was conducted in the Red Wash and Wonsits Valley fields in the 1980s. The short injection tests had mixed results and no further testing was done. Much of the Conventional Red Wash subplay area is being actively explored for gas in the deeper Wasatch Formation, Mesaverde Group, and Mancos Shale. The deep drilling will likely identify new potential in the shallow Green River Formation that can be exploited in the wells when the deeper reservoirs are depleted or may lead to additional development drilling if the Green River potential is considered significant.

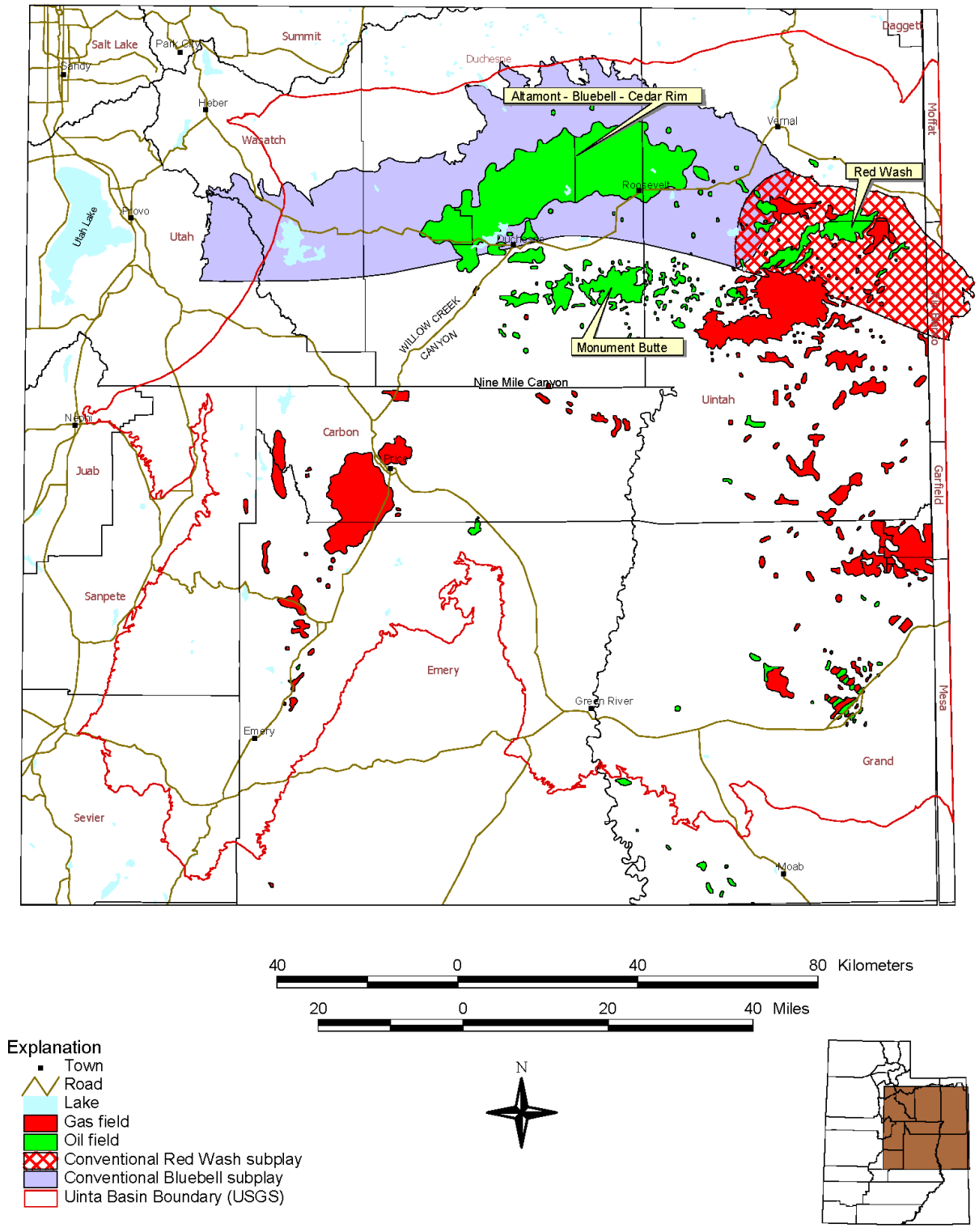


Figure 7-1. Location map showing the outline of the Uinta Basin and major oil and gas fields. Blue and cross-hatched areas are the Conventional Bluebell subplay and the Conventional Red Wash subplay respectively, that make up the Conventional Northern Uinta Basin play.

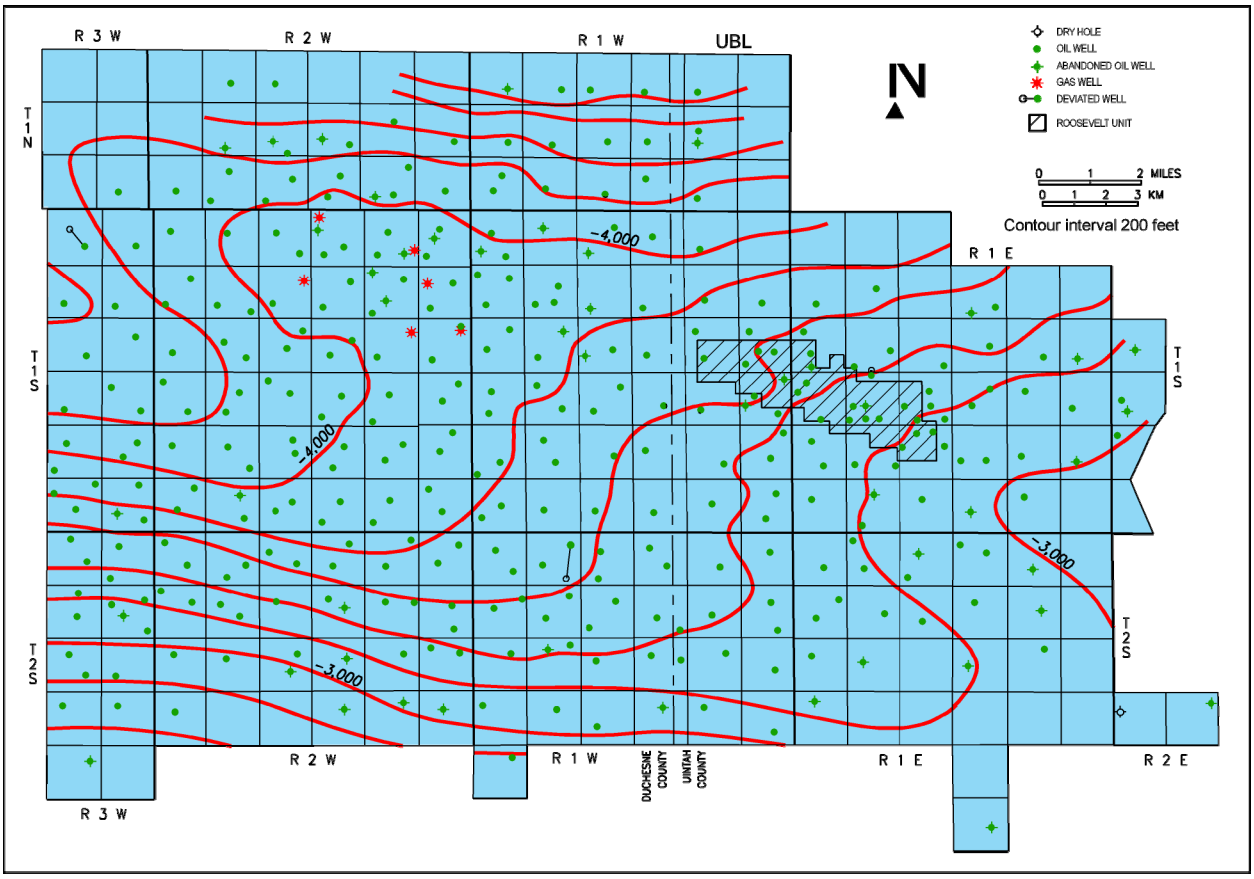


Figure 7-2. Structure contour map of the top of the middle marker of the Green River Formation, Bluebell field, Duchesne and Uintah Counties, Utah. Contour interval is 200 feet; datum = mean sea level. From Morgan (2003b).

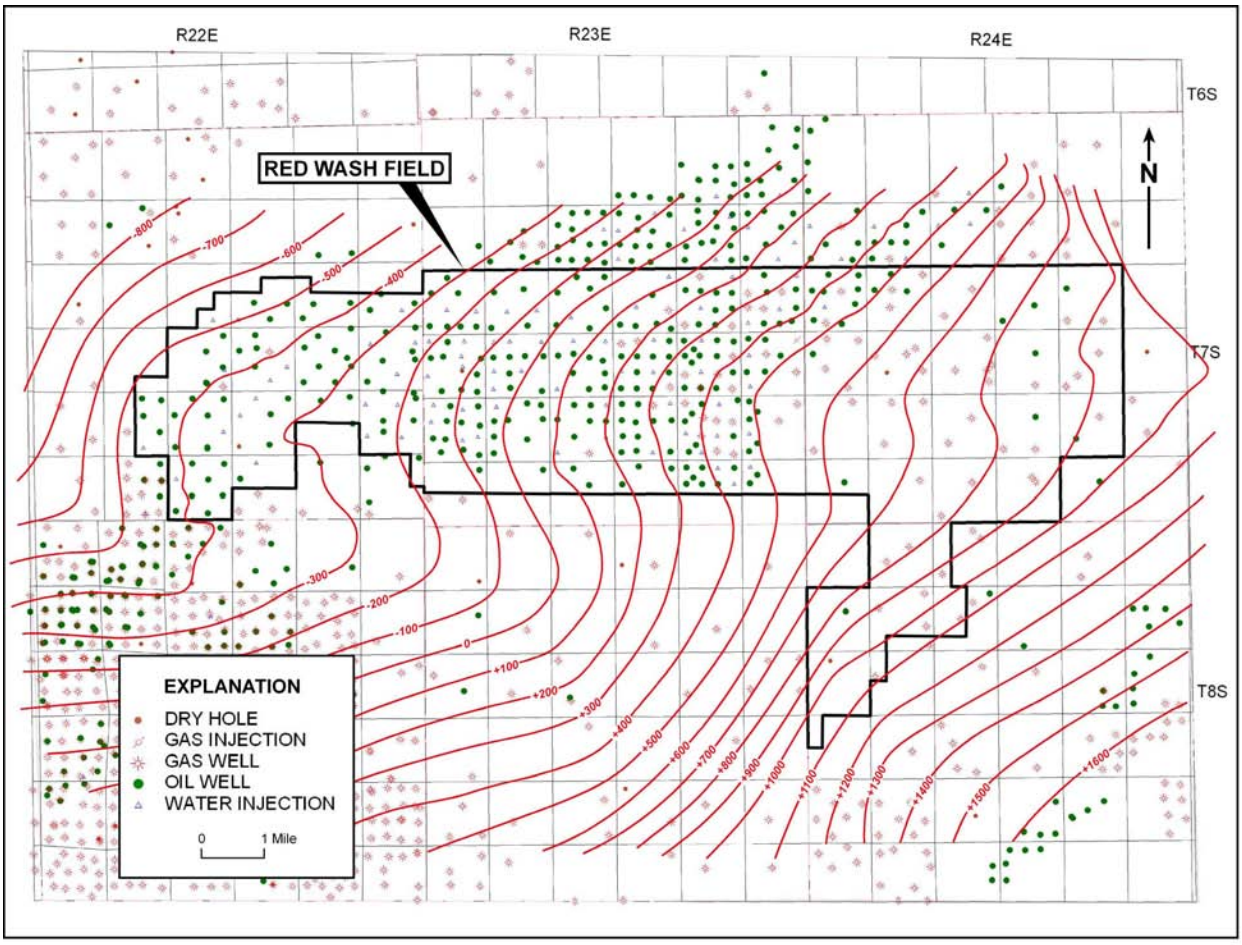


Figure 7-3. Structure contour map on the top of the Douglas Creek Member of the Green River Formation, Red Wash field. Contour interval is 100 feet; datum = mean sea level. From Schuh (1993a).

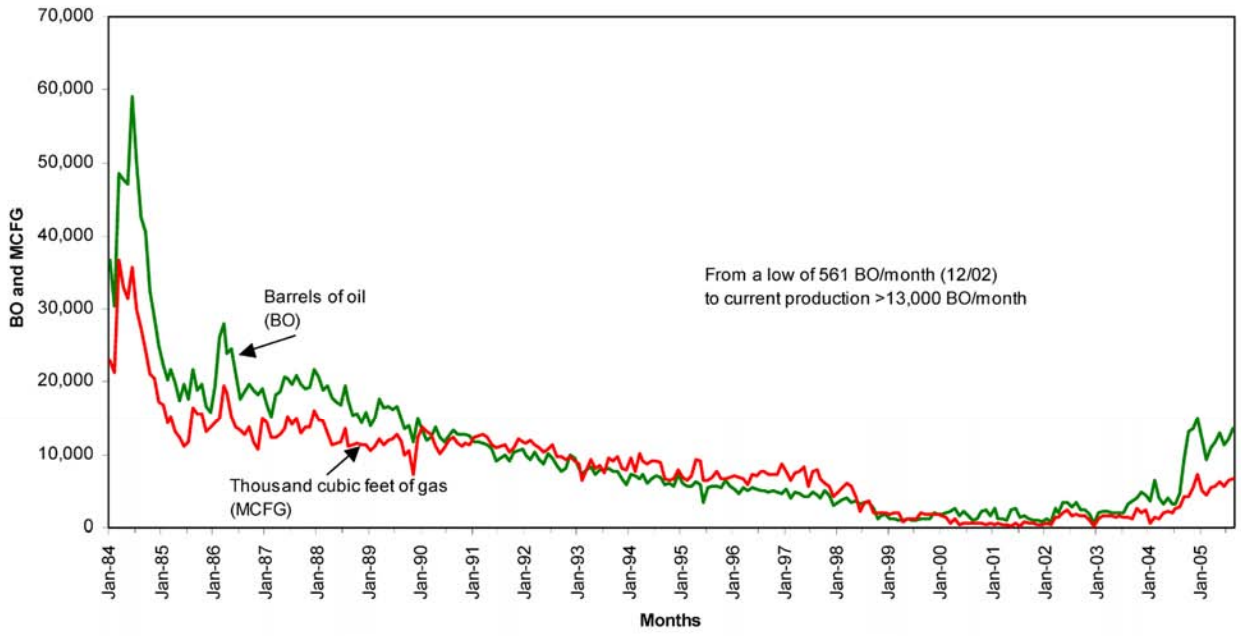


Figure 7-4. Monthly oil and gas production for the Roosevelt unit in the Bluebell field. Production from the unit had dropped to a low of 561 BO/month in December 2002, but a recent program of recompletions has increased production to more than 13,000 BO/month. This is an example of the potential that still exists in the Conventional Northern Uinta Basin play. Data from Utah Division of Oil, Gas and Mining, 2008.

Table 7-1. Geologic, reservoir, and production data for the largest fields in the Conventional Red Wash subplay of the Conventional Northern Uinta Basin play. Data for the Conventional Bluebell subplay can not be accurately separated from the Deep Uinta Basin Overpressured Continuous play, and is presented in that play see; table 6-1. Production data is from Utah Division of Oil, Gas and Mining (2008).

State	County	Field	Discovery Date	Active Producers	Abandoned Producers	Acres	Spacing (acres)	Pay (feet)	Porosity (%)	Perm. (mD)	Temp. (°F)	Initial Reservoir Pressure (psi)	Monthly Production		Cumulative Production	
													Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
Utah	Uintah	Brennan Bottom	1954	8	3	1760	160	26	12	1.0	162	2580	2,508	1,800	1,709,082	2,256,049
Utah	Uintah	Coyote Basin	1964	21	3	1600	80	8	14	215	120	1559	2,334	2,107	1,913,057	904,908
Utah	Uintah	Red Wash	1951	116	21	31,000	40-80	170	13	42	149	1925	36,537	89,623	81,832,186	344,401,518
Utah	Uintah	Walker Hollow	1953	85	11	9040	40	NA	13	42	107	NA	18,481	43,354	18,390,619	32,023,832
Utah	Uintah	White River	1964	4	2	1040	80	16	10	NA	150	2379	608	73,864	2,750,780	9307,231
Utah	Uintah	Wonsits Valley	1962	56	58	6240	40	90	12	22	149	2800	31,726	606,221	49,393,480	85,692,422

NA = data not available.

CHAPTER 8
CONVENTIONAL SOUTHERN UINTA BASIN PLAY

Craig D. Morgan,
Utah Geological Survey

Introduction

The Conventional Southern Uinta Basin play (CSUBP) covers the central and southern Uinta Basin (figure 8-1) and typically has drill depths ranging from 3000 (900 m) to 6500 feet (2000 m). The play is divided into six subplays: (1) Conventional Uteland Butte Interval subplay, (2) Conventional Castle Peak Interval subplay, (3) Conventional Travis Interval subplay, (4) Conventional Monument Butte Interval subplay, (5) Conventional Beluga Interval subplay (Morgan and Bereskin, 2003), and (6) Conventional Duchesne Interval Fractured Shale/Marlstone subplay (figures 2-11 and 8-2).

The southern shore of Lake Uinta was often very broad and flat, which resulted in laterally extensive transgressions and regressions of the shoreline in response to climatic and tectonic-induced rise and fall of the lake (figure 2-12). The cyclic nature of Green River deposition in the central Uinta Basin resulted in numerous stacked deltaic deposits. Distributary-mouth bars, distributary channels, and nearshore bars are the primary producing reservoirs in the area (figure 2-17).

The changing depositional environments of Paleocene-Eocene Lake Uinta controlled the characteristics of each interval and the reservoir rock contained within. The Travis reservoir records a time of tectonism that created a steeper slope and a pronounced shelf break where thick cut-and-fill valleys developed during lake-level falls and rises. The Monument Butte reservoir represents a return to a gentle, shallow shelf where channel deposits are stacked in a lowstand delta plain and amalgamated into the most extensive reservoir in the central Uinta Basin. The Beluga reservoir represents a time of major lake expansion with fewer, less pronounced lake-level falls, resulting in isolated single-storied channel and shallow-bar sand deposits. The fractured shale/marlstone rocks in the upper part of the middle member, the upper member, and the saline member of the Green River Formation were deposited during the maximum rise and waning stages of Lake Uinta.

Depositional Environment

The CSUBP produces from the Eocene Green River Formation. The reservoir in the Uteland Butte interval is mainly lacustrine limestone with rare bar sandstone beds, whereas the reservoirs in the overlying four intervals are mainly distributary channel and shallow lacustrine sandstone beds (Morgan and Bereskin, 2003; Morgan and others, 2003).

The Uteland Butte interval was deposited during a major rise in lake level representing the first major transgression of the lake after deposition of the alluvial Colton Formation. The Uteland Butte is distinctive in its abundance of carbonate rocks and lack of sandstone, which could have been caused by one or both of the following situations: (1) the rapid lake-level rise caused siliciclastic sediments to be deposited in proximal alluvial channels, or (2) the main sediment inflow into the lake was far from the central Uinta Basin area, perhaps flowing into the southern arm of the lake south and west of the San Rafael uplift (McDonald, 1972). Little

(1988), working in the Minnie Maud Creek to Willow Creek Canyon area, described the Uteland Butte environment as shallow-water mud flats to offshore lacustrine. Little (1988) describes 3- to 6-foot (1-2 m) thick beach- or bar-sandstone beds in the Minnie Maud area, but these beds are absent in Willow Creek Canyon (figure 8-1).

The Castle Peak in the central Uinta Basin consists of isolated marginal lacustrine channel sandstone beds encased in carbonate that were deposited during a time of numerous and rapid lake-level fluctuations, which developed a simple drainage pattern across the exposed shallow and gentle shelf with each fall and rise cycle (figure 2-17). These channel deposits are typically limited in lateral extent; channel stacking is rare. The lack of channel stacking is attributed to short-duration cycles of lake-level rise and fall. As a result, the drainage system for each cycle never advanced beyond the initial stage. Schumn and Ethridge (1994) show that the initial drainage pattern on an exposed shelf is typically a series of subparallel, unconnected channels.

The Travis interval consists of sand-rich alluvial and deltaic deposits of the Renegade Tongue (Cashion, 1967) in Desolation Canyon, fluvial-deltaic deposits in Nine Mile Canyon, and the green shale facies (Picard, 1955, 1957) in Willow Creek Canyon. This represents a significant basinward shift of facies. In the Monument Butte area, however, the rocks consist of the black shale facies and do not show evidence of a major regression. A significant basinward shift of the shoreline without evidence of shallowing, and perhaps even deepening in the distal reaches, may be the result of tectonic movement in the basin. This tectonic activity may have shifted the regional drainage to the central Uinta Basin area, resulting in the sand–rich deltaic deposits in Desolation and Nine Mile Canyons. Prior to this tectonic activity, channel deposits in the lower member of the Green River Formation in the central Uinta Basin were generally smaller and more isolated, indicating only a local drainage system. Also, a relatively prominent shelf break developed at this time in the Monument Butte area. Many of the oil-productive sandstone beds in the Travis interval are channel and shallow bar deposits. The primary reservoirs in the Travis are turbidite and shallow lacustrine sandstone beds deposited in narrow cut-and-fill valleys along the shelf break during several lake level fall-and-rise cycles. The Travis is the only stratigraphic interval in the lower or middle members where there is evidence of a sharp shelf break in the central area. Lutz and others (1994) described the Travis reservoir as moderate- to low-density turbidite channel, debris flow, and gravity flow deposits.

The Monument Butte is the primary oil-producing interval in the central Uinta Basin. The reservoir consists of amalgamated channel and distributary-mouth bar sandstone deposited on the distal, lower delta plain of Lake Uinta when the lake was at a low level, with an area of sediment bypass forming the updip trap (Morgan and others, 2003).

The Beluga interval was deposited during a time of overall lake-level rise, and is transitional from the underlying delta facies in the Douglas Creek Member to the overlying deep-lake oil shale deposits of the upper member. This trangressive facies deposition resulted in less total sandstone and more common individual, isolated channel and bar deposits.

Stratigraphy and Thickness

The Green River Formation is generally 4000 feet (1200 m) to 5500 feet (1700 m) thick in the central Uinta Basin. The majority of the production comes from the lower Green River a 2000-foot-thick (600 m) gross productive interval (figure 2-16) with minor production from a poorly defined interval of fractured shale and marlstone in the upper Green River.

The Uteland Butte interval is defined as the stratigraphic interval from the top of the Colton Formation to the top of LGR 5, a log marker defined by Morgan and others (1999). The Uteland Butte is equivalent to the first lacustrine tongue of Bradley (1931), lower black shale facies of Abbott (1957), basal limestone facies of Little (1988) and Colburn and others (1985), Uteland Butte limestone of Osmond (1992), and basal limestone member of Crouch and others (2000). The black shale facies described by Wiggins and Harris (1994) includes the Uteland Butte and overlying Castle Peak intervals. The Uteland Butte interval ranges in thickness from less than 60 feet (20 m) to more than 200 feet (60 m) in the central Uinta Basin generally from a drill depth range of 4500 feet (1400 m) to 6500 feet (2000 m) (figure 2-16).

The Castle Peak interval (figures 2-11 and 2-16) is defined as the stratigraphic section from the top of the Uteland Butte to the top of the carbonate marker bed of Ryder and others (1976). It is equivalent to the Wasatch (Colton) tongue and second lacustrine tongue of Bradley (1931), the Colton tongue and carbonate marker unit of Ryder and others (1976), and is included in Picard's (1955) black shale facies. The alluvial Colton tongue is exposed in Willow Creek and Nine Mile Canyons but extends only a few miles north. Above the Colton tongue, the Castle Peak consists of interbedded black shale, limestone, and limy mudstone, with some sandstone and siltstone.

The Travis interval is defined as the stratigraphic section from the top of the lower member of the Green River Formation (carbonate marker bed) to the top of the MGR 3 marker (figures 2-11 and 2-16). The interval is part of the middle member and ranges in gross thickness from 270 feet (80 m) to 700 feet (200 m) in the central Uinta Basin (Morgan and Bereskin, 2003; Morgan and others, 2003).

The Monument Butte interval is defined as the stratigraphic section from the top of the MGR 3 marker (Travis reservoir) to the top of the MGR 7 marker (figures 2-11 and 2-16). The interval ranges in thickness from 250 feet (75 m) to almost 500 feet (150 m) in the central Uinta Basin (Morgan and Bereskin, 2003; Morgan and others, 2003).

The Beluga interval is defined as the stratigraphic section from the top of the MGR 7 to the top of the MGR 18 (figures 2-11 and 2-16). The interval ranges in thickness from 550 feet (170 m) to more than 1200 feet (370 m) in the central Uinta Basin (Morgan and Bereskin, 2003; Morgan and others, 2003).

The Duchesne interval is defined as the stratigraphic section from the MGR 18 to the top of the Green River Formation, which includes part of the middle member and all of the upper and saline members of the Green River Formation (figures 2-11 and 2-16).

Lithology

The dominant oil-productive lithology is sandstone with lesser amounts produced from carbonates and fractured shales and marlstones. Production is primarily from lower Green River Formation marginal lacustrine distributary channels, with some production from turbidite and slump deposits (Lutz and others, 1994; Bereskin and others, 2004), and minor production from lacustrine carbonate mudstone and grainstone.

The Uteland Butte reservoir consists of carbonate and rare, thin, shallow-lacustrine sandbars deposited during the initial rise of the lake. The Uteland Butte lithologies are dolomitized ostracod and pellet grainstone and packstone, and pelecypod-gastropod sandy grainstone interbedded with silty claystone or carbonate mudstone. Most of the Uteland Butte interval production is from low permeability limestone and dolostone that may contain minor

fractures enhancing reservoir quality.

The Castle Peak sandstone is typically medium grained (0.36 to 0.44 mm), poorly to moderately sorted, angular to very well rounded, mostly lithic arkose or feldspathic litharenite. Lithics are mostly chert but include metamorphic, granitic, and volcanic rock fragments. Most of the other sandstone beds in the Green River Formation are very fine to fine grained. Framework elements of the Castle Peak sandstone include: (1) monocrystalline and polycrystalline quartz, (2) potassium feldspar (orthoclase and microcline), (3) plagioclase, (4) chert, (5) sheared metaquartz, recrystallized metaquartz, and hydrothermal quartz, (6) intrusive rock fragments, (7) dolomite, siltstone and mudstone clasts, (8) carbonate ooids, (9) isolated mica booklets (biotite, chlorite, and muscovite), (10) some red-brown hematite staining, and (11) assorted heavy minerals such as zircon, epidote, tourmaline, sphene, and rare amphibole. The Castle Peak sandstone is typically highly compacted with extensive quartz and some feldspar cementation.

Two rock types comprise the majority of the sandstone beds in the Travis reservoir. Rock-type T-1 is a very poorly sorted combination of silt and very fine grained sand that commonly contains detrital clay coatings around many of the grains as well as large clasts of highly compacted dolomitic and illitic mudstone. It typically has poor porosity and permeability due to tight grain packing, sporadic detrital clay coatings, and pseudomatrix formation of mudstone clasts. Rock-type T-2 is a laminated assemblage of very fine to fine-grained sandstone that has the appearance of a chaotic breccia of haphazardly distributed carbonate mudstone clasts in a poorly sorted silt to very fine grained matrix with abundant soft-sediment-deformation features. Fractures in the Travis reservoir sandstone are rare due to the clay content reducing the overall brittleness of the beds.

Two rock types also comprise most of the sandstone beds in the Monument Butte reservoir. Rock-type MB-1 is the most abundant and is typically very fine to fine grained (median 0.11 to 0.17 mm), moderately well sorted to well sorted, with subangular to subrounded grains. The framework assemblage is similar in composition and abundance to the medium-grained sandstone in the Castle Peak, except the rock-type MB-1 has more biotite, chlorite, and muscovite. Also, in rock-type MB-1 the mudstone fragments are dolomitic, ankeritic, and carbonate allochems including ankeritic/dolomitic ooids, ankeritic/dolomitic rip-ups, ostracods, or intraclasts. Rock-type MB-2 is sandstone consisting of very fine grained sand and coarse silt with increased clay content compared to MB-1. Rock-type MB-2 is a ripple-drift lamination facies found in the upper portion of fining-upward sandstone sequences. Compared to MB-1, it is more poorly sorted, angular to subangular, and has more grains coated with illite. It also contains more mica, especially muscovite, than the rock-type MB-1 sandstone.

The Beluga interval consists of interbedded sandstone, shale, and limestone. The sandstone in the Beluga reservoir is similar in composition to the Monument Butte reservoir sandstone. There are fewer fining-upward sequences and therefore less rock-type MB-2 ripple-drift laminated facies.

The Duchesne interval fractured shale/marlstone subplay consists of shale (including oil shale), marlstone, and rare sandstone. Oil is stored in naturally occurring fractures in the shale and marlstone beds.

Hydrocarbon Source and Seals

The source rocks for the crude oil produced from the CSUBP are kerogen-rich shale and marlstone of the Green River Formation, which were deposited in nearshore and offshore open-lacustrine environments (Hunt and others, 1954; Forsman and Hunt, 1958; Silverman and Epstein, 1958; Tissot and others, 1978; Ruble, 1996; Ruble and others, 1998). Based on burial history and petroleum-generation modeling of the Shell Brotherson 1-11B4 well in the Altamont field, Dubiel (2003) determined that oil and gas generation began near the base of the Green River around 40 Ma at a depth of 11,000 feet (3300 m). Peak generation occurred during maximum burial between 30 to 40 Ma. The zone of hydrocarbon generation has risen stratigraphically through time (Dubiel, 2003). Mueller (1998) reports that fields in the CSUBP were charged from local unidentified sources with in some cases, a possible contribution from the upper black shale facies.

Vertical and horizontal seals for producing zones are unfractured shale and low-permeable marls within the Green River Formation.

Structure and Trapping Mechanisms

Stratigraphic traps are the primary trapping mechanism for reservoirs in the CSUBP. Structure is dominantly regional dip northward into the basin with minor flexures or plunging structural anticlinal trends with no four-way closure. The downdip (northern) extent of the CSUBP is not defined. Locations downdip are deeper and encounter a more distal facies of the Green River Formation. As a result, the sandstone beds are often more isolated, thinner and may have reduced reservoir quality due to greater compaction. The updip (southern) extent of the field has been more extensively drilled. As drilling moves updip more of the sandstone beds are water bearing. The updip trapping mechanism is not understood. One possibility is the productive sandstones are pinching out updip and the water-bearing sandstones are deposits of a more proximal marginal-lacustrine facies, representing different parasequences.

Reservoir Properties

Oil and gas production in the CSUBP is mostly from the middle and lower Green River Formation with minor amounts produced from the upper Green River (Weiss and others, 1990). Reservoir data for individual fields in the CSUBP are summarized in table 8-1. The reservoir rocks are low permeability, 0.1 to 10 mD, rarely 50 mD or more; porosity ranges from 8% to 20%. Original reservoir pressure is near bubble point, but when pressure drops below the bubble point, gas begins to breakout within the reservoir greatly reducing the oil recovery. As a result, many wells in the Greater Monument Butte field (figure 8-1) are produced for only a year or less before they are converted to waterflood to help maintain reservoir pressure above the bubble point as well as provide a sweep of the oil.

The primary control on reservoir quality is the complex diagensis of individual sandstone beds, which has been described by Bereskin and others (2004). For example, in the Monument Butte reservoir, some of the MB-1 sandstone had early cementation with iron-poor calcite, which greatly reduced the effects of compaction. Later dissolution of the iron-poor calcite resulted in some beds with permeabilities in the tens of mD and porosity more than 20%. Other sandstone had a later stage of cementation with dolomite, ankerite, siderite, and iron-rich calcite, which

greatly reduced the rock pore space. Partial dissolution of the late-stage cement restored some of the reservoir potential of the rock, resulting in greater than 10% porosity but less than 20 mD permeability. Examination of rock-type MB-2 sandstone shows that severe compaction occurred soon after deposition, which resulted in abundant microstylolite development. Rarely is early iron-poor calcite cement found in rock-type MB-2. Dissolution of feldspars is minor, resulting in low porosity (<10%) and low permeability (<0.1 mD).

Fractures are important to the economic success of the Castle Peak Interval and Uteland Butte Interval subplays because of the low matrix permeability typically found in these intervals. Porosity in the Castle Peak Sandstone is typically the result of dissolution of feldspars and some rock fragments. However, fractures in the sandstone are necessary for good hydrocarbon production and are most commonly developed at the base of the bed where the carbonate content is highest, which results in increased brittleness. The Travis Interval, Monument Butte Interval, and Beluga Interval subplays are not fracture dependant but production is enhanced when fractures are encountered. The Travis reservoir typically has low porosity and permeability due to tight grain packing, illite coating the grains, and a general lack of secondary intergranular pores. The Duchesne Interval Fractured Shale/Marlstone subplay is entirely dependant on naturally occurring fractures in the upper member of the Green River Formation for economic production. Most of this interval is at shallow drill depths in the basin. As a result, the formation temperatures are often near or below the pour-point temperature of the oil, making it a difficult reservoir to exploit.

The gross productive interval in the CSUBP can be more than 1000 feet (300 m) but the net productive interval is typically tens of feet to more than 100 feet (30 m). Not all of the intervals that make of the subplays are productive in every well. Most of the individual beds that are perforated have a thickness of feet to a few tens of feet.

Oil and Gas Characteristics

Most of the oil produced from the CSUBP is characterized as black wax (table 6-2). The black wax typically has a gravity of 28° to 34°API gravity with a pour point from 90°F (32°C) to 120°F (49°C). Associated gas from the CSUBP has a heating value of more than 1100 Btu/ft^3. Associated gas from the Monument Butte 10-35 well (table 6-3) contains 71.8% methane, 14.9% ethane, 9.9% propane, and 3.3% higher fractions (Moore and Sigler, 1987).

Production

Fields in the CSUBP produce crude oil and associated gas. The nine largest fields in the play (fields with >500,000 bbls of oil [79,500 m^3] cumulative production) have produced 61.9 million BO (9.8 million m^3) and 192.1 BCFG (5.4 BCMG) as of August 1, 2008. Monthly production for 2008 from these fields in the play was 508,000 BO (80,772 m^3) and 2.3 BCFG (0.05 BCMG) (Utah Division of Oil, Gas and Mining, August 1, 2008). Data on production and number of wells are summarized for the fields in the play in table 8-1.

Exploration Potential and Trends

The Uteland Butte interval is rarely a primary target due to the poor oil recovery from the low permeability reservoir. Most operators drilling for the Castle Peak Interval and other

overlying subplays can test the Uteland Butte by drilling an additional 100 feet (30 m) to 200 feet (60 m). The typical oil recovery (10s of thousands of barrels) is sufficient to justify the cost to drill the additional depth. Uteland Butte Interval subplay will expand with the expansion of the overlying subplays. Current drilling, which should continue for many years, will expand the Brundage Canyon field to the west, the Greater Monument Butte field (Monument Butte, Eight Mile Flat North, and Pariette Bench fields) to the east, and both fields to the north.

The Castle Peak, Travis, Monument Butte, and Beluga intervals are drilled and completed together. Each interval may be the primary reservoir in certain portions of the play, but no interval is completed by itself. As a result, the exploration potential and trend is the same for all of the subplays (figure 8-1). Current drilling, which should continue for many years, will expand the Brundage Canyon field to the west, the Greater Monument Butte field (Monument Butte, Eight Mile Flat North, and Pariette Bench fields) to the east, and both fields to the north.

In the southern Uinta Basin the Green River Formation, and all associated subplays, is deeply incised and at shallow depths where the current reservoir temperature is below the pour point of the oil (figure 8-1). As a result, the potential reservoirs will contain heavy oils or tar that require thermal recovery or some other unconventional recovery technique.

The Duchesne Interval Fractured Shale/Marlstone subplay is restricted to the Duchesne field. This subplay is not currently being explored due to the low volume of oil recovered and the difficulty in predicting the location of economically productive fractures. Development of the deeper intervals include penetration of the shallower Duchesne interval. As a result, fracture trends or “sweet spots” may be discovered that could lead to exploitation.

The Monument Butte area is still being activity developed. It will take about 10 to 15 years to fully develop the field on 40-acre (16.2-ha) spacing at the current rate of drilling. Recent drilling spaced at 20 acres (8.1 ha) per well has successfully tapped banked oil, found new pay, improved sweep efficiency, and accelerated recovery from the Monument Butte waterflood. Infill drilling could result in 1000 more locations extending the drilling to 30 years at current levels (Morgan, 2008). The Brundage Canyon field with more than 400 producing wells is not currently under waterflood (Kelso and Ehrenzeller, 2008). Both the Monument Butte area and the Brundage Canyon field may some day be good candidates for tertiary recovery such as CO_2 flooding.

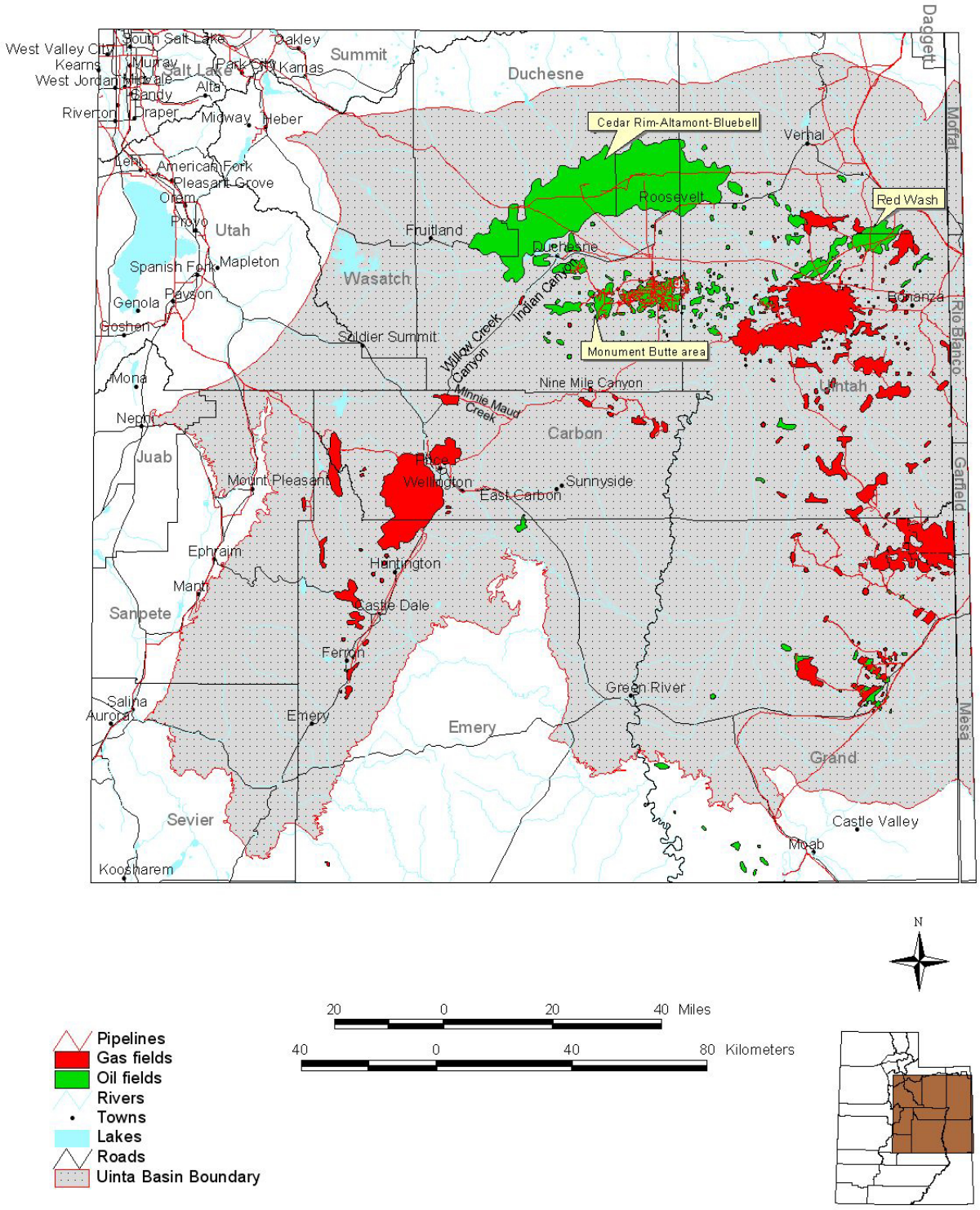


Figure 8-1. Location map showing the outline of the Uinta Basin, major oil and gas fields, and the Conventional Northern Uinta Basin play and Conventional Southern Uinta Basin play areas. The two plays overlap because the north-sourced deposits and the south-sourced deposits of the Green River Formation intertongue in the central basin.

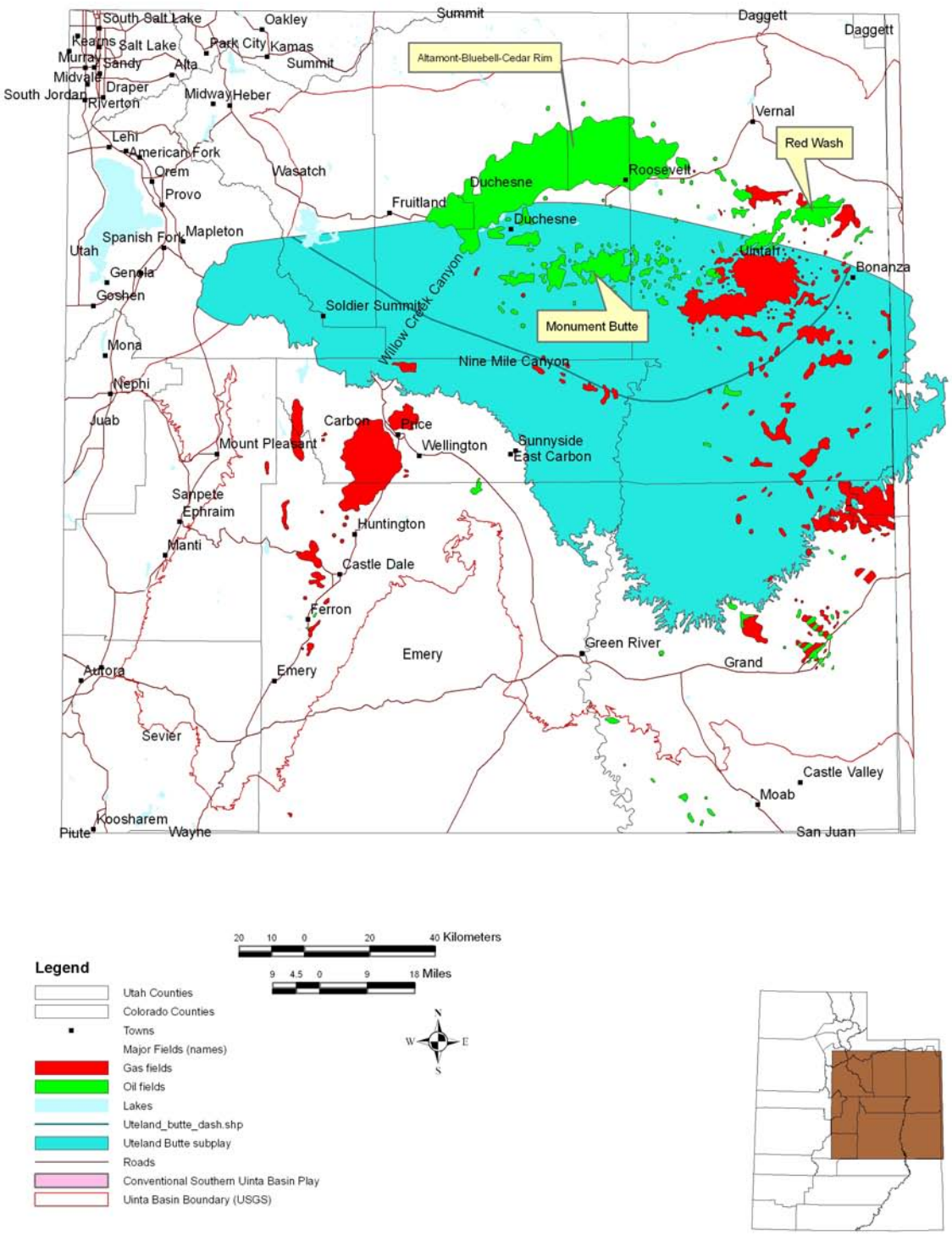


Figure 8-2. Location map showing the outline of the Uinta Basin, major oil and gas fields, and the Conventional Southern Uinta Basin play area. The subplays encompass the entire Conventional Southern Uinta Basin play area. The solid crescent-shaped line dividing the play into a northern and southern area is the approximate updip boundary where the formation temperature in the CSUBP is near the pour-point temperature of the oil. As a result, the area updip (south) of this line may not have moveable oil in the reservoir.

Table 8-1. Geologic, reservoir, and production data for the largest fields in the Conventional Southern Uinta Basin play. Most of the fields are being actively developed, ever expanding the number of active producers and acres. Most of the data is from Hill and Bereskin (1993). Production data from Utah Division of Oil, Gas and Mining (2008).

Stat	County	Field	Discovery Date	Active Producer	Abandoned Producers	Acres	Spacing (acres)	Pay (feet)	Porosity (%)	Perm (mD)	Temp (^{o}F)	Initial Reservoir Pressure (psi)	Monthly Production		Cumulative Production	
													Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
Utah	Duchesne	Antelope Creek	1963	106	1	1760	40	40	13	8	130	2400	17,160	14,732	5,694,945	14,011,360
Utah	Duchesne	Brundage Canyon	1983	462	NA	16,880 +	40	30	11	0.1	120	1700	135,744	1,001,683	12,026,443	53,100,362
Utah	Duchesne	Duchesne	1951	22	6	760	40	Variable	13	8	165	NA	1161	295	1,386,920	2,980,571
Utah	Uintah	Eight Mile Flat North	1695	265	6	10,600 +	40	25	15	NA	140	2000				
Utah	Duchesne and Uintah	Monument Butte	1981	883	NA	100,000	40-20	16	15	25	150	2150	333,006	427,471	35,523,139	87,910,918
Utah	Uintah	Pariette Bench	1962	63	NA	2000+	40	NA	NA	NA	NA	NA	2647	519,331	1,272,237	16,179,098
Utah	Uintah	Uteland Butte	1962	43	1	5640	40	20	10	<1.0	NA	NA	6017	93,283	1,436,612	3,566,427
Utah	Uintah	West Willow Creek	1981	7	NA	1240	80	100	18	89	NA	NA	988	24,676	1,069,871	10,782,344
Utah	Uintah	Windy Ridge	1988	21	0	1720	40	50	NA	NA	NA	NA	2725	2950	1,091,524	1,581,520

NA = data not available

CHAPTER 9
MISSISSIPPIAN LEADVILLE LIMESTONE PARADOX BASIN PLAY

Thomas C. Chidsey, Jr.,
Utah Geological Survey

Introduction

The Mississippian Leadville Limestone is one of two, major oil and gas plays in the Paradox Basin, the other being the Pennsylvanian Paradox Formation (figure 9-1). Most Leadville production is from the Paradox fold and fault belt (figure 9-2). The Leadville Limestone has produced over 53 million barrels (8.4 million m^3) of oil and 845 billion cubic feet (BCF [23.9 billion m^3]) of gas from the six fields in the northern Paradox Basin of Utah and Colorado (Utah Division of Oil, Gas and Mining, 2008; Colorado Oil and Gas Conservation Commission records). However, much the gas included in the production figures is cycled gas used in the past for pressure maintenance at Lisbon field, Utah. The 7500-mi^2 (19,400 km^2) play area is relatively unexplored; only about 100 wells penetrate the Leadville (less than one well per township), thus the potential for new discoveries remains great. Geologic data for individual fields in the play are summarized in table 9-1.

The play outline represents the maximum extent of petroleum potential in the geographical area as defined by producing reservoirs, hydrocarbon shows, and untested hypotheses. The attractiveness of the Leadville Limestone Paradox Basin play (and other Paradox Basin plays) to the petroleum industry depends on the likelihood of successful development, reserve potential, pipeline access, drilling costs, oil and gas prices, and perhaps most significantly in the Paradox Basin, environmental concerns. When evaluating these criteria, certain aspects of the Leadville play may meet the exploration guidelines of major oil companies while other aspects meet the development guidelines of small, independent companies.

Depositional Environment

The Mississippian (late Kinderhookian through Osagean to early Meramecian time) Leadville Limestone is a shallow, open marine, carbonate-shelf deposit (figure 9-3). Local depositional environments included shallow-marine, subtidal, supratidal, and intertidal (Fouret, 1982, 1996). The western part of the Paradox fold and fault belt includes a regional, reflux-dolomitized, interior bank facies containing Waulsortian mounds (Welsh and Bissell, 1979) - local, mud-supported buildups involving growth of “algae” (Wilson, 1975; Ahr, 1989; Fouret, 1982, 1996).

During Late Mississippian time, the entire carbonate platform in southeastern Utah and southwestern Colorado was subjected to subaerial erosion resulting in formation of a lateritic regolith (Welsh and Bissell, 1979). This regolith and associated carbonate dissolution is an important factor in Leadville reservoir potential (figure 9-4). Solution breccia and karstified surfaces are common, including possible local development of cavernous zones (Fouret, 1982, 1996).

Periodic movement along northwest-trending basement faults affected deposition of the Leadville Limestone. Crinoid banks or mounds, the primary reservoir facies, accumulated in

shallow-water environments on upthrown fault blocks or other paleotopographic highs. In areas of greatest paleorelief, the Leadville is completely missing as a result of non-deposition or subsequent erosion (Baars, 1966).

There are four Leadville depositional facies based on cores from Lisbon field (figure 9-2): open marine, shoal flank, restricted marine, and middle shelf. Open-marine facies are represented by crinoidal banks or shoals and Waulsortian-type buildups (figure 9-3). This facies represents a high-energy environment with well-circulated, normal-marine salinity water in a subtidal setting. Water depths ranged from 5 to 45 feet (1.5-14 m). Waulsortian buildups or mud mounds developed exclusively during the Mississippian in many parts of the world (Wilson, 1975). They are steep-sloped tabular, knoll, or sheet forms composed of several generations of mud deposited in a subtidal setting (Fouret, 1982, 1996; Lees and Miller, 1995) (figure 9-3). Crinoids and sheet-like fenestrate bryozoans, in the form of thickets, are associated with the deeper parts of the mud mounds and are indicative of well-circulated, normal-marine salinity. This facies represents a low- to moderate-energy environment. Water depths ranged from 60 to 90 feet (20-30 m).

Shoal-flank facies are associated with both crinoid bank/shoal and Waulsortian-type buildup facies (figure 9-3). This facies represents a moderate-energy environment, again with well-circulated, normal-marine salinity water in a subtidal setting. Water depths ranged from 60 to 90 feet (20-30 m).

Restricted-marine facies are represented by "hard" peloid and oolitic shoals that developed as a result of regularly agitated, shallow-marine processes on the shelf (figure 9-3). Like crinoidal banks and Waulsortian-type buildups, hard peloid and oolitic shoals are common throughout Leadville deposition, especially on paleotopographic highs. This facies represents a moderate- to high-energy environment, with moderately well-circulated water in an intertidal setting. The water probably had slightly elevated salinity compared to the other facies. Sediment deposition and modification probably occurred in water depths ranging from near zero to 20 feet (6 m).

Middle-shelf facies covered extensive areas across the shallow shelf. This facies represents a low-energy, often restricted-marine environment (figure 9-3). Mud and some sand were deposited in a subtidal (burrowed), inter-buildup/shoal setting. Water depths ranged from 60 to 90 feet (20-30 m).

Stratigraphy and Thickness

The Leadville Limestone is typically 300 to 600 feet (100-200 m) thick in the play area (Hintze, 1993). However, the Leadville thins from more than 700 feet (230 m) in the northwest corner of the Paradox Basin to less than 200 feet (70 m) in the southeast corner (Morgan, 1993a) (figure 9-2). Thinning is a result of both depositional onlap onto the Mississippian cratonic shelf and erosion. The Leadville is divided into two informal members, a dolomitic lower member and a limestone and dolomite upper member, separated by an intraformational disconformity (Fouret, 1982, 1996). Each unit has a subtle but distinct characteristic geophysical log response (figure 9-5).

The Leadville Limestone is overlain by the Pennsylvanian Molas Formation and underlain by the Devonian Ouray Limestone (figures 9-1 and 9-5). Average depth to the Leadville in Paradox Basin fields is 8760 feet (2920 m).

Lithology

The depositional fabrics of open-marine crinoidal banks and shoals include grainstone and packstone (figure 9-6A). Rocks representing crinoidal banks and shoals typically contain the following diagnostic constituents: dominantly crinoids and rugose corals, and lesser amounts of broken fenestrate bryozoans, brachiopods, ostracods, and endothyroid forams as skeletal debris. Low to medium cross-bedding is common. Rock units having this facies constitute a significant reservoir potential, having both effective porosity and permeability when dissolution of skeletal grains, followed by dolomitization, has occurred.

The depositional fabrics of the open-marine Waulsortian-type buildups include mud-supported boundstone, packstone, and wackestone (figure 9-6B). Rocks representing Waulsortian-type buildups typically contain the following diagnostic constituents: peloids, crinoids, bryozoans, and associated skeletal debris, and *stromatactis*. Rock units having this facies constitute a significant reservoir potential, having both effective porosity and permeability, especially after dolomitization.

The depositional fabrics of the shoal-flank facies include peloidal/skeletal packstone and wackestone (figure 9-7A). Bedding is generally absent in cores. Rocks representing this facies typically contain the following diagnostic constituents: peloids, crinoids, bryozoans, brachiopods, and associated skeletal debris, and talus, depositional breccia, and conglomerate (Fouret, 1982, 1996). Rock units having shoal-flank facies constitute a limited reservoir potential, having little effective porosity and permeability.

The depositional fabrics of the restricted-marine facies include grainstone and packstone (figure 9-7B). Rocks representing this facies typically contain the following diagnostic constituents: ooids, coated grains, and hard pelloids. Fossils are relatively rare. Rock units having restricted-marine facies constitute good reservoir potential. Remnants of visible interparticle and moldic porosity may be present in this facies. Dolomitization significantly increases the reservoir quality of this facies.

The depositional fabrics of the middle-shelf facies include wackestone and mudstone (figure 9-7C). The most common is bioturbated lime to dolomitic mudstone with sub-horizontal feeding burrows. Rocks representing this facies typically contain the following diagnostic constituents: soft pellet muds, “soft” peloids, grain aggregates, crinoids and associated skeletal debris, and fusulinids. Rock units having middle-shelf facies generally act as barriers and baffles to fluid flow, having very little effective porosity and permeability. There are few megafossils and little visible matrix porosity, with the exception of an occasional moldic pore. However, recognizing this facies is important because low-energy carbonates of the middle shelf form the substrate for the development of the higher energy crinoid banks, oolitic/hard peloid shoals, and Waulsortian-type buildups (figure 9-3). The middle-shelf facies can contain reservoir-quality rocks if dolomitized.

Fractures in the Leadville Limestone are an important reservoir component. They are associated with folding and faulting or collapse related to karst processes.

Hydrocarbon Source and Seals

Hydrocarbons in Leadville Limestone reservoirs were likely generated from source rocks in the Pennsylvanian Paradox Formation (figure 9-1). Organic-rich informal units, such as the Cane Creek, Chimney Rock, and Gothic shales, are well established source rocks for oil

produced from the Paradox Formation itself (Hite and others, 1984; Nuccio and Condon, 1996). These rocks are composed of black, sapropelic shale and shaley dolomite, deposited in quiet water under anaerobic bottom conditions (Morgan, 1993a). The average total organic carbon (TOC) content of the black shale in Cane Creek shale is 15% with some samples containing up to 28% (Grummon, 1993). The Chimney Rock shale has from 1 to 3% TOC and a mean vitrinite reflectance (R_o mean) of 1.3 to 2.5. The Gothic shale has from 1.5 to near 4% TOC and an R_o mean of 0.8 to 1.2 (Hite and others, 1984; Peterson, 1992). Other, deeper shale facies in the Paradox Formation contain as much as 13% TOC (Hite and others, 1984). Peterson (1992) calculates a cumulative thickness of more than a 1000 feet (330 m) of organic-rich rocks in the Paradox.

Hydrocarbon generation occurred during maximum burial in the Late Cretaceous and early Tertiary. Hydrocarbons were then expelled and subsequently migrated, primarily along fault planes, into carrier beds or structures where the Leadville Limestone was juxtaposed directly against Pennsylvanian source rocks. Fracture systems developed along fault systems may have provided secondary migration routes. Oil generated from non-Pennsylvanian source rocks require long-distance migration.

The seals for the Leadville producing zones are the overlying clastic beds of the Pennsylvanian Molas Formation (figure 9-1). Hydrocarbons in the Leadville are further sealed by evaporite (salt and anhydrite) beds within the overlying Pennsylvanian Paradox Formation.

Structure and Trapping Mechanisms

Most oil and gas produced from the Leadville Limestone is found in basement-involved, northwest-trending structural traps with closure on both anticlines and faults (figure 2-20). Lisbon, Big Indian, Little Valley, and Lisbon Southeast fields (figure 9-2) are found on sharply folded anticlines that close against the Lisbon fault zone. Salt Wash and Big Flat fields (figure 9-2), northwest of the Lisbon area, are found on unfaulted, east-west- and north-south-trending anticlines, respectively. The unfaulted structures probably developed from movement on deep, basement-involved faults that do not rise to the level of the Leadville. These and other faults affecting the Leadville probably reflect the reactivation of pre-existing, Precambrian-age faults during the Laramide orogeny or later. As examples of both types of structural traps, Big Flat and Lisbon fields are briefly described below.

Big Flat Field

Big Flat field, Grand County, Utah, was the first Mississippian discovery in the Paradox Basin (figure 9-2). The trap is a doubly plunging anticline with 276 feet (84 m) of structural closure (figure 9-8) that produced from Leadville limestone and dolomite (Smith, 1978b). The net reservoir thickness is 30 feet (10 m), which extends over a 480-acre (190-ha) area. The field now produces oil from horizontal wells in the Cane Creek shale of the Paradox Formation, on a separate structure north of the original, abandoned Leadville feature.

Lisbon Field

Lisbon field, San Juan County, Utah (figure 9-2) accounts for most of the Leadville oil production in the Paradox Basin. The trap is an elongate, asymmetric, northwest-trending

anticline, with nearly 2000 feet (600 m) of structural closure and bounded on the northeast flank by a major, basement-involved normal fault with over 2500 feet (760 m) of displacement (Smith and Prather, 1981) (figures 9-9 and 9-10). Several minor, northeast-trending normal faults dissect the Leadville reservoir into segments. The net reservoir thickness is 225 feet (69 m) over a 5120-acre (2100-ha) area (Clark, 1978; Smouse, 1993b).

Reservoir Properties

The Leadville Limestone has heterogeneous reservoir properties because of (1) depositional facies with varying porosity and permeability, (2) diagenetic effects, and (3) fracturing. Identification and correlation of depositional facies in individual Leadville reservoirs is critical to understanding their effect on production rates and paths of petroleum movement. Natural fractures also affect permeability, and control hydrocarbon production and injection fluid pathways. Leadville reservoir porosity ranges from 4 to 21% with typical porosity averaging 6 to 8% (Morgan, 1993a). Permeability is variable, generally ranging from 3 to 10 mD. At Lisbon field, San Juan County, Utah (figure 9-2), the permeability ranges from less than 1 to 1100 mD, averaging 22 mD (Smouse, 1993b).

The early diagenetic history of the Leadville sediments, including some dolomitization (finely crystalline) and leaching of skeletal grains (figure 9-11A), resulted in low-porosity and/or low-permeablility rocks. Most of the porosity and permeability associated with hydrocarbon production at Lisbon field, for example, was developed during later, deep subsurface dolomitization (coarsely crystalline replacement and saddle [hydrothermal?] dolomite) and dissolution (figures 9-4 and 9-11B). Predating or concomitant with saddle dolomite formation are pervasive leaching episodes that cross-cut the carbonate host rocks with dissolution resulting in late vugs as well as extensive microporosity. Pyrobitumen appears to coat most intercrystalline dolomite as well as dissolution pores associated with the late dolomite. Extensive solution-enlarged fractures and autobreccias are also common (figure 9-12A). Sediment-filled cavities are relatively common throughout the upper third of the Leadville in Lisbon field (figure 9-12B). These cavities or cracks were related to karstification of the exposed Leadville (figure 9-4). Infilling of the cavities by detrital carbonate and siliciclastic sediments occurred before the deposition of the Pennsylvanian Molas Formation.

Leadville net-pay thickness is also variable, depending on diagenesis and fracturing, and ranges from 19 to 225 feet (6-75 m). The average Leadville reservoir temperature is 134ºF 57ºC). Water saturations range from 25 to 50%, salinities range from 1830 to 20,000 parts per million, and resistivities (R_w) range from 0.059 to 0.103 ohm-m at 68ºF (20ºC). Initial reservoir pressures average about 3022 pounds per square inch (20,840 kPa). The reservoir drive mechanisms include gas expansion, water drive, and gravity drainage.

Reservoir data for individual fields in the Mississippian Leadville Limestone Paradox Basin play are summarized in table 9-1. For details see Stowe (1972), Cargile (1978), Clark (1978), Latch (1978a, 1978b), Norton (1978a), Smith (1978b), Parker (1981), Morgan (1993a), Smouse (1993b, 1993c), Gwynn (1995), Utah Division of Oil, Gas and Mining (2007), and Colorado Oil & Gas Conservation Commission (2007).

Oil and Gas Characteristics

In major reservoirs, the produced Leadville oil and condensate are rich, volatile crudes. The API gravity of the oil ranges from 41º to 54º; the gas-oil ratio ranges between 50 and 3150 cubic feet/bbl. The API gravity of the condensate ranges from 60º to 66º. Oil colors vary from brownish green to yellow/amber to red, and condensate can be light green to yellow to red. The viscosity of the crude oil ranges from 32 to 55 sus at 100ºF (38ºC); the viscosity of the condensate is less than 32 sus at 100ºF (38ºC). The pour point of the crude oil ranges from 40 to 85ºF (4-29ºC). The average weight percent sulfur and nitrogen of produced Leadville hydrocarbon liquids are 0.13 and 0.005, respectively (Stowe, 1972).

Leadville reservoirs produce associated gas that is variable in composition. Associated gas produced at Lisbon field contains 40% methane, 9% ethane, 7% propane, 2% butane, 1% pentane, 0.5% hexane and higher fractions, 13% nitrogen, 27% carbon dioxide, and 1% helium. The gas heating value averages 892 Btu/ft^3; the specific gravity averages 1.046. Associated gas produced at Salt Wash field contains 13% methane, 3% ethane, 3% propane, 3% butane, 1% pentane, 0.5% hexane and higher fractions, 71% nitrogen, 3% carbon dioxide, and 1.5% helium. The gas heating value averages 443 Btu/ft^3; the specific gravity averages 1.005 (Moore and Sigler, 1987).

Leadville reservoirs produce nonassociated gas that is relatively uniform in composition: 64% methane, 5% ethane, 2% propane, 1% butane, 0.3% pentane, 0.4% hexane and higher fractions, 13% nitrogen, 13% carbon dioxide, and 0.7% helium. The gas heating values average 864 Btu/ft^3; the specific gravity averages 0.813 (Moore and Sigler, 1987). Gas produced from the reservoirs in the Leadville Limestone Paradox Basin play contains only a trace of hydrogen sulfide.

Production

Three fields in the Leadville Limestone Paradox Basin play have produced crude oil and associated gas. Big Flat, Lisbon, and Salt Wash fields (figure 9-2) have combined to produce nearly 53 million bbls of oil (MMBO [8.4 MMCMO]) and 785 BCF (22.2 BCM) of gas from the Leadville as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008) (table 9-1). There are currently 29 active producers and 20 abandoned Leadville producers in these three fields (table 9-1).

Three fields in the Leadville Limestone Paradox Basin play have produced condensate and nonassociated gas. Big Indian, Lisbon Southeast, and Little Valley fields (figure 3) have combined to produce 480,930 bbls of condensate (76,468 m^3) and 59.9 BCF (1.70 BCM) of gas from the Leadville as of January 1, 2008 (Utah Division of Oil, Gas and Mining, 2008; Colorado Oil & Gas Conservation Commission, verbal communication, April 2005) (table 9-1). There are currently seven active producers and three abandoned producers in these three fields (table 9-1).

In 2007, the monthly production from the Leadville Limestone averaged 3022 bbls of oil (and condensate) (481 m^3) and 1.17 BCF (0.03 BCM) of gas (Utah Division of Oil, Gas and Mining, 2008; Colorado Oil & Gas Conservation Commission, 2008). Production peaked in the mid to late 1960s, and has generally declined since then.

Exploration Potential and Trends

The buried fault block has been the most common target for exploration of hydrocarbons in the Leadville Limestone because it has a proven history of success and fault blocks can be identified on gravity, aeromagnetic, and seismic geophysical data. Therefore future exploration will likely continue to focus on fault-related anticlines along existing producing trends. However, regional facies mapping (from studying cores and geophysical well logs) show that stratigraphic oil accumulations may exist to the west and southwest of the fold and fault belt. Traps may be formed by porous Waulsortian mounds, or other carbonate buildups, where porosity is further enhanced by early dolomitzation. Additional traps may also be developed in the regolith deposits, that is collapse breccia associated with karstification of the exposed Leadville during Late Mississippian time. Diagenetic traps formed from late, possibly hydrothermal dolomite may be present especially along major fault trends. Surface geochemical surveys (Seneshen and others, 2009) and high-resolution 3D seismic are required to improve the ability to identify these subtle stratigraphic and diagenetic traps.

Eby and others (2008) identified potential oil-prone areas for exploration in the northern Paradox Basin based on shows in drill cuttings (using low-cost epifluorescence techniques). The epifluorescence analysis of Leadville oil compared to epifluorescence in the cores and cuttings from Lisbon field created a Leadville epifluorescence standard. The standard can be used to map Leadville oil migration patterns (no hydrocarbons, hydrocarbons passed through, hydrocarbons present but not mobile, hydrocarbons mobile). As expected, productive wells (fields) are distinguished by generally higher epifluorescence ratings. However, a regional southeast-northwest trend of relatively high epifluorescence parallels the southwestern part of the Paradox fold and fault belt while the northeastern part shows a regional trend of low epifluorescence. This implies that hydrocarbon migration and dolomitization were associated with regional northwest-trending faults and fracture zones, which created potential oil-prone areas along the southwest trend.

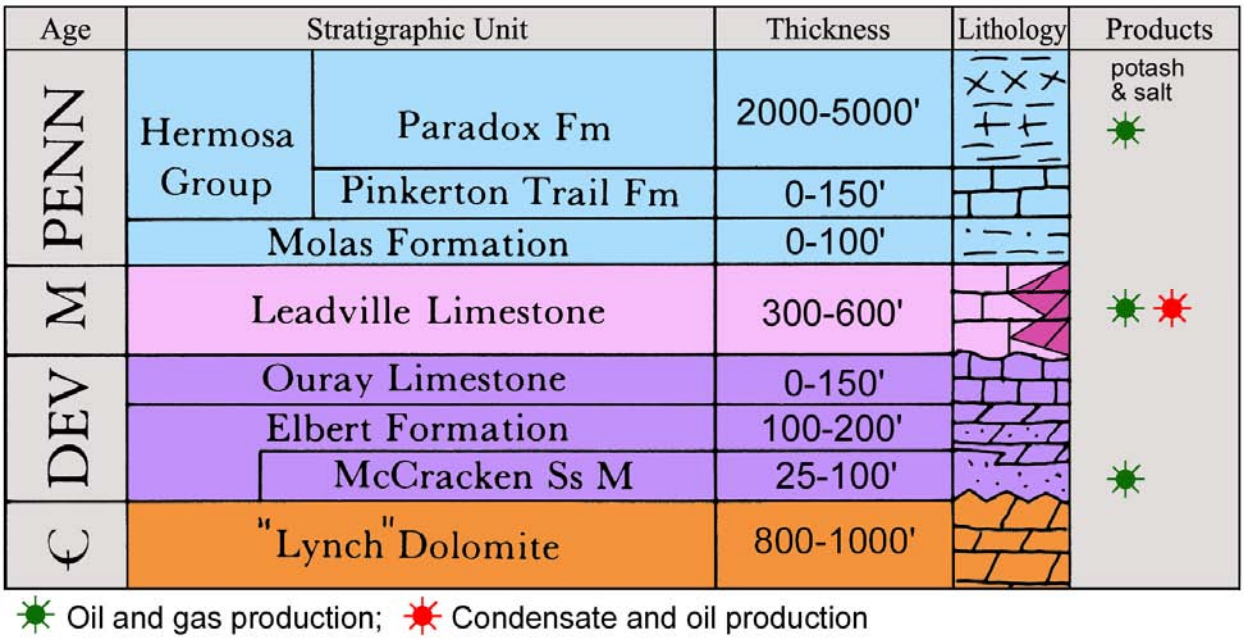


Figure 9-1. Stratigraphic column of a portion of the Paleozoic section determined from subsurface well data in the Paradox fold and fault belt, Grand and San Juan Counties, Utah (modified from Hintze, 1993).

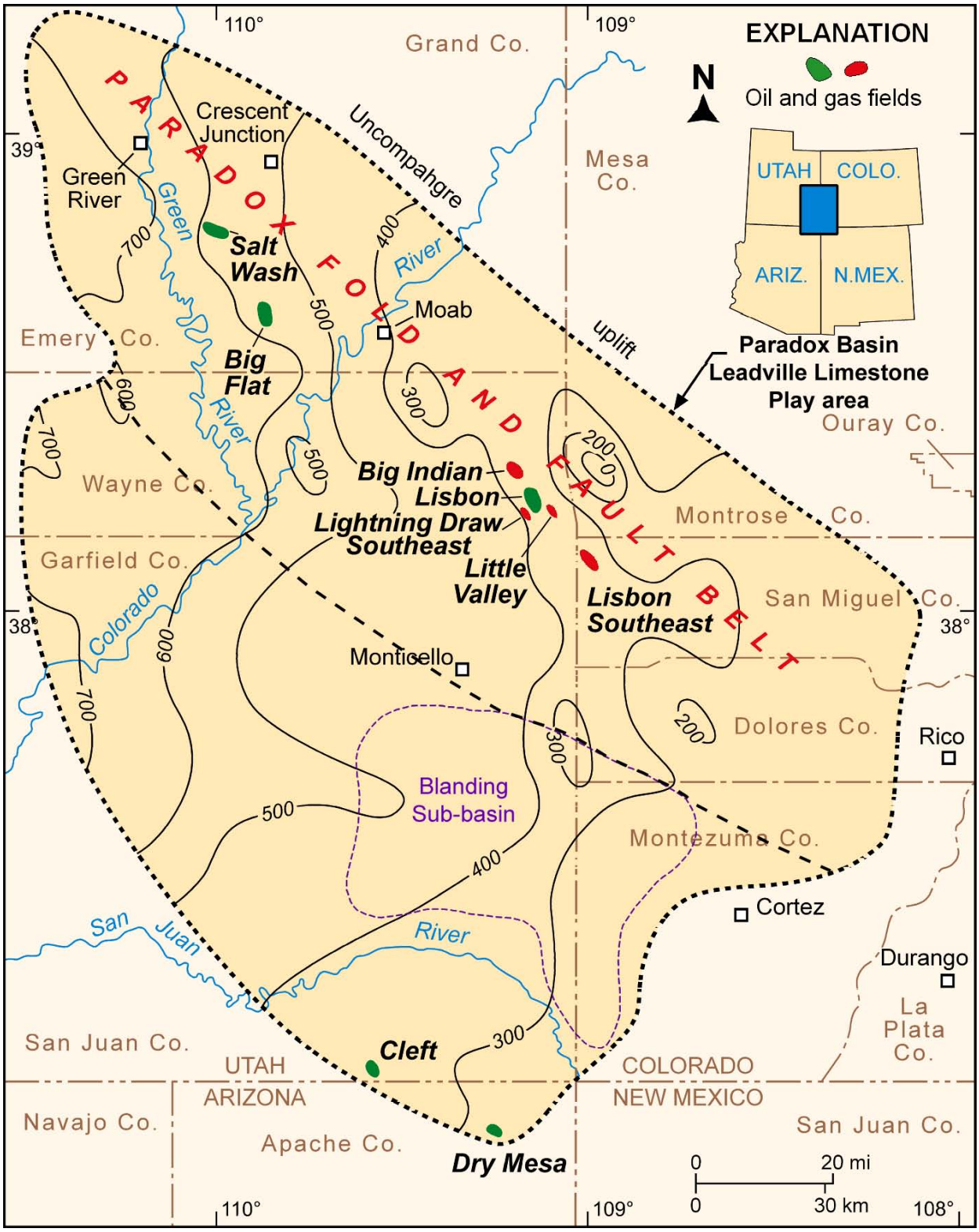


Figure 9-2. Location of fields that produce from the Mississippian Leadville Limestone, Arizona, Utah and Colorado. Thickness of the Leadville is shown; contour interval is 100 feet (modified from Parker and Roberts, 1963). The Leadville Limestone Paradox Basin play area is dotted. Modified from Morgan (1993a).

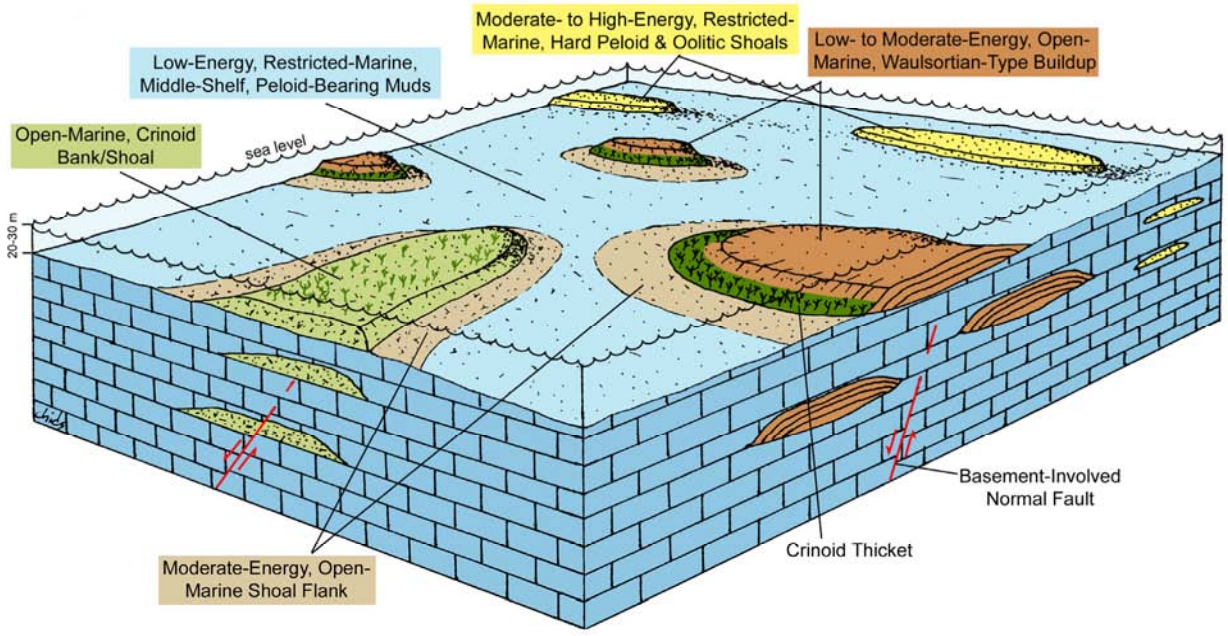


Figure 9-3. Block diagram displaying major depositional facies, as determined from core, for the Mississippian Leadville Limestone.

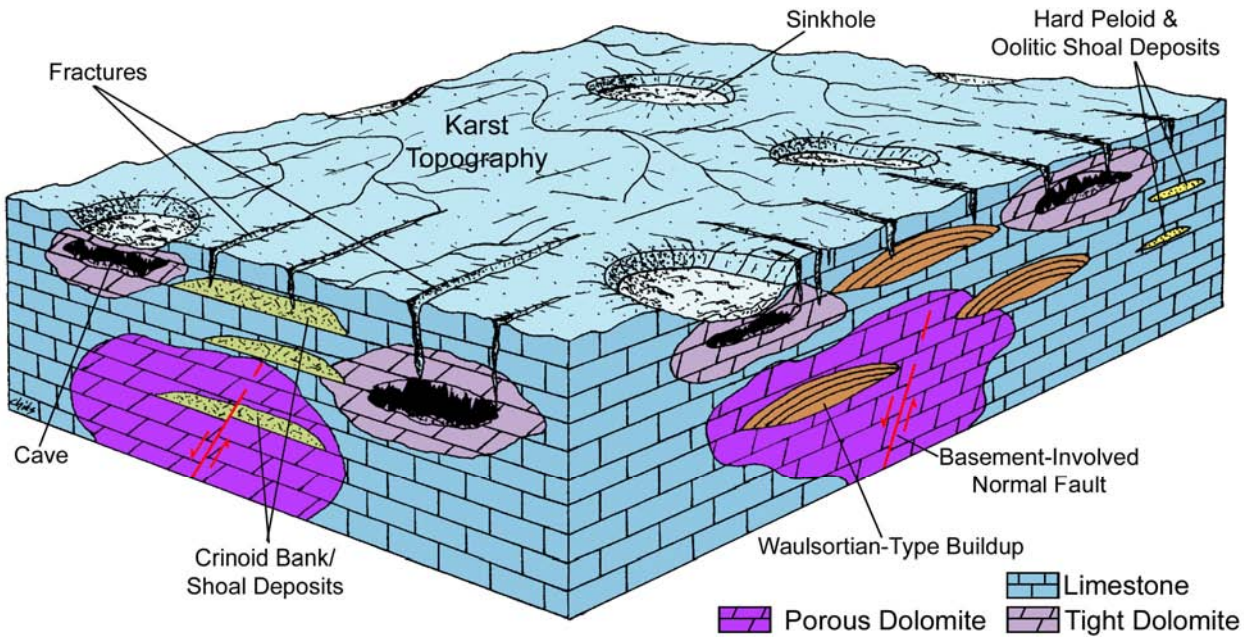


Figure 9-4. Block diagram displaying post-Leadville karst and fracture overprint.

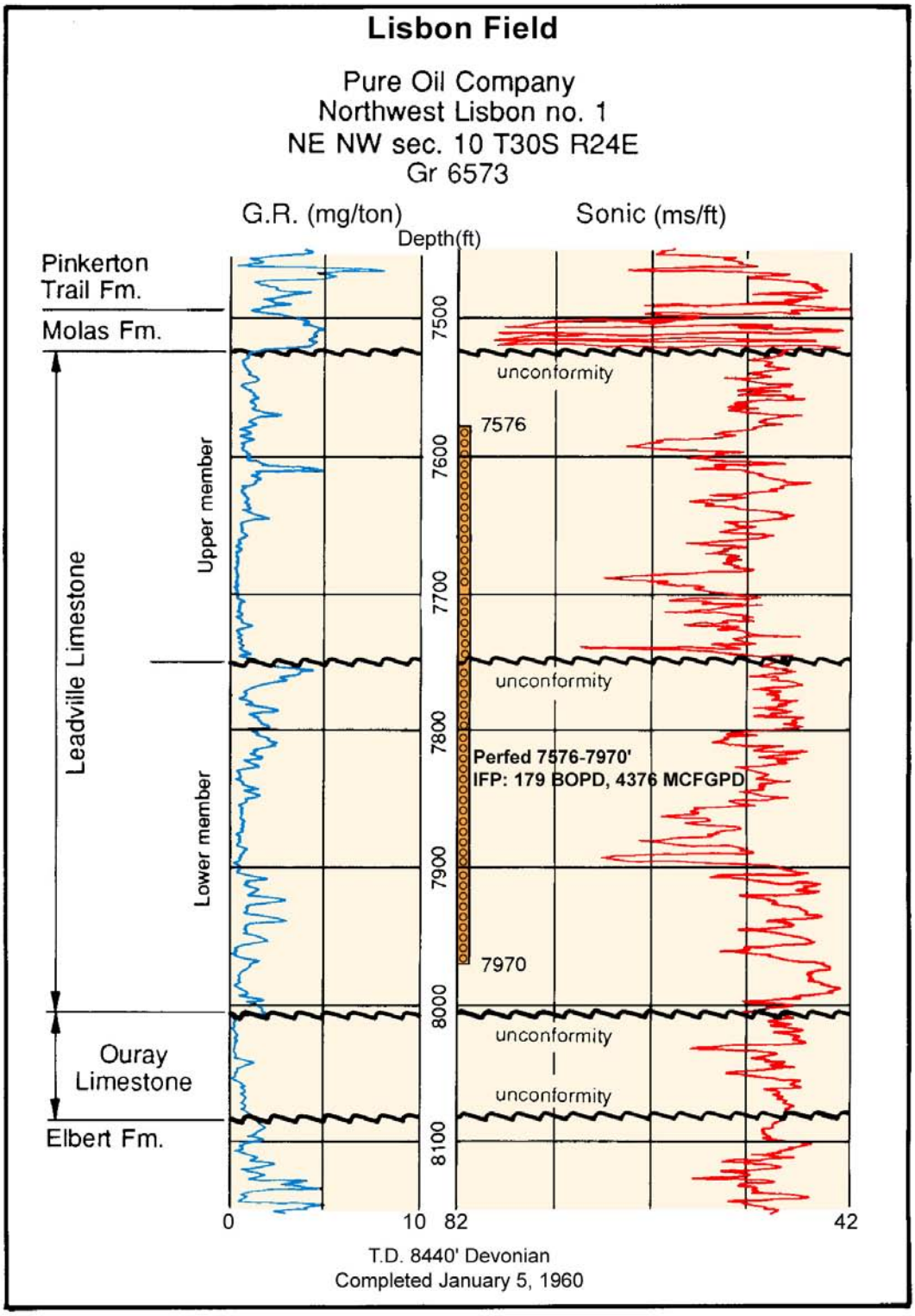


Figure 9-5. Typical gamma ray-sonic log of the Leadville Limestone, Lisbon field discovery well, San Juan County, Utah. Producing (perforated) interval between depths of 7576 and 7970 feet. See figure 9-2 for location of Lisbon field.

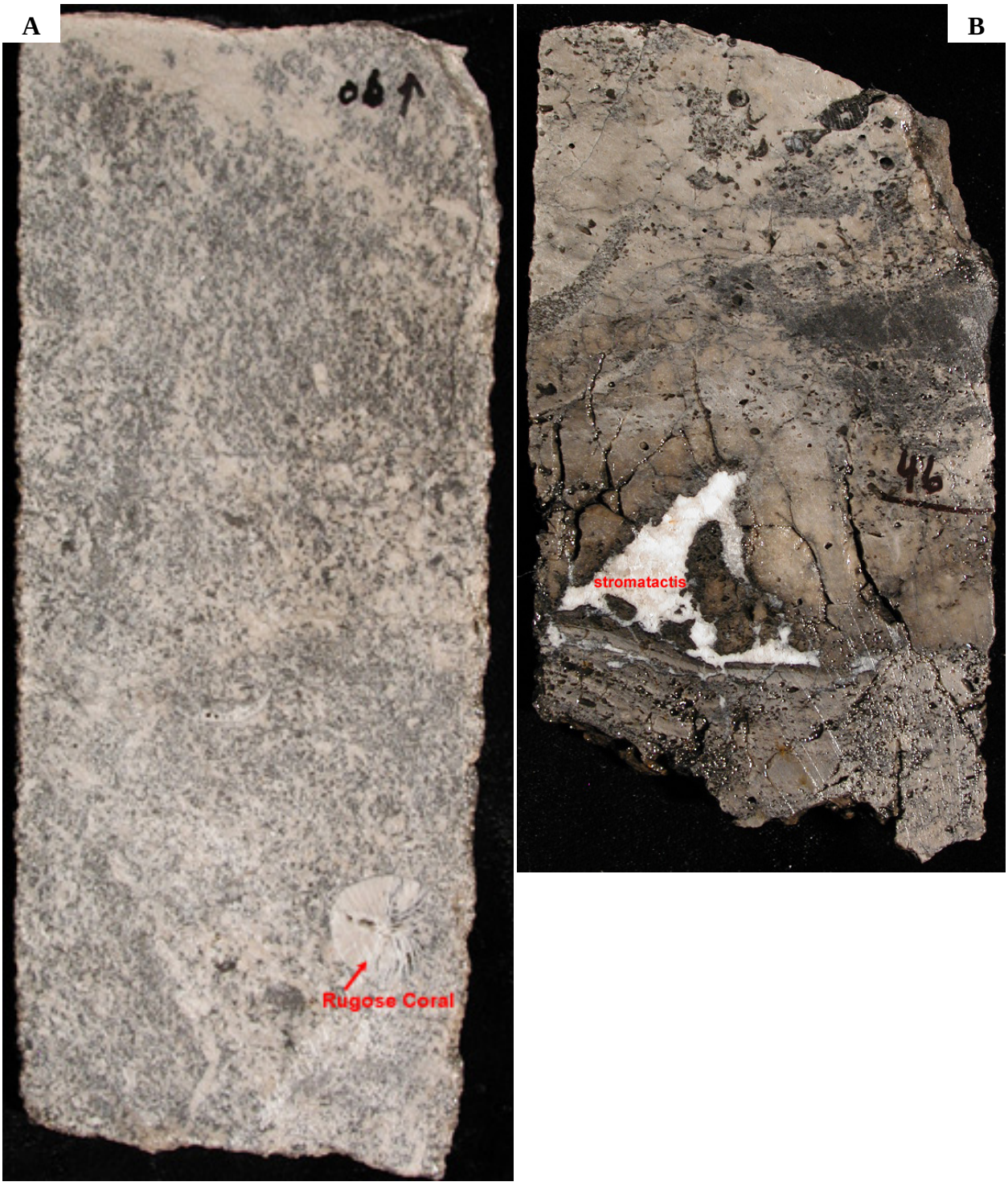


Figure 9-6. Typical Leadville Limestone depositional fabrics from Lisbon field, San Juan County, Utah. A - Crinoidal/skeletal grainstone/packstones representing high-energy, open-marine shoal facies; slabbed core from 8506.5 feet, Lisbon No. B-816 well. B - Peloidal/ skeletal packstone/wackestones representing moderate- to low-energy, open-marine, Waulsortian-type buildup facies; slabbed core from 8646 feet, Lisbon No. B-816 well.



Figure 9-7. Typical Leadville Limestone depositional fabrics from Lisbon field, San Juan County, Utah. A - Peloidal/skeletal packstone/wackestone representing moderate-energy, open-marine, shoal-flank facies; slabbed core from 8521 feet, Lisbon No. B-816 well. B - Peloidal grainstone/packstone representing moderate-energy, restricted-marine, "hard" peloid shoal facies; slabbed core from 8463 feet, Lisbon No. B-816 well. C - Skeletal/"soft" peloidal wackestone/mudstone representing low-energy, restricted-marine, middle-shelf facies; slabbed core from 8549 feet, Lisbon No. B-816 well.

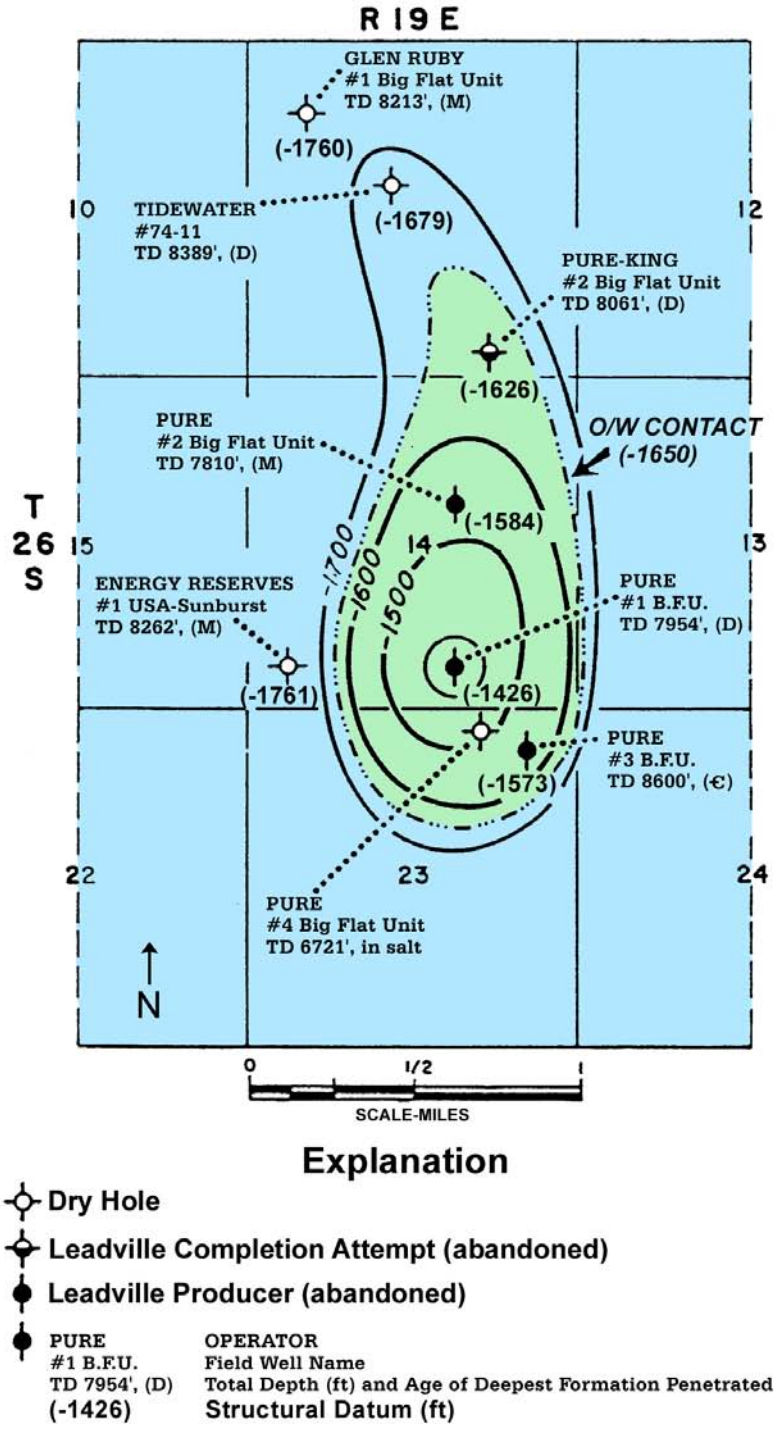


Figure 9-8. Top of structure of the Leadville Limestone, Big Flat field, Grand County, Utah. Contour interval = 100 feet, datum = mean sea level. Modified from Smith (1978a).

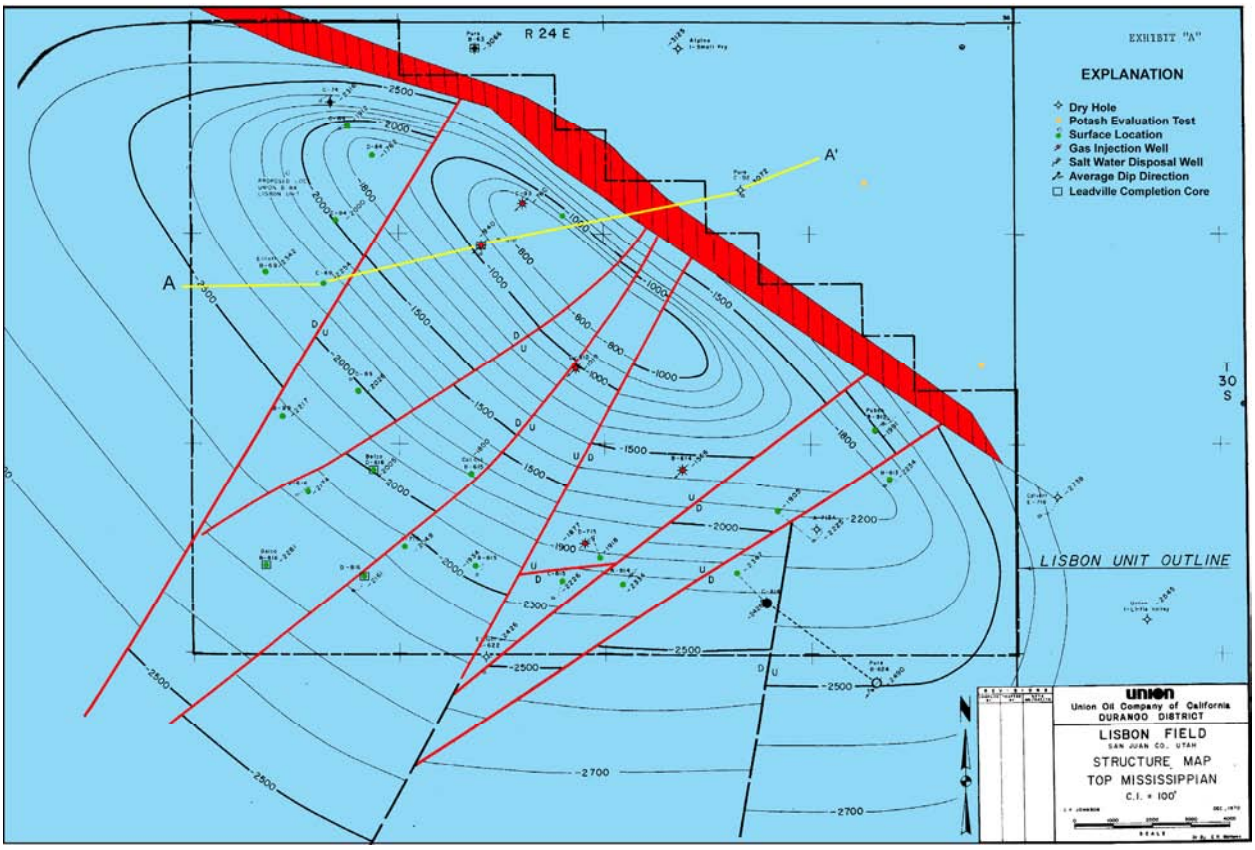


Figure 9-9. Top of structure of the Leadville Limestone, Lisbon field, San Juan County, Utah. Contour interval = 500 feet, datum = mean sea level. The field is bounded on its northeast flank by a major, basement-involved normal fault (in red) with greater than 2500 feet of displacement. Note the multiple, northeast-trending faults that divide the Leadville reservoir into several segments. Some of the best producing wells are located close to these faults. Modified from C.F. Johnson, Union Oil Company of California files (1970); courtesy of Tom Brown, Inc. Cross section A-A' shown on figure 9-10.

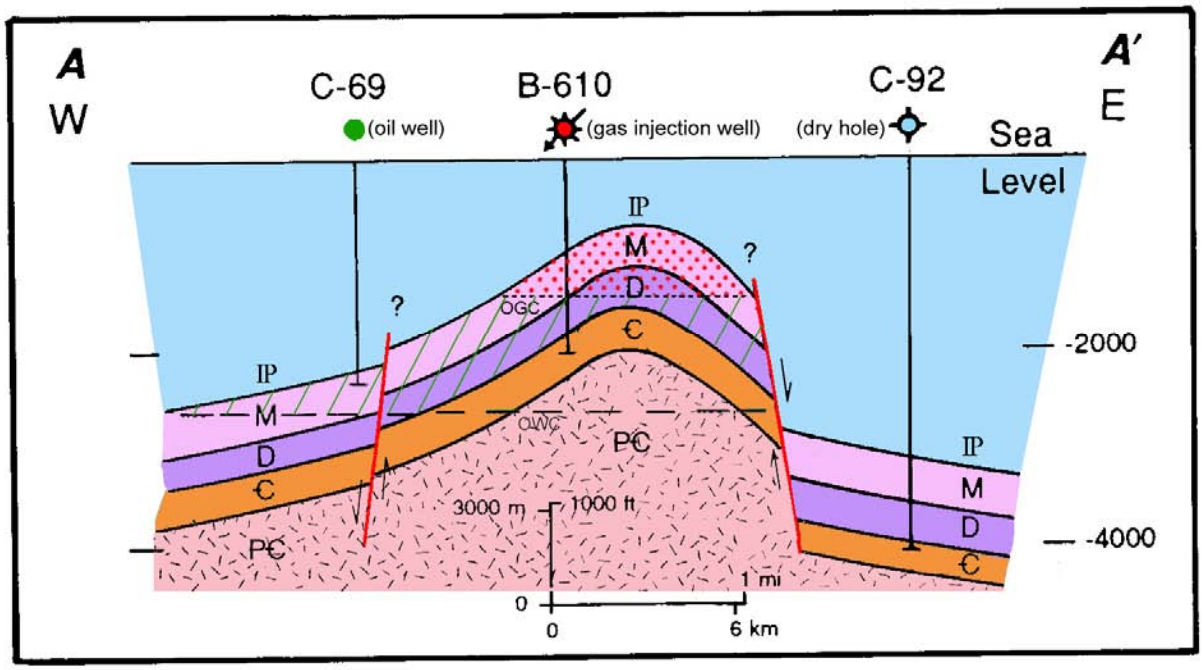


Figure 9-10. Schematic east-west cross section through Lisbon field. Line of section shown on figure 9-9. Note the juxtaposition of the Mississippian (M) section against the Pennsylvanian (IP) section which includes evaporites (salt) and organic-rich shale. OGC = oil-gas contact, OWC = oil-water contact. Modified from Clark, 1978.

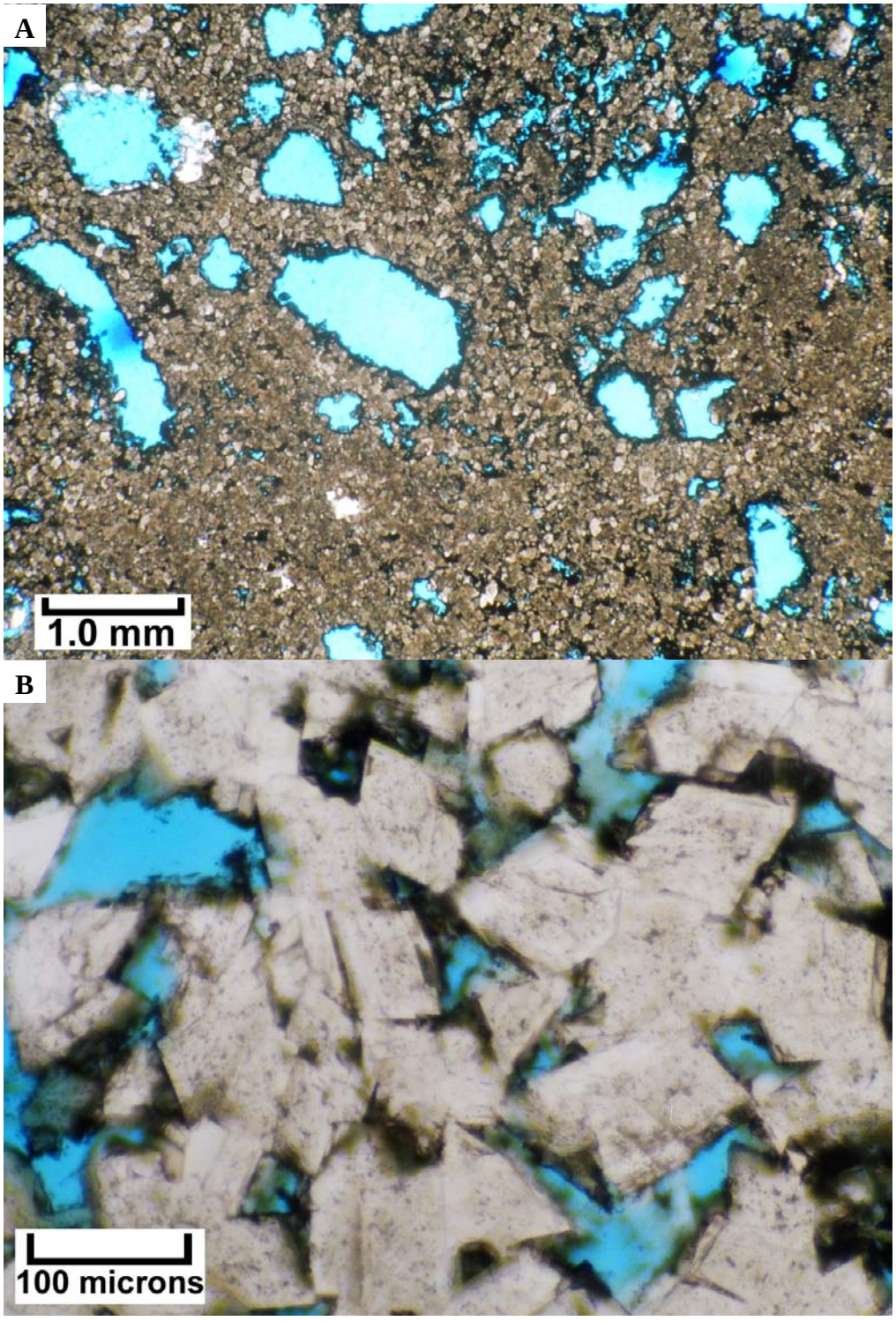


Figure 9-11. Leadville Limestone diagenetic characteristics from Lisbon field, San Juan County, Utah. A - Representative photomicrograph (plane light) of the tight, finely crystalline dolomite with isolated grain molds. Most of this fabric-selective dolomite formed early in the diagenetic history of the skeletal/peloid sediment. B - Representative photomicrograph (plane light) of the coarser, replacement dolomite (both euhedral rhombs and occasional "saddle" overgrowths). The black (opaque) areas are the result of pyrobitumen films. From Lisbon No. D-816 well, 8433 feet: porosity = 2%, permeability <0.1 mD.



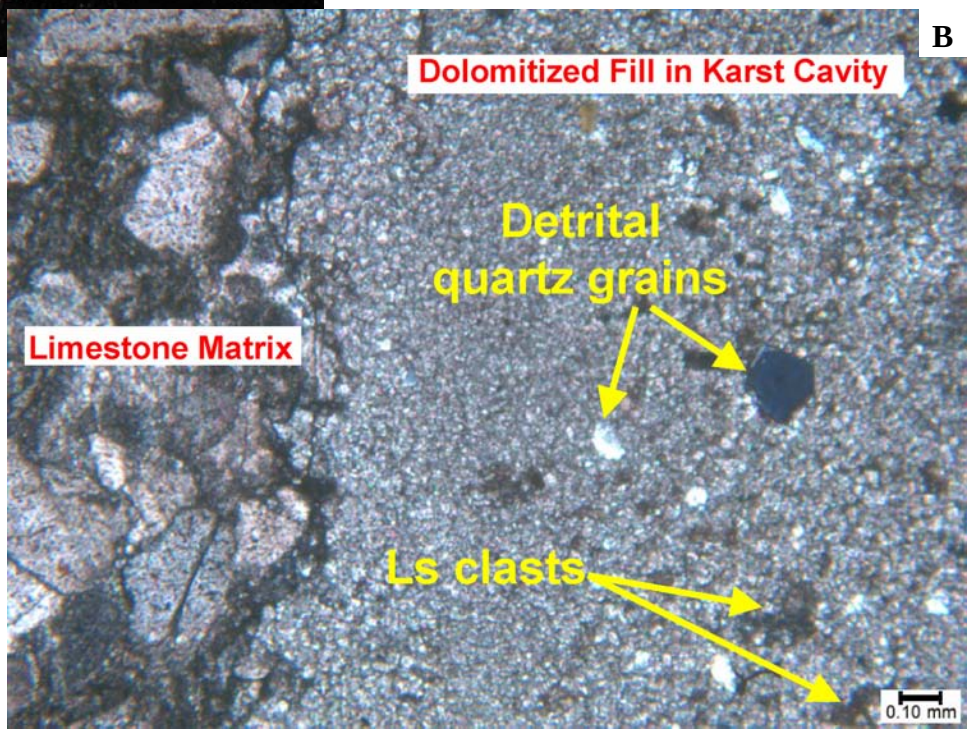


Figure 9-12. Leadville Limestone diagenetic characteristics from Lisbon field, San Juan County, Utah. A - Conventional core slab showing a dolomite "autobreccia" in which the clasts have moved very little. The black material surrounding the in-place clasts is composed of porous late dolomite coated with pyrobitumen. From Lisbon NW USA No. B-63 well, 9938.3 feet, porosity = 6.4%, permeability = 54 mD. B - Photomicrograph (cross-polarized light) showing contact between limestone matrix and the dolomitized karst cavity filling; note that the dolomitized filling is composed of very fine crystals with detrital quartz grains and small carbonate clasts. From Lisbon No. D-616 well, 8308 to 8309 feet, porosity = 1.2%, permeability = 11.1 mD.

Table 9-1. Geologic, reservoir, and production data for fields in the Mississippian Leadville Limestone Paradox Basin play. Data compiled from Stowe (1972), Cargile (1978), Clark (1978), Latch (1978a, 1978b), Norton (1978a), Smith (1978a), Parker (1981), Morgan (1993a), Smouse (1993b, 1993c), Utah Division of Oil, Gas and Mining (2008), and Colorado Oil & Gas Conservation Commission (2008).

State	County	Field	Discovery Date	Active Producers	Abandoned Producers	Acres	Spacing (acres)	Pay (feet)	Porosity (%)	Permeability (mD)	Temp. (°F)	Initial Reservoir Pressure (psi)	Average Monthly Production		Cumulative Production	
													Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (BCF)
Colorado	San Miguel	Lisbon Southeast	1960	5	1	800	640	50	8	10	NA	2340	313	50,295	164,922	16.2
Utah	San Juan	Big Flat	1957	0	3	480	80	30	9	variable	125	2450	0	0	83,469	0.05
Utah	San Juan	Big Indian	1961	1	0	640	640	72	6	3-10	148	3240	0	0	178,160	26.4
Utah	San Juan	Lisbon	1960	22	13	5120	320	225	6	22	127	2982	2917	1,114,919*	51,045,833	773.6*
Utah	San Juan	Little Valley	1961	0	3	660	160	100	6	6-10	127	3043	0	0	137,848	17.3
Utah	Grand	Salt Wash	1961	7	4	920	160	19	8	NA	143	4075	793	42	1,563,865	11.7

NA = Not available
*Includes cycled gas

CHAPTER 10
PENNSYLVANIAN PARADOX FORMATION PARADOX BASIN PLAY

Thomas C. Chidsey, Jr., and Craig D. Morgan,
Utah Geological Survey

Introduction

The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play (figure 10-1). The Paradox has produced over 500 million barrels of oil (BO [80 million m^3]) and 650 billion cubic feet of gas (BCFG [18 billion m^3]); however, much of the gas included in the production figures is cycled gas, including carbon dioxide, for pressure maintenance (Utah Division of Oil, Gas and Mining, 2008; Colorado Oil & Gas Conservation Commission, 2008). Since the early 1920s, the Paradox Basin has been a site for oil exploration drilling. The Cane Creek anticline in the Paradox fold and fault belt was one of the most obvious structural drilling targets and first tested oil in 1924 (figure 1-9). However, the Cane Creek field only produced 1887 BO (300 m^3) and 25 million cubic feet of gas (MMCFG [0.7 MMCMG]), primarily from the Cane Creek shale (Stowe, 1972). The first commercial production from the Paradox Formation did not begin until the 1950s. Greater Aneth field, Utah's largest oil producer, was discovered in 1956, and it has produced over 440 million BO (70 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The remaining 60 million BO of production is from nearly 100 small fields in the basin. Using a minimum production cutoff of 500,000 BO (80,000 m^3) there are currently 27 significant Paradox fields in Utah, eight in Colorado, and one in Arizona. Geologic data for 32 individual fields in the play are summarized in table 10-1.

The play outline represents the maximum extent of petroleum potential in the geographical area as defined by producing reservoirs, hydrocarbon shows, and untested hypotheses. The attractiveness of the Paradox Formation play (and other Paradox Basin oil and gas plays) to the petroleum industry depends on the likelihood of successful development, reserve potential, pipeline access, drilling costs, oil and gas prices, and environmental concerns. When evaluating these criteria, certain aspects of the Paradox Formation play may meet the exploration guidelines of major oil companies while other aspects meet the development guidelines of small, independent companies. Prospective drilling targets in the Paradox Formation play are delineated using high-quality two-dimensional (2-D) and three-dimensional (3-D) seismic data, 2-D and 3-D forward modeling/visualization tools, well control, dipmeter information, facies mapping, and detailed analyses of the diagenetic history.

The three main producing zones of the Paradox Formation are informally named the Cane Creek shale, Desert Creek zone, and Ismay zone (figure 10-2). Fractured shale beds in the Cane Creek shale are oil productive in the Paradox Basin fold and fault belt. The Ismay mainly produces oil from fields along a trend that crosses the southern Blanding sub-basin. The Desert Creek produces oil in fields along a trend that crosses the central Blanding sub-basin and Aneth platform. Both the Ismay and Desert Creek buildups generally trend northwest-southeast. Various facies changes and extensive diagenesis have created complex reservoir heterogeneity within the diverse Desert Creek and Ismay zones.

The Paradox Formation oil play area includes nearly the entire Paradox Basin (figure 10-1); the formation produces only gas in the southeastern part of the basin in Colorado. The Paradox Formation play is divided into four subplays (figures 10-3 and 10-4): (1) fractured shale,

(2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone.

Depositional Environments

In Pennsylvanian time, the Paradox Basin was rapidly subsiding along its northeast margin, but with a shallow-water carbonate shelf on the south and southwest margins of the basin that locally contained algal-mound buildups. These carbonate buildups, and the material shed from their flanks, formed petroleum traps where reservoir-quality porosity and permeability have developed. The substrates for these buildups were often black, organic-rich marine muds.

During the Pennsylvanian, the Paradox Basin had subtropical, dry climatic conditions and was located along the trade-wind belt, 10º to 20º north of the paleo-equator. Prevailing winds were from present-day north (Peterson and Hite, 1969; Heckel, 1977; Parrish, 1982). Open-marine waters flowed across a shallow cratonic shelf into the basin during transgressive periods. There are four postulated normal marine access ways into the Paradox Basin. The Cabezon accessway, which was located to the southeast, is generally accepted as the most likely normal marine-water conduit to maintain circulation on the shallow shelf (Fetzner, 1960; Ohlen and McIntyre, 1965; Hite, 1970). Periodic decreased circulation in the basin resulted in deposition of thick salts (halite with occasionally thinner beds of potash and magnesium salts) and anhydrite. The deeper interior of the basin to the north and northeast is composed almost entirely of salt deposits and is referred to as the evaporite salt basin (figure 10-5).

Cyclicity in Paradox Basin deposition was primarily controlled by glacio-eustatic fluctuations. The shape of the Pennsylvanian sea-level curve reflects rapid marine transgressions (rapid melting of ice caps) and slow, interrupted regression (slow ice cap buildup) (Imbrie and Imbrie, 1980; Denton and Hughes, 1983; Heckel, 1986). Irregular patterns within the transgressive-regressive cycles are thought to be a response to interference of orbital parameters (Imbrie and Imbrie, 1980). These sea-level cycles were also influenced by (1) regional tectonic activity and basin subsidence (Baars, 1966; Baars and Stevenson, 1982), (2) proximity to basin margin and evaporites (Hite, 1960; Hite and Buckner, 1981), (3) climatic variation and episodic blockage of open marine-water conduits, and (4) fluctuations in water depth and water energy (Peterson and Ohlen, 1963; Peterson, 1966; Hite and Buckner, 1981; Heckel, 1983).

Fractured Shale Subplay

Shale generally represents an open-marine, basinal environment in relatively deep water (90 to 120 feet [30-40 m]) and euxinic conditions. Deposition included (1) black to dark gray, non-calcareous, non-fossiliferous mud and silty mud, (2) spiculitic lime mud, and (3) pelagic lime mud with microfossils. This deposition took place below wave base under normal-marine salinities and low-energy conditions.

Blanding Sub-Basin Ismay and Desert Creek Zones Subplays

Ismay and Desert Creek zone depositional environments that trend across the Blanding sub-basin are shown schematically on figure 10-6. Reservoirs within the Utah portion of the upper Ismay zone of the Paradox Formation are dominantly limestones composed of small, phylloid-algal buildups; locally variable, inner-shelf, skeletal calcarenites; and rarely, open-

marine, bryozoan mounds (figure 10-6A). The Desert Creek zone is dominantly dolomite, comprising regional, nearshore, shoreline trends with highly aligned, linear facies tracts (figure 10-6B).

The controls on the sedimentation of each depositional environment were water depth, salinity, prevailing wave energy, and paleostructural position. In the Ismay zone, the following depositional environments are recognized: open-marine shelf; organic (carbonate) buildups and calcarenites at the platform edge; middle shelf or open platform interior; and restricted inner shelf or platform interior. In the Desert Creek zone, the following depositional environments are recognized: basinal; calcarenites (carbonate islands) at the platform edge; middle shelf or open platform interior; restricted inner shelf or platform interior; platform interior salinas (evaporites); and shoreline and terrestrial.

The basinal environment represents deep water (90 to 120 feet [30-40 m]) and euxinic conditions. Deposition included (1) black to dark gray, non-calcareous, non-fossiliferous mud and silty mud, (2) spiculitic lime mud, (3) pelagic lime mud with microfossils and occasional thin-shelled bivalves such as *Halobia*, and (4) thick, deep-water siliciclastic sand. The open-marine deposition was below wave base under normal-marine salinity and low-energy conditions.

The middle shelf or open platform interior represents a well-circulated, low- to moderate-energy, normal salinity, shallow-water (between 0 and 90 feet [0-30 m]) environment. Lithofacies from this environment form the dominant producing reservoirs in the Ismay and Desert Creek zones that trend across the Blanding sub-basin. Benthic forams, bivalve molluscs, and codiacean green algae (*Ivanovia* and *Kansasphyllum*) are common. Bryozoan mounds developed in the relatively quiet, deeper water of the middle shelf. Echinoderms are rare and open-marine cephalopods are generally absent. The principal buildup process, phylloid-algal growth, occurred during sea-level highstands. Paleotopography from Mississippian-aged normal faulting (reactivation of Precambrian faults [Baars, 1966; Baars and Stevenson, 1982]) produced the best marine conditions for initial algal growth.

Calcarenites are recognized in both the Desert Creek and Ismay zones and represent moderate- to high-energy, regularly agitated, marine environments where shoals and/or islands developed. Sediment deposition and modification probably occurred from 5 feet (1.5 m) above sea level to 45 feet (14 m) below sea level. These platform-edge deposits include (1) oolitic and coated grain sands, (2) crinoid, foram, algal, and fusulinid sands, (3) small, benthic foram and hard peloid sands representing stabilized peloid grain flats, and (4) shoreline carbonate islands of shell hash.

The restricted inner shelf or platform interior represents shallow water (0 to 45 feet [0-14 m]), and generally low-energy and poor circulation conditions. Fauna are limited mainly to stromatolitic algae, gastropods, certain benthic forams, and ostracods. Deposits included (1) bioclastic lagoonal to bay lime mud, (2) tidal-flat muds often with early dolomite, and (3) shoreline carbonate islands with birdseye fenestrae, stromatolites, cryptoalgal laminations, and dolomitic crusts. Platform-interior evaporites, usually anhydrite, were deposited in salinity-restricted areas.

Shoreline and terrestrial siliciclastic deposits represent beach, fluvial, and flood-plain environments. These siliciclastic deposits include argillaceous to dolomitic silt with rip-up clasts, scour surfaces, or mudcracks.

Within these depositional environments, several major Ismay and Desert Creek lithofacies are recognized and mapped across the Blanding sub-basin (figures 10-7 through 10-

9). Mapping of these lithofacies delineates prospective reservoir trends containing porous and productive buildups. Ismay lithofacies include open marine, middle shelf, inner shelf/tidal flat, bryozoan mound, phylloid-algal mound, quartz sand dune, and anhydritic salina. Desert Creek lithofacies include open marine, middle shelf, proto-mound/collapse breccia, and phylloid-algal mound.

Open-marine lithofacies dominates the lower Desert Creek zone in the Blanding sub-basin where there is very little hydrocarbon potential (figure 10-9). However, this lithofacies developed in different areas for both the upper part (northeastern and southern regions [figure 10-7]) and lower part (western to north-central regions [figure 10-8]) of the upper Ismay zone. Middle-shelf lithofacies of the upper Ismay zone covers extensive areas and surround important intra-shelf basins described later. Bryozoan mounds, quartz sand dunes, proto-mounds and some phylloid-algal mounds, and inner shelf/tidal flats developed on the low-energy carbonates of the middle-shelf environment (figures 10-7 through 10-9).

Inner shelf/tidal flat lithofacies represent relatively small areas in geographical extent, especially in the upper part of the upper Ismay zone. However, recognizing this facies is important because inner shelf/tidal flats often form the substrate for phylloid-algal mound development. Proto-mound/collapse breccia lithofacies is found in the Desert Creek zone and represent the initial stage of a mound buildup or one that never fully developed. It contains dolomitized and brecciated algal plates, marine cements, and internal sediments suggesting subaerial exposure. Proto-mound/collapse breccia lithofacies are usually near phylloid-algal mound lithofacies, but generally lack any significant porosity. They may appear as promising buildups on seismic, but in actuality have little potential other than as guides to nearby fully developed mounds (figure 10-9). In the upper Ismay zone, most phylloid-algal mounds developed adjacent to widespread intra-shelf (anhydrite-filled) basins (figures 10-7 and 10-8). Porous Desert Creek mound lithofacies, such as the reservoir for Bug field, occurs in linear bands that appear to be shorelines (carbonate islands) that developed on the middle shelf (figure 10-9). Regional lithofacies mapping clearly defines anhydrite-filled, intra-shelf basins. Inner shelf/tidal flat and associated productive, phylloid-algal mound lithofacies trends of the Ismay are present around the anhydritic salinas of intra-shelf basins (figures 10-7 and 10-8).

Aneth Platform Desert Creek Zone Subplay

Three generalized, regional depositional environments (lithofacies) are identified in the Aneth platform Desert Creek zone subplay (figures 10-10 and 10-11): (1) open-marine, (2) shallow-shelf/shelf-margin, and (3) intra-shelf, salinity-restricted (Chidsey and others, 1996c). The open-marine lithofacies includes open-marine buildups (typically crinoid-rich mounds), open-marine crinoidal- and brachiopod-bearing carbonate muds, euxinic black shales, wall complexes, and detrital fans. Sediments in the open-marine environment were deposited at water depths between 45 and 120 feet (14-37 m). This depositional environment is the most extensive and surrounds the shallow-shelf/shelf-margin depositional environment.

The shallow-shelf/shelf-margin depositional environment includes shallow-shelf buildups (phylloid algal, coralline algal, bryozoan, and marine-cemented buildups [mounds]), calcarenites (beach, dune, and stabilized grain flats, and oolite banks), and platform-interior carbonate muds and sands. Sediments were deposited at water depths between 0 and 40 feet (0-12 m). Karst characteristics are occasionally present over mounds. Tubular tempestites (burrows filled with coarse sand as a result of storm pumping) are found in some carbonate muds and sands. Most oil

fields in the Aneth platform Desert Creek zone subplay are located within lithofacies representing this depositional environment, including the giant Greater Aneth field (figures 10-10 and 10-11).

The intra-shelf, salinity-restricted depositional environment represents small sub-basins within the shallow-shelf/shelf-margin depositional environment. The water had slightly elevated salinity compared to the other depositional environments. This depositional environment includes platform-interior evaporites, dolomitized tidal-flat muds, bioclastic lagoonal muds, tidal-channel carbonate sands and stromatolites, and euxinic dolomites. Sediments were deposited at water depths between 20 and 45 feet (6-14 m). Euxinic dolomites often display karst characteristics. Two intra-shelf sub-basins have been identified in the southeastern part of the Paradox Basin in Utah; each is separated from the open-marine by a fringe of the shallow-shelf/shelf-margin (figure 10-10).

Within the depositional environments described above and shown on figure 10-6, three local Desert Creek lithofacies are common: platform-interior carbonate sands and muds, platform-margin calcarenites, and carbonate buildups (figure 10-11) (Chidsey and others, 1996c). The platform-interior carbonate mud and sand lithofacies is widespread across the shallow shelf. This lithofacies represents a low- to moderate-energy environment. Mud and sand were deposited in subtidal (burrowed), inter-buildup, and stabilized grain-flat (pellet shoals) settings intermixed with tubular and bedded tempestites. Water depths ranged from 5 feet to 45 feet (1.5-14 m). The platform-margin calcarenite lithofacies is located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. This lithofacies represents a high-energy environment where shoals and/or islands developed as a result of regularly agitated, shallow-marine processes on the shelf. Characteristic features of this lithofacies include medium-scale cross-bedding and bar-type, carbonate, sand-body morphologies. Water depth ranged from sea level to 20 feet (6 m). Stabilized calcarenites occasionally developed subaerial features (up to 5 feet [1.5 m] above sea level) such as beach rock, hard grounds, and soil zones.

Productive carbonate buildups are located in the shallow-shelf/shelf-margin areas. These buildups can be divided into three lithofacies types: (1) phylloid algal, (2) coralline algal, and (3) bryozoan (Eby and others, 1993; Chidsey and others, 1996c). The controls on the development of each buildup type were water depth, prevailing wave energy, and paleostructural position. The phylloid-algal buildup, the dominant producing reservoir lithofacies, represents a moderate-energy environment with well-circulated water. Water depths ranged from 1 to 40 feet (0.3-12 m). Mapping of seismic anomalies and reservoir thicknesses indicates that carbonate phylloid-algal buildups, or mounds, were doughnut or horseshoe shaped, or a composite of the two shapes (figures 10-12 and 10-13). Many of the phylloid-algal buildups were large enough to enclose interior lagoons. The Desert Creek at Greater Aneth field was deposited as a horseshoe-shaped buildup of numerous coalescing mounds capped by banks of oolitic sands, similar to the present-day Bahamas open-marine, carbonate-shelf system. Coralline-algal buildup lithofacies is located along shallow-shelf margins facing open-marine waters or within the intra-shelf, salinity-restricted lithofacies belt (where they are non-productive). On the shallow shelf, this facies represents a low- to high-energy environment with well-circulated water. Water depths ranged from 25 to 45 feet (8-14 m). These buildups are a component of the wall complex (figure 10-11) in association with early marine cementation and are stacked vertically. They may surround other types of buildup complexes. Bryozoan buildup lithofacies is located on the deeper flanks of phylloid-algal buildup complexes (figure 10-14A). This lithofacies represents a low-energy environment with well-circulated water. Water depths ranged from 25 to 45 feet (8-14 m). This

lithofacies is prevalent on the shallow shelf where winds from the east, and paleotopography from Mississippian-aged normal faulting, produced better marine conditions for bryozoan colony development.

The principal buildup process for phylloid-algal growth occurred during sea-level highstands (figure 10-14A) (Chidsey and others, 1996c). Phylloid-algal mounds generally developed on platform-interior carbonate mud and sand. The mound substrate of platform-interior carbonates is referred to as the platform interval. Calcified phylloid-algal plates sheltered abundant primary "vugs," with mounds of phylloid algae building upward within the available accommodation space. As mounds grew, detrital skeletal material was shed and deposited as dipping beds along the exterior flanks and within interior lagoons. The floors of the interior lagoons consisted of muddy, marine limestone with fossils. Early marine cementation commonly occurred along mound walls facing open-marine environments. Bryozoan-dominated buildups developed in deeper water along the flanks of phylloid-algal mounds. Coralline-algal buildups developed in association with marine-cemented walls and detrital-fan complexes.

During sea-level lowstands, these buildups experienced considerable porosity modification (figure 10-14B). Leached cavities, vugs, and seepage-reflux dolomites developed in the mound core and flank sediments. Evaporitic dolomite and anhydrite filled the interior lagoons. Islands consisting of high-depositional-energy calcarenites and low-depositional-energy stromatolites, as well as troughs representing tidal channels, formed on the top of buildups during times of subaerial exposure (figures 10-14B and 10-14C). These high-energy portions of buildups are referred to as supra-mound intervals.

Stratigraphy and Thickness

The Paradox Formation is part of the Pennsylvanian Hermosa Group (Baker and others, 1933) (figure 10-2). The 500- to 5000-foot-thick (150-1500 m) Paradox is overlain by the Honaker Trail Formation and underlain by the Pinkerton Trail Formation (Wengerd and Matheny, 1958; Hintze, 1993). The Paradox is divided into (1) a lower member consisting of interbedded black shale, siltstone, dolomite, and anhydrite, (2) a middle (saline) member consisting of thick halite interbedded with dolomite, dolomitic siltstone and shale, and anhydrite, and (3) an upper member of interbedded dolomite, dolomitic shale, and anhydrite.

Hite (1960) divided the middle (saline) member of the Paradox Formation in the evaporite basin into as many as 29 salt cycles that onlap onto the basin shelf to the west and southwest. Each cycle consists of a clastic interval/salt couplet. The clastic intervals are typically interbedded dolomite, dolomitic siltstone, organic-rich shale, and anhydrite. The clastic intervals typically range in thickness from 10 to 200 feet (3-60 m) and are generally overlain by 200 to 400 feet (60-120 m) of halite. In the interior of the basin, a typical cycle consists of a black shale facies overlain almost entirely by salt, whereas on the shelf, a cycle consists of a black shale facies overlain primarily by carbonates. The regionally extensive black shale facies allows correlation of salt cycles in the interior of the basin with carbonate cycles on the shelf.

Hite and Cater (1972) and Reid and Berghorn (1981) divided the Paradox Formation into informal zones, in ascending order: Alkali Gulch, Barker Creek, Akah, Desert Creek, and Ismay (figure 10-2). This usage is currently the most common in the literature, as well as in completion and production reports.

The Cane Creek shale, the only current oil-producing unit in the fractured shale subplay, is the basal part of cycle 21 and generally ranges from nothing to about 160 feet (48 m) thick.

The depositional strike of the Cane Creek is northwest to southeast, and it thins to the southwest where it laps onto the lower Paradox member or the Pinkerton Trail Formation. Thickness variations are the results of diapiric salt movement, depositional thickening on the downthrown side of faults, or depositional thinning on the upthrown side of faults (figure 10-15). The Cane Creek is divided into sub-units in descending order: A, B, and C. The Cane Creek is overlain and generally underlain by anhydrite and halite (figure 10-16).

In the Blanding sub-basin (figures 10-3 and 10-4), the Desert Creek and Ismay zones are relatively easy to correlate because they are bounded by persistant shale or other units that have distinctive geophysical log responses (figures 10-17 and 10-18). The Desert Creek zone is typically dolomite, while the Ismay is mainly limestone with some dolomite units. The average thickness of the Desert Creek zone is 85 feet (24 m). It is overlain by the Gothic shale and underlain by the Chimney Rock shale, both informal units of the Paradox Formation (figure 10-17). The average depth to the Desert Creek in Blanding sub-basin fields is 5920 feet (1800 m). The average thickness of the Ismay zone is 230 feet (70 m). It is overlain by the Honaker Trail Formation and underlain by the Gothic shale (figure 10-18). The Ismay zone is subdivided into an upper interval and a lower interval separated by a 30- to 45-foot-thick (10-15 m) unit informally called the Hovenweep shale (figure 10-18). The average depth to the Ismay in Blanding sub-basin fields is 5630 feet (1880 m).

On the Aneth platform (figures 10-3 and 10-4), the Desert Creek and Ismay zones are predominately limestone, with local dolomitic units, and are the major producers in the area; the Akah and Barker Creek zones are minor producers in comparison. Like in the Blanding sub-basin, the Desert Creek is again overlain by the Gothic shale and underlain by the Chimney Rock shale. The geophysical log response has variations that correspond to changes in lithofacies (figure 10-19). As a result, the Desert Creek is often subdivided into informally named sub-intervals in the larger fields. Thickness of the Desert Creek zone averages 140 feet (45 m). The average depth to the Desert Creek in Aneth platform fields is 5530 feet (1840 m). The Ismay zone is again overlain by the Honaker Trail Formation and underlain by the Gothic shale. The Ismay geophysical log response also has variations that correspond to changes in lithofacies; however, the Hovenweep shale is not well developed in this part of the Paradox Basin (figure 10-20). Thickness of the Ismay zone averages 160 feet (50 m). The average depth to the Ismay in Aneth platform fields is 5320 feet (1770 m).

Lithology

Fractured Shale Subplay

In the Cane Creek shale (figure 10-16), unit A is composed of alternating thin beds (1 to 4 feet [0.3-1.2 m] thick) of silty carbonate with interbedded, gray to black shale and laminated to nodular anhydrite. Unit B, the primary fractured oil reservoir unit, is composed of interbedded, gray and black shale, and silty to sandy carbonate. Unit C is composed of interbedded silty carbonate and anhydrite.

Blanding Sub-Basin Ismay and Desert Creek Zones Subplays

Open-marine lithofacies is found in both the Ismay and Desert Creek zones of the Blanding sub-basin (figures 10-7 through 10-9, and 10-21). Rock representing this lithofacies

consists of lime mudstone containing well-preserved rugose corals, crinoids, brachiopods, bryozoans, articulated thin-shelled bivalves, and benthic forams indicative of normal-marine salinity and low-energy conditions. Rock units of this lithofacies have very little effective porosity and permeability, and act as barriers and baffles to fluid flow.

Middle-shelf lithofacies is also found in both the Ismay and Desert Creek zones (figure 10-22). The most common depositional fabrics of this lithofacies are bioturbated lime to dolomitic mudstone with ubiquitous sub-horizontal feeding burrows, and fossiliferous peloidal wackestone. There are few megafossils and little visible matrix porosity. However, there is some fusulinid-rich lime wackestone to packstone also present in very tight, biogenically graded limestone.

Inner shelf/tidal flat lithofacies is found in the Ismay zone as dolomitized packstone and grainstone (figure 10-23). Clotted, lumpy, and poorly laminated microbial structures resembling small thrombolites and intraclasts are common. Megafossils and visible porosity are very rare in the inner shelf/tidal flat setting. Non-skeletal grainstone (calcarenite) composed of ooids, coated grains, and "hard peloids" occurs as high-energy deposits in some inner shelf/tidal flat settings. Remnants of interparticle and moldic pores may be present in this lithofacies.

Bryozoan mound lithofacies is found in the Ismay zone as mesh-like networks of tubular and sheet-type (fenestrate) bryozoans (figure 10-24). These bryozoans provide the binding agent for lime mud-rich mounds. Crinoids and other open-marine fossils are common. Large, tubular bryozoans and marine cement are also common in areas of high-energy, and possibly shallow, water. Porosity is mostly confined to preserved intraparticle spaces.

Phylloid-algal mound lithofacies is found in both the Ismay and Desert Creek zones (figures 10-7 through 10-9, and 10-25). Very large phylloid-algal plates of *Ivanovia* (the dominant genus in the Ismay zone) and skeletal grains create bafflestone or bindstone fabrics. In mound interiors, algal plates are commonly found in near-growth positions surrounded by lime mud (figure 10-25A). On the high-energy margins of algal mounds, algal plates and skeletal grains serve as substrates for substantial amounts of botryoids and other early-marine cements, and internal sediments (figure 10-25B). Desert Creek mounds are dolomitized, contain plates of the *Kansasphyllum* (figure 10-25C), and show evidence of subaerial exposure (breccia or beach rock). Pore types include primary shelter pores preserved between phylloid-algal plates and secondary moldic pores.

Anhydrite salina lithofacies is found within locally thick accumulations in upper Ismay (upper and lower parts) intra-shelf basins (figures 10-7 and 10-8). Anhydrite growth forms include nodular-mosaic ("chicken-wire"), palmate, and banded anhydrite (figure 10-26). Large palmate crystals probably grew in a gypsum aggregate indicative of subaqueous deposition. Detrital and chemical evaporites (anhydrite) fill in the relief around palmate structures. Thin, banded couplets of pure anhydrite and dolomitic anhydrite are products of very regular chemical changes in the evaporite intra-shelf basins. These varve-like couplets are probably indicative of relatively "deep-water" evaporite precipitation.

Aneth Platform Desert Creek Zone Subplay

Platform-interior carbonate mud and sand lithofacies is represented by grainstone, packstone, wackestone, and mudstone fabrics. Rocks representing this lithofacies typically contain the following diagnostic constituents: soft-pellet muds, hard peloids, grain aggregates, crinoids and associated skeletal debris, and fusulinids. The platform-interior carbonate mud and

sand lithofacies can contain reservoir-quality rocks if dolomitized. However, effective porosity and permeability are highly variable.

Calcarenite lithofacies include grainstone (figures 10-27 and 10-28) and packstone fabrics. Rocks representing this facies typically contain the following diagnostic constituents: oolites, coated grains, hard peloids, bioclastic grains, shell lags, and intraclasts.

Phylloid-algal buildup lithofacies can be subdivided into shelter, mud-rich, and solution breccia lithofacies. Rocks representing shelter, phylloid-algal buildup lithofacies contain in-place phylloid-algal plates (*Ivanovia* and *Eugonophyllum*), encrusting forams (for example *Tetrataxis*), soft peloidal mud, and minor amounts of internal sediment (mud or grains deposited after storms [suspended load]). The depositional fabric is predominantly bafflestone (figure 10-29). These rocks have a high faunal diversity. The mud-rich, phylloid-algal buildup lithofacies is represented by bafflestone, wackestone, and mudstone fabrics. Rocks of this lithofacies contain in-place phylloid-algal plates surrounded by lime mud, fine skeletal debris, and microfossils. The solution breccia, phylloid-algal buildup lithofacies includes disturbed rudstone and floatstone with some packstone fabrics. Rocks of this lithofacies contain chaotic phylloid-algal and exotic clasts, peloids, and internal sediments (muds).

Coralline-algal buildup lithofacies consists of selectively dolomitized bindstone, boundstone, and framestone fabrics. Rocks representing this facies contain calcareous, encrusting and bulbous coralline (red) algae, variable amounts of lime mud, microfossils, and calcispheres.

Bryozoan buildup lithofacies is represented by bindstone, bafflestone, and packstone fabrics that are rarely dolomitized. Rocks of this lithofacies contain the following diagnostic constituents: bryozoan colonies (*Chaetetes*), small rugose corals, scattered small calcareous sponges and phylloid-algal plates, microfossils, and lime muds.

Greater Aneth field (figure 10-4), Utah's largest oil producer, was discovered in 1956 and has produced over 440 million BO (70 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The primary reservoir at Greater Aneth field consists of limestone (algal boundstone/bafflestone and oolitic, peloidal, and skeletal grainstone and packstone) and finely crystalline dolomite. The Desert Creek zone in the unit is divided into two subzones: a lower interval composed predominantly of phylloid-algal buildup lithofacies, and an upper interval composed of oolitic-peloidal calcarenite lithofacies (figures 10-28 through 10-30) (Peterson and Ohlen, 1963; Babcock, 1978a, 1978b, 1978c, 1978d; Peterson, 1992; Moore and Hawks, 1993). These subzones create a west-northwest-trending reservoir buildup (figure 10-13).

Hydrocarbon Source and Seals

Hydrocarbons in Paradox Formation reservoirs were generated from source rocks within the formation itself. Organic-rich informal units, such as the Cane Creek, Hovenweep, Chimney Rock, and Gothic shales (figure 10-2), are well-established source rocks (Hite and others, 1984; Nuccio and Condon, 1996). These rocks are composed of black, sapropelic shale and shaley dolomite (Morgan, 1993b). The average total organic carbon (TOC) content of the black shale in Cane Creek shale is 15% with some samples containing up to 28% (Grummon, 1993). Unit B is both the primary source and reservoir for oil and gas in the Cane Creek (figure 10-16). The Chimney Rock shale has from 1 to 3% TOC and a mean vitrinite reflectance (R_o mean) of 1.3 to 2.5% (Hite and others, 1984; Peterson, 1992). The Gothic shale has from 1.5 to near 4% TOC and an R_o mean of 0.8 to 1.2% (Hite and others, 1984; Peterson, 1992). Other, deeper shale

facies in the Paradox Formation contain as much as 13% TOC (Hite and others, 1984). Peterson (1992) calculated a cumulative thickness of more than 1000 feet (330 m) of organic-rich rocks in the Paradox.

Hydrocarbon generation occurred during maximum burial in the Late Cretaceous and early Tertiary. Hydrocarbons were then expelled and subsequently migrated, primarily along fracture and fault planes, into carrier beds, structures, or carbonate buildups (stratigraphic traps).

Vertical reservoir seals for the Paradox producing zones are shale, halite, and anhydrite within the formation; lateral seals are permeability barriers created by unfractured, off-mound (non-buildup) mudstone, wackestone, and anhydrite. In the fractured shale subplay, upper and lower seals are provided by anhydrite and halite. Lateral seals are permeability barriers in unfractured rock.

Structure and Trapping Mechanisms

In the fractured shale subplay, the oil is trapped in the Cane Creek shale (and possibly in other fractured units) on anticlines and along structural noses (figures 10-31 through 10-33). The northern Paradox Formation is mostly salt which can be highly deformed (figure 10-34).
Second-order folds due to salt flowage have amplitudes of 15 to 100 feet (5-30 m) and apparent wavelengths of 300 to 1000 feet (90-300 m). They are aligned directly over local budges of Paradox salt rather than the massive salt walls described by Doelling (1988, 2000). The overlying rocks were fractured and extended by minor faults just off the crests of the anticlines. Salt movement progresses along zones of weakness or areas of low confining pressure, forming large folds such as the Cane Creek and Shafer anticlines. The weak zones likely developed above and along the northwest-trending basement faults in the region which experienced periodic movement during both the Laramide and earlier Cretaceous Sevier (to the west) orogenies. Salt-cored anticline development has been active intermittently from the Pennsylvanian to the present day (Shoemaker and others, 1958; Cater, 1970; Case and Joesting, 1973; Friedman and others, 1994; Baars and Doelling, 1987; Doelling, 1988; Oviatt, 1988). Fracture data from oriented cores in the Cane Creek shale show a regional, northeast to southwest, near-vertical, open, extensional fracture system that is not significantly affected by orientations of localized folds (Grove and Rawlins, 1997). Hydrocarbon production from the Cane Creek is not limited strictly to the tops of anticlines. Production also has been established from structurally high positions on upthrown fault blocks and on the downthrown side of faults. Plunging noses without apparent four-way closure produce from the Cane Creek shale as well. Individual traps may exist in any structural position where fracturing of the self-sourced Cane Creek shale has occurred.

Trap types in the Blanding sub-basin and Aneth platform regions include stratigraphic, stratigraphic with some structural influence, combination stratigraphic/structural, and diagenetic. Regional dip is gently to the north-northeast towards the center of the basin. Hydrocarbons are most often stratigraphically trapped in porous and permeable rocks within Ismay and Desert Creek carbonate buildups described earlier. The trap is formed as these buildups rapidly thin and grade laterally into impermeable mudstone, wackestone, and anhydrite. They are effectively sealed by impermeable platform intervals at the base and a relatively thick layer of anhydrite (20 feet [6 m]) or shale (for example, the 50-foot-thick [15 m] Gothic shale above the Desert Creek zone) at the top. The best stratigraphic traps in the region are associated with phylloid-algal buildup and associated calcarenite lithofacies. These traps are widely distributed, generally small to moderate in size (200 to 2000 acres [80-800 ha]), and can be readily identified on

seismic records. However, Greater Aneth field is the exception in terms of size (figures 10-1 and 10-4), and is Utah's largest oil producer. Structural relief is often shown on top of structure maps for the Desert Creek zone (or the Ismay zone) at Greater Aneth (figure 10-35) and numerous other fields in the region. However, this relief is created by the variations between the thick mound, or carbonate buildup, and thinner off-mound lithofacies (figure 10-13) (Babcock, 1978a). Overlying units are generally thin and drape over the buildup; however, there is usually no surface expression of these features.

Many carbonate buildups appear to have developed on subtle anticlinal noses or structural closures (figure 10-36). These structures may represent paleobathymetric highs formed by pre-Pennsylvanian reactivation of basement faults, or simply longshore current-formed mudbars on the Paradox shallow-marine shelf (Babcock, 1978a). These "highs" provided the substrate for algal growth and mound buildup. An opposing origin is presented by Matheny and Longman (1996). They contend that fields such as Bug (figure 10-37), Cutthroat, Island Butte, and Spargo (figure 10-4) produce from phylloid-algal buildups deposited in sea-floor lows resulting from dissolution of halite in the underlying Akah zone (figure 10-2). Phylloid-algal lithofacies thickness was dictated by the timing and amount of halite dissolution – the greater the halite dissolution during algal growth, the thicker the potential reservoir (Matheny and Longman, 1996).

In some instances, stratigraphic traps have been enhanced by true structural relief, fracturing, and minor normal faults. Other traps include carbonate buildups located directly on anticlines. For example, Desert Creek field (figure 10-4) produces from a carbonate-buildup reservoir located directly on the crest of a north-northwest to south-southeast-trending anticline with 300 feet (100 m) of four-way closure (figure 10-38). A 500-foot (150 m), down-to-the-east normal fault parallels the west flank of the structure. Production from other anticlinal traps on the Aneth platform is found at Tohonadla in San Juan County, Utah (Norton, 1978b), and Boundary Butte East in Apache County, Arizona (Dunn, 1978) (figure 10-4).

Diagenesis is commonly a major component of trap development and reservoir heterogeneity in the carbonate buildups of Blanding sub-basin and Aneth platform fields. Dolomitzation and the creation of microporosity can yield reservoir quality in carbonate fabrics that are typically non-productive, such as wackestone and packstone (Chidsey and others, 1996c; Eby and Chidsey, 2001; Chidsey, 2002; Chidsey and Eby, 2002). The reservoir at Bug field (figure 10-4) is an elongate, northwest-trending, dolomitized carbonate buildup in the lower Desert Creek zone. The trapping mechanism is primarily an updip porosity pinchout (figure 10-37).

Reservoir Properties

The Paradox Formation has heterogeneous reservoir properties because of (1) depositional lithofacies with varying porosity and permeability, (2) carbonate buildup (mound) relief and flooding surfaces (parasequence boundaries), and (3) diagenetic effects. The extent of these factors, and how they are combined, affect the degree to which they create barriers to fluid flow. Identification and correlation of depositional lithofacies and parasequences in individual Paradox reservoirs is critical to understanding their effect on water/carbon dioxide injection programs, production rates, and paths of petroleum movement.

Porosity and Permeability

Paradox porosity in carbonate reservoirs ranges from 7 to 16% with typical porosity averaging 11%. Permeability is highly variable, generally ranging from less than 1 up to 55 millidarcies (mD) with an average of 14 mD. At Greater Aneth field (figure 10-4), the porosity averages 10.2% (averaging 16.5% in selected intervals) and permeability ranges from less than 3 up to 30 mD, averaging 10 mD (Moore and Hawks, 1993). The Cane Creek shale in the Bartlett area has an average fractured shale porosity (matrix and fractures) of 2%; permeability ranges from 39 to 400 mD from Horner plots (Grove and others, 1993). Oriented core from the Cane Creek show two types of fracture sets: (1) large-scale northeast- to southwest-oriented fractures related to regional tectonics and salt movement, and (2) microfractures that resulted from internal hydrocarbon generation (Fritz, 1991). The larger tectonic fractures may account for most of the permeability, but the microfractures probably provide most of the fracture porosity in the reservoir.

Diagenesis and Pore Types

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing carbonate rocks of the Desert Creek and Ismay zones can be an indicator of reservoir flow capacity, storage capacity, potential for water- and/or CO_2-flooding, and horizontal drilling. The framework grains of carbonate buildups consist predominantly of phylloid-algal plates, with lesser amounts of brachiopods, bryozoans, pelloids, oolites, ostracods, and forams. They yield primary porosity such as shelter (figure 10-39), interparticle (figure 10-40), and intraparticle (particularly in bryozoan-dominated buildups) (figure 10-41) pore types. Where these pore types are well developed, the reservoirs have excellent hydrocarbon storage and fluid-flow capacity, and are good candidates for CO_2 flooding.

Most shallow-shelf/shelf-margin carbonate buildups, or mounds, had relief with exposure occurring when sea level fell. This setting produced four major, generally early, diagenetic environments (figure 10-42): (1) fresh-water (meteoric) vadose zone (above the water table, generally at or near sea level), (2) meteoric phreatic zone (below the water table), (3) marine phreatic zone, and (4) mixing zone (Longman, 1980). The “iceberg” principle (the Ghyben-Herzberg theory) – which is that for every foot the water table rises above sea level there may be 20 feet (6 m) of fresh water below the water table, a 1:20 ratio – can generally be applied to both carbonate-mound and island buildups (Friedman and Sanders, 1978). The typical early diagenetic events occurred in the following order (figure 10-43): (1) early marine cementation which may include first-generation micrite and fibrous isopachous cementation, second-generation botryoidal cementation, and third-generation radiaxial cementation (note: early-marine cements are not always present), (2) post-burial, replacement, rhombic dolomite cementation due to seepage reflux, (3) vadose and meteoric phreatic diagenesis including leaching/dissolution, neomorphism, and fresh-water cementation (dogtooth, stubby, and small equant calcite), (4) mixing-zone dolomitization, (5) syntaxial cementation, (6) anhydrite cementation/replacement, and (7) minor silica replacement.

That portion of the carbonate buildup facing the open-marine environment was generally a steep-wall complex where early-marine cements (such as fibrous isopachous, botryoidal, and radiaxial cements) were deposited from invading sea water flowing through the system and filled most original pore space (figures 10-42, 10-44, and 10-45). Locally, cemented zones can have a

major impact on reservoir flow and storage capacity. The opposite side of the mound typically bordered a hypersaline lagoon filled with dense brine that seeped into the phreatic zone (seepage reflux) to form a wedge-shaped zone of early, low-temperature dolomite – both early replacement dolomite and dolomite cement. Seepage reflux dolomization is usually complete dolomitization. Little original fabric/matrix remains. Crystals are fine to medium grained, often sucrosic; intercrystalline porosity dominates (figure 10-46). Seepage reflux overprints the fresh-water phreatic, marine phreatic, and mixing zones across the entire extent of the mound buildup. Thick seepage reflux dolomites are often proximal to evaporite-plugged lagoonal sediments. Locally, seepage reflux dolomitization can enhance both reservoir flow and storage capacity. Those reservoirs with excellent storage capacity may be considered candidates for CO_2 flooding projects.

The meteoric and marine phreatic zones were separated by a mixing zone (fresh and sea water), all of which changed with sea-level fluctuation. Most carbonate buildups have both a mixing-zone and fresh-water overprint. Some early dolomitization took place in the mixing zone (figure 10-47). Dissolution was the dominant porosity-enhancing process of meteoric diagenesis and created molds, vugs, and channels (figures 10-48 and 10-49). Much of the original fabric remains or can be determined. However, some grainstone, packstone, and calcarenite have only non-connected moldic pores that result in classic "heart break" reservoirs. Early dissolution of lime muds also created microporosity. Indicative cements include stubby to equant calcite and dogtooth calcite spars that sporadically line pores (figure 10-39). Vadose zones generally have less cement than the fresh-water phreatic zones. The depth/thickness of the meteoric vadose and fresh-water phreatic zones is dependent on the extent and duration of subaerial exposure as well as the amount of meteoric water influx. Locally, meteoric diagenesis enhances reservoir performance. Subaerial exposure of carbonate buildups, for example the Desert Creek zone at Bug field (figure 10-4), occasionally produced intense, early micro-box-work porosity. Figure 10-50 shows the pattern of patchy dolomite dissolution which includes a micro-box-work pattern of pores. Some of the pores in this view occur between elongate, rectilinear networks of dolomite laths. Micro-box-work porosity represents an important site for exploiting untapped hydrocarbons using horizontal drilling. Extensively leached intervals may have both excellent storage and flow capacity, and should be considered candidates for CO_2 flooding projects.

Post-burial diagenesis included additional syntaxial cementation, silicification, late coarse calcite spar formation, saddle dolomite cementation, stylolitization, additional anhydrite replacement, late dissolution (microporosity development), bitumen plugging (figure 10-43), and fracturing. There is an observed progression from least to most important (syntaxial cementation to anhydrite replacement) which relates to increased reservoir heterogeneity in Paradox reservoirs. Some of these diagenetic products create barriers and baffles to fluid flow, such as the case where anhydrite and bitumen (or solid hydrocarbons) plug pores and pore throats. They are not observed on seismic records, are difficult to predict, and locally influence reservoir performance, storage capacity, and drainage. Some reservoirs, the Ismay zone in Cherokee field for example (figure 10-4), display intense microporosity (figures 10-51 and 10-52) that developed late, along solution fronts by the action of aggressive hydrothermal solutions from depth (carbon dioxide escaping from Mississippian Leadville Limestone or from deep decarboxylation of organic matter). Microporosity increases storage capacity, but limits fluid recovery. Microporosity represents an important site for untapped hydrocarbons and possible targets for horizontal drilling.

Engineering Data

Paradox net-pay thickness is also variable, depending primarily on diagenesis, and ranges from 9 to 100 feet (3-30 m) averaging 35 feet (11 m). The average Paradox reservoir temperature is 126ºF (52ºC). Initial water saturations range from 25 to 50% (averaging 34%) (estimated at 10% for the fractured Cane Creek shale), salinities range from 80,000 to 349,000 parts per million, and resistivities (R_w) range from 0.045 to 0.07 ohm-m at 68ºF (20ºC). Initial reservoir pressures average about 2200 pounds per square inch (psi [15,000 kPa]). The Cane Creek is highly overpressured with fluid gradients exceeding 0.08 psi/ft (1.81 kPa/m); the initial reservoir pressures average 6650 psi (45,850 kPa). The reservoir drive mechanisms for Paradox reservoirs are predominantly solution gas but include gas-cap expansion, water drive, gas/pressure depletion, fluid expansion, and gravity drainage.

Well, production, and reservoir data for individual fields that have produced over 500,000 BO (80,000 m^3) in the Paradox Formation play are summarized in tables 10-1 and 10-2. For detailed summaries of these fields see Stowe (1972), Babcock (1978a, 1978b, 1978c, 1978d), Brown (1978, 1983), Campbell (1978a), Dunn (1978), Krivanek (1978, 1981, 1993), Lauth (1978a, 1978b), Mecham (1978a, 1978b), Mickel (1978a, 1978b, 1978c), Miesner (1978), Norton (1978b), Reid and Stevenson (1978), Riggs (1978), Smith (1978a, 1978b, 1978c, 1978d, 1978e), Spencer (1978), Wold (1978), Martin (1981, 1983), Lehman (1983), Ott and Roylance (1983), Scanlon and Wendling (1983), Matheny and Martin (1987), Dawson (1988), Herrod and Gardner (1988), Peterson (1992), Baars (1993), Crawley-Stewart and Riley (1993a, 1993b), Grove and others (1993), Lentz (1993), Moore and Hawks (1993), Ross and Handley (1993), Steele and White (1993), Chidsey and others (1996a), Oline (1996), Scott (2003), Colorado Oil & Gas Conservation Commission (2007), and Utah Division of Oil, Gas and Mining (2007).

Oil and Gas Characteristics

The produced Paradox oils are commonly sweet, paraffinic crudes. The API gravity of the oil ranges from 36º to 53º (averaging 43º); the gas-oil ratio ranges between 250 and 76,500 cubic feet/bbl. Oil colors are predominantly green, but can be dark to light green, brownish green, dark to yellowish to light reddish brown, straw yellow, or black. The viscosity of the crude oil averages 0.46 sus at 104ºF (40ºC). The pour point of the crude oil ranges from 0 to 50ºF (0-10ºC). The average weight percent sulfur and nitrogen of produced Paradox hydrocarbon liquids are 0.07 and 0.037, respectively (Stowe, 1972).

Paradox reservoirs produce associated gas that is fairly uniform in composition, averaging 66% methane, 16% ethane, 9% propane, 4% butane, 2% pentane, 1% hexane and higher fractions, 1% nitrogen, and 0.2% carbon dioxide, and occasionally a trace of hydrogen sulfide and helium (Moore and Sigler, 1987). The gas heating value averages 1400 British thermal units/cubic foot (Btu/ft^3); the specific gravity averages 0.794. One exception to the typical gas compositions in the Paradox is Akah field, San Juan County, Utah, where the reservoir contains 13% nitrogen and 18% carbon dioxide; the gas heating value is 863 Btu/ft^3 (Stowe, 1972; Moore and Sigler, 1987).

Oil and gas properties for individual fields that have produced over 500,000 BO (80,000 m^3) in the Paradox Formation play are summarized in tables 10-3 and 10-4.

Production

Thirteen fields in the fractured shale (Cane Creek shale) subplay have produced crude oil and associated gas (tables 10-5 and 10-6). Three fields have produced over 500,000 BO (80,000 m^3) (figure 10-15 and table 10-1). Prior to 1991, oil had been produced from 11 vertical wells perforated in the Cane Creek shale (table 10-5). All wells drilled and completed in the Cane Creek since 1991 have used horizontal drilling technology (table 10-6). The development history of the subplay has been described by Fritz (1991), Morgan and others (1991), Morgan (1992a, 1992b), Montgomery (1992), Grove and others (1993), Grummon (1993), Grove and Rawlins (1997), and Doelling and others (2000). Many vertical wells have been completed in the Cane Creek shale, but only the Long Canyon No. 1 well (section 8, T. 26 S., R. 20 E., Salt Lake Base Line and Meridian [SLBLM]) has been an economic success. The Long Canyon No. 1 well was drilled in 1962 and has produced more than 1 million bbls (159,000 m^3) of oil. The well is estimated to have produced more than 1 billion cubic feet (BCF [0.03 billion m^3]) of gas, but is not gauged due to a lack of a gas pipeline. Columbia Gas Development Corporation formed the Kane Springs Federal unit (figure 10-31), and in 1991 drilled the first horizontal well in the abandoned Bartlett Flat field, the Kane Springs No. 27-1 well (section 27, T. 25 S., R. 19 E., SLBLM). Exploration in the Kane Springs unit has resulted in numerous new field discoveries. Horizontal drilling has not resulted in wells that produce more oil than the Long Canyon well (figure 10-53), but has greatly improved the success rate of new economical discoveries.

Nine fields in the Blanding sub-basin Desert Creek zone subplay have produced crude oil and associated gas. These fields have combined to produce nearly 16 million BO (2.5 million m^3) and 67 BCFG (1.9 BCMG) from the Desert Creek zone (Scott, 2003; Colorado Oil & Gas Conservation Commission, 2008; Utah Division of Oil, Gas and Mining, 2008). There are currently about 50 active Desert Creek producers in these fields. Five fields have produced over 500,000 BO (80,000 m^3) (figure 10-4 and table 10-1).

Forty-five fields in the Blanding sub-basin Ismay zone subplay have produced crude oil and associated gas. These fields have combined to produce over 40 million BO (6.4 million m^3) and 105 BCFG (3.0 BCMG) from the Ismay zone (Scott, 2003; Colorado Oil & Gas Conservation Commission, 2008; Utah Division of Oil, Gas and Mining, 2008). There are currently about 130 active Ismay producers in these fields. A few scattered fields produce or are now abandoned in the Desert Creek zone. Fourteen fields have produced over 500,000 BO (80,000 m^3) from the Ismay zone (figure 10-4 and table 10-1).

Twenty-two fields – three in Arizona and the rest in Utah (figure 10-4) – in the Aneth platform Desert Creek zone subplay have produced crude oil and associated gas. These fields have combined to produce nearly 454 million BO (72 million m^3) and 416 BCFG (11.8 BCMG) (including cycled gas) from the Desert Creek zone; of this total over 440 million BO (70 million m^3) and 385 BCFG (10.9 BCMG) have been produced from Greater Aneth field (Utah Division of Oil, Gas and Mining, 2008). There are currently about 510 active Desert Creek producers in these fields; over 460 wells are in Greater Aneth field. Ten fields have produced over 500,000 BO (80,000 m^3) (figure 10-4 and table 10-1). There are several fields on the Aneth platform that have also produced from the Ismay zone, from commingled Ismay and Desert Creek zones, or the Akah and Barker Creek zones (several Arizona fields). However, most of these fields are abandoned: Anido Creek, Cleft, Rabbit Ears, Toh-Atin, Twin Falls, and Bita Creek fields, for example (figure 10-4).

In 2007, the monthly production from the Paradox Formation averaged 353,000 BO (56,000 m^3) and 0.5 BCFG (0.01 BCMG) (Colorado Oil & Gas Conservation Commission, 2008; Utah Division of Oil, Gas and Mining, 2008; Steve Rauzi, Arizona Geological Survey, written communication, 2008). Production peaks in the Paradox play have been strongly influenced by production at Greater Aneth field: in the late 1950s and early 1960s as the field was being developed, the onset of water and carbon dioxide floods in 1962 and 1985, respectively, and an extensive horizontal drilling program in the 1990s. Production also increased from a number of significant discoveries during the 1980s in the Blanding sub-basin Desert Creek and Ismay zones subplays (table 10-1). Production received boosts again in the 1990s with a series of discoveries in satellite mounds around Greater Aneth field. Production in the Blanding sub-basin Desert Creek and Ismay zones subplays has declined since 2000 due to maturing fields where no new enhanced oil recovery programs have been initiated. There have also not been any significant discoveries since the early 1990s due to limited exploratory drilling.

Big Flat field, discovered in 1957 with oil and gas production from the Mississippian Leadville Limestone, was abandoned in 1988. Later exploration in the area resulted in the discovery of oil in the shallower Cane Creek shale. The Big Flat No. 5 well (section 27, T. 25 S., R. 19 E., SLBLM) was completed in the Cane Creek in 1961, and was designated the Bartlett Flat field. The Big Flat No. 5 well was abandoned in 1965 due to collapsed casing after producing 39,393 bbls (6264 m^3) of oil. Two wells, the Husky No. 1 and Big Flat No. 6, were drilled within 100 feet (30 m) of the abandoned Big Flat No. 5 well, but were unable to establish economical oil production (figure 10-32). In 1991, Columbia Gas Development Corporation drilled the Kane Springs Federal No. 27-1 which included a 1012-foot (308 m) horizontal leg in the Cane Creek shale and passed within feet of the Big Flat No. 5 well. The Kane Springs No. 27-1 well was completed with an initial production rate flowing 914 bbls of oil per day (BOPD [145 m^3/d]) and 290 thousand cubic feet of gas per day (MCFGPD [8200 m^3/d]) from 7438 to 8240 feet (2267-2512 m) (7248 feet [2209 m] total true vertical depth). The discovery was designated Big Flat field. Two additional wells have been drilled in Big Flat field: the Kane Springs Federal No. 25-19-34-1 (section 34, T. 25 S., R. 19 E., SLBLM), completed in 1993, and the Kane Springs Federal No. 11-1 (section 11, T. 26 S., R. 19 E., SLBLM) completed in 2002. Cumulative production from the three horizontal wells, as of January 1, 2008, is 750,959 bbls (119,403 m^3) of oil and 0.74 BCFG (0.02 billion m^3) (Utah Division of Oil, Gas and Mining, 2008). There is no gas pipeline in the Big Flat area so the gas is vented except for what is used on location.

Exploration Potential and Trends

Fractured Shale Subplay

An important consideration in defining the exploration limits of the Cane Creek shale in fractured shale subplay may be the depositional limits of the underlying salt beds of cycles 22 through 29 (figure 10-2). Where it is not encased by thick, plastic salts that provide the reservoir seal, the Cane Creek may not be overpressured. In addition, fracturing of the Cane Creek by diapiric salt movement will not occur where the underlying salts were never present; the density of fracturing may thus be greatly reduced. If subsequent drilling supports this interpretation, then stratigraphic traps (pinchout or updip reduction of fractures) may occur where the underlying salt pinches out.

Exploration activity has been concentrated in areas where the Cane Creek shale has a history of production. Many of the earlier wells drilled in the area (figure 10-15) had excellent shows in the Cane Creek but were not completed in the shale because of poor production history, lower prices, and the lack of modern fractured shale completion technology. Horizontal drilling might also be used to test other fractured shale zones in the basin. Clastic intervals are associated with all of the 29 cycles in the Paradox Formation. Many of these units contain organic-rich black shales, some with TOC values of nearly 13%. In addition, oil or gas has been recovered from cycles 2 through 22 in the mapped area (figure 10-15). The Gothic and Chimney Rock shales (figure 10-2) also are excellent candidates for horizontal drilling. These shales are more than 40 ft (12 m) thick, are regionally extensive, and have numerous oil shows. Hite and others (1984) calculated that the Gothic shale has generated at least 4970 BO/acre (1950 m^3/ha).

Blanding Sub-Basin Ismay and Desert Creek Zones Subplays

Mapping the upper Ismay-zone lithofacies as two intervals (upper and lower parts) delineates very prospective reservoir trends that contain porous, productive carbonate buildups (figures 10-7 and 10-8). The mapped lithofacies trends clearly define anhydrite-filled, intra-shelf basins. Lithofacies and reservoir controls imposed by the anhydritic, intra-shelf basins should be considered when selecting the optimal location and orientation of any horizontal drilling for undrained reserves, as well as identifying new exploration trends. Projections of the inner shelf/tidal flat and mound trends around the intra-shelf basins identify potential exploration targets, which could be developed using horizontal drilling techniques (figures 10-54 and 10-55). Drilling horizontally from known phylloid-algal reservoirs along the inner shelf/tidal flat trend could encounter previously undrilled porous buildups. Intra-shelf basins are not present in the lower Desert Creek zone of the Blanding sub-basin (figure 10-9). However, drilling horizontally from productive mound lithofacies along linear shoreline trends could also encounter previously undrilled porous Desert Creek intervals and buildups.

Aneth Platform Desert Creek Zone Subplay

The shallow-shelf/shelf-margin depositional environment includes shallow-shelf carbonate buildups, platform-margin calcarenites, and platform-interior carbonate muds and sands (described earlier). Pervasive marine cement may be indicative of “wall” complexes suggesting potential nearby carbonate buildups, particularly phylloid-algal mounds (figure 10-42). Carbonate buildups, tidal-channel carbonate sands, and other features often appear promising on seismic records. However, if these carbonate buildups are located within the open-marine and intra-shelf, salinity-restricted depositional environments/lithofacies (figures 10-10 and 10-56), the reservoir quality is typically poor. Porosity and permeability development, if present, is limited or plugged with anhydrite, respectively in these depositional environments.

Platform-margin calcarenites are located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. Mapping indicates a relatively untested lithofacies belt of shallow-shelf, calcarenite carbonate deposits (figure 10-56). This narrow, but long, belt of calcarenites is between the open-marine and margins of intra-shelf, salinity-restricted depositional environments. Calcarenite buildups represent high-energy environments where shoals and/or islands developed. However, algal meadows, phylloid-algal buildups, and

stromatolite mats were also present in this lithofacies belt (figure 10-57) (Chidsey and Eby, 1997).

Heron field (figures 10-10 and 10-56) is an excellent example of the type of traps which potentially lie within the 20-mile-long (32 km) lithofacies belt described above. The trap for the field is a lenticular, northwest- to southeast-trending linear mound/beach complex, 0.8 mile (1.3 km) long and 0.5 mile (0.8 km) wide (Chidsey and others, 1996b). The reservoir consists of five units: (1) a basal, dolomitized, phylloid-algal (bafflestone) buildup, (2) an anhydrite-plugged, phylloid-algal (bafflestone) limestone buildup, (3) a fusulinid-bearing, lime-wackestone interval, (4) a dolomitized packstone interval with anhydrite nodules, and (5) a porous (15%), sucrosic, dolomitized grainstone and packstone interval. This last unit is the main reservoir, and consists of alternating 2- to 4-foot-thick (0.6-1.2 m) packages of uniform beach calcarenite and poorly sorted foreshore and storm-lag rudstone or breccia deposits.

Platform-margin calcarenite traps have both negative and positive characteristics for hydrocarbon production. Negative characteristics include (1) small reservoir size and storage capacity, (2) poor definition on seismic records, (3) limited distribution, (4) common bitumen plugging, and (5) rapid production declines. Positive characteristics include (1) excellent overall reservoir properties, (2) a common association with phylloid-algal buildups, (3) good potential for water/CO_2 floods, and (4) an extensive untested trend (Chidsey and Eby, 1997).

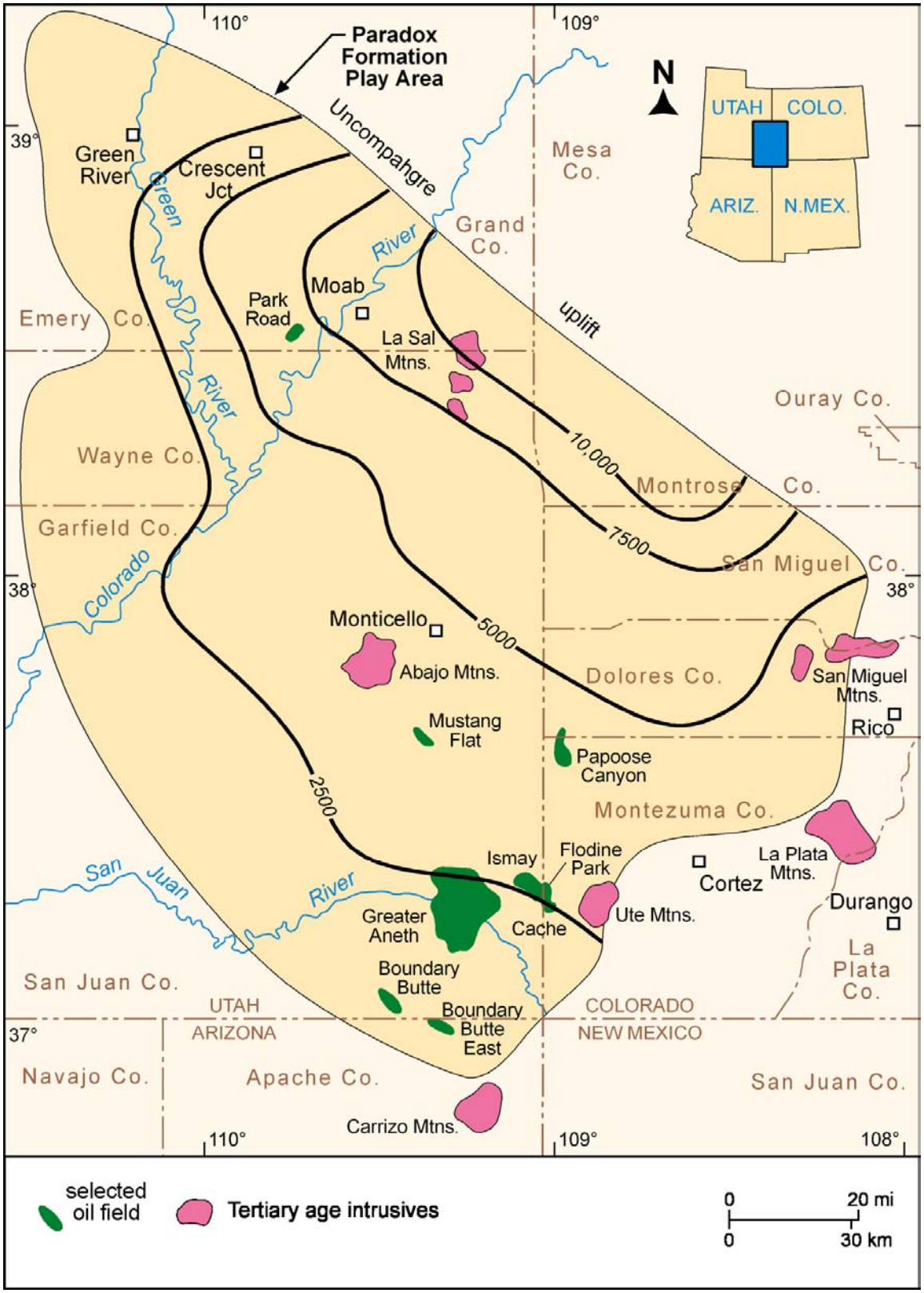


Figure 10-1. Pennsylvanian Paradox Formation play area and major fields, Utah, Colorado, and Arizona. Thickness of the Pennsylvanian rocks shown in feet. Modified from Choquette (1983).

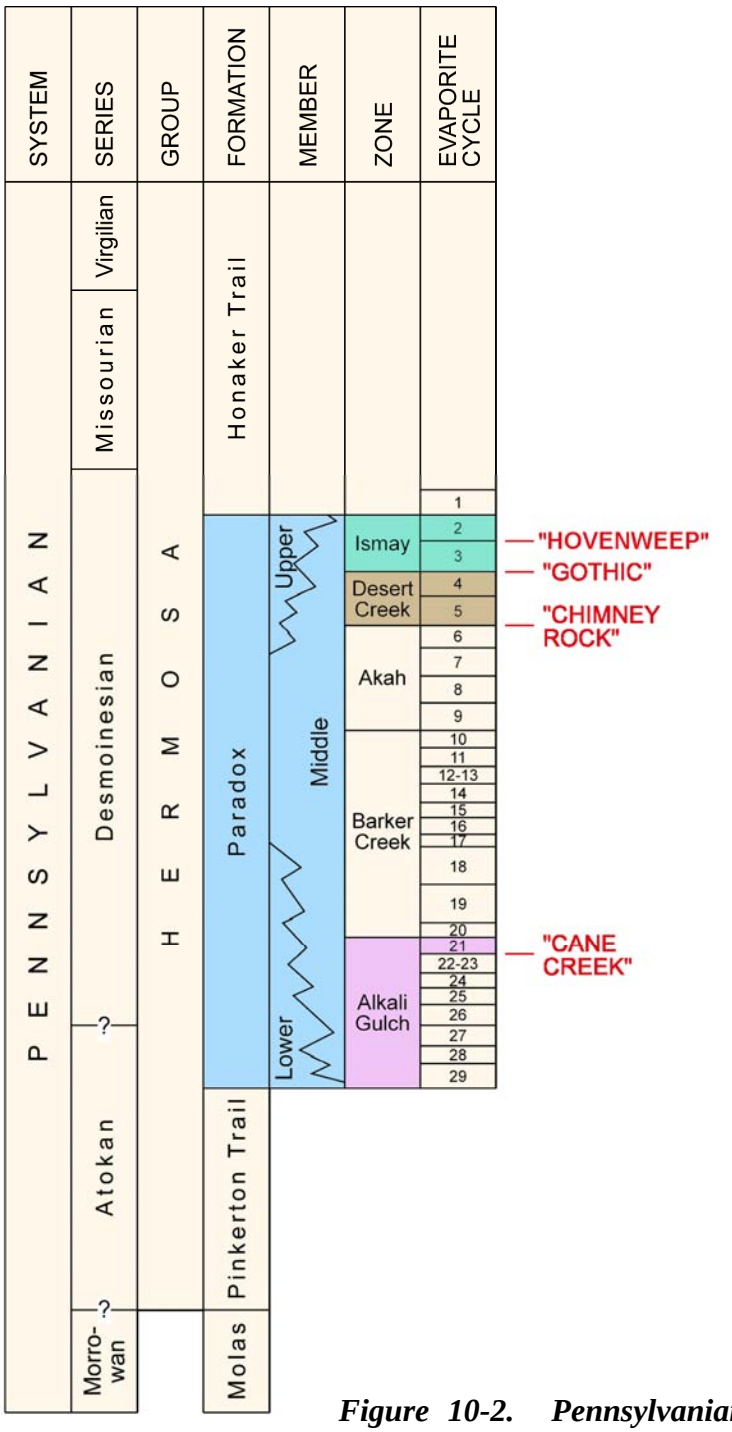


Figure 10-2. Pennsylvanian stratigraphic chart for the Paradox Basin; informal zones with significant production are highlighted with colors. Red text represents organic-rich shale intervals; the Cane Creek shale is a significant oil producer as well. Modified from Hite (1960), Hite and Cater (1972), and Reid and Berghorn (1981).

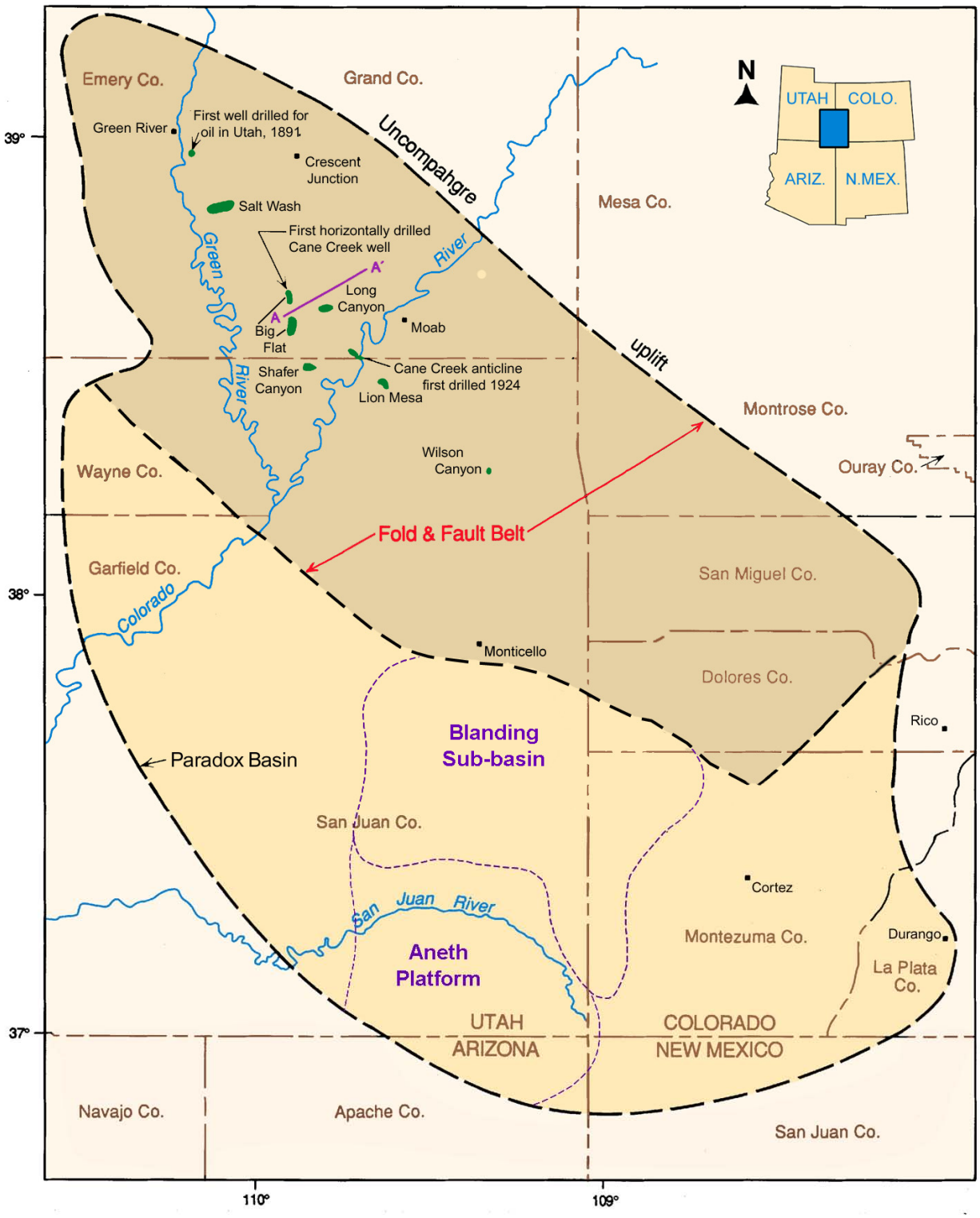


Figure 10-3. Location map of the Paradox Basin showing the fold and fault belt. Key fields are shown, solid green areas are productive from the Cane Creek shale of the Pennsylvanian Paradox Formation and open outlines are productive from the Mississippian Leadville Limestone. Line A – A' is figure 10-34.

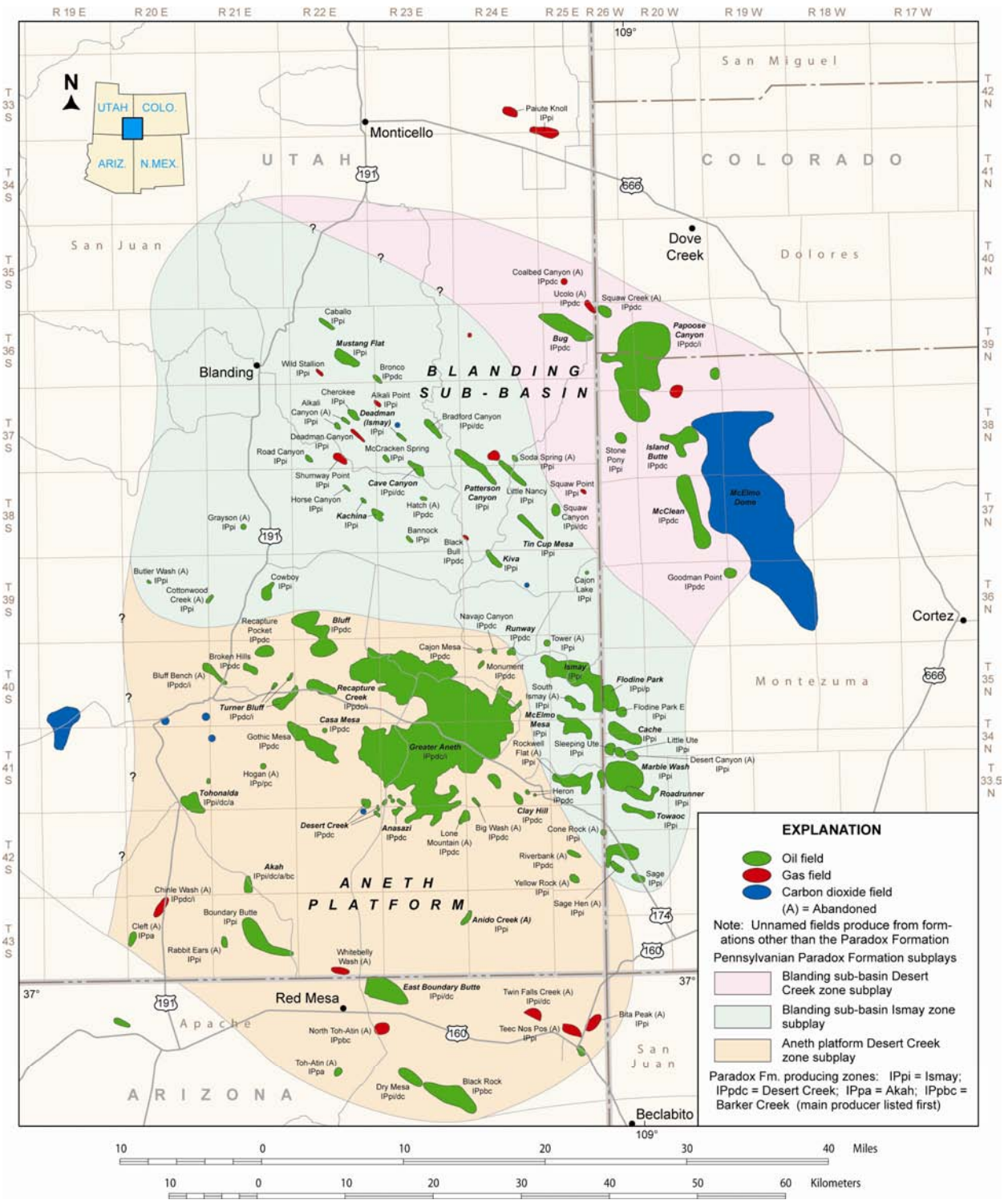


Figure 10-4. Location of the Paradox Formation Blanding sub-basin Desert Creek zone, Blanding sub-basin Ismay zone, and Aneth platform Desert Creek zone subplays, southeastern Utah, southwestern Colorado, and northeastern Arizona. The fractured shale subplay includes the entire Paradox Basin as shown on figure 10-1. Fields in italics have produced over 500,000 BO as of September 30, 2007. Modified from Wray and others (2002); Chidsey and others (2004).

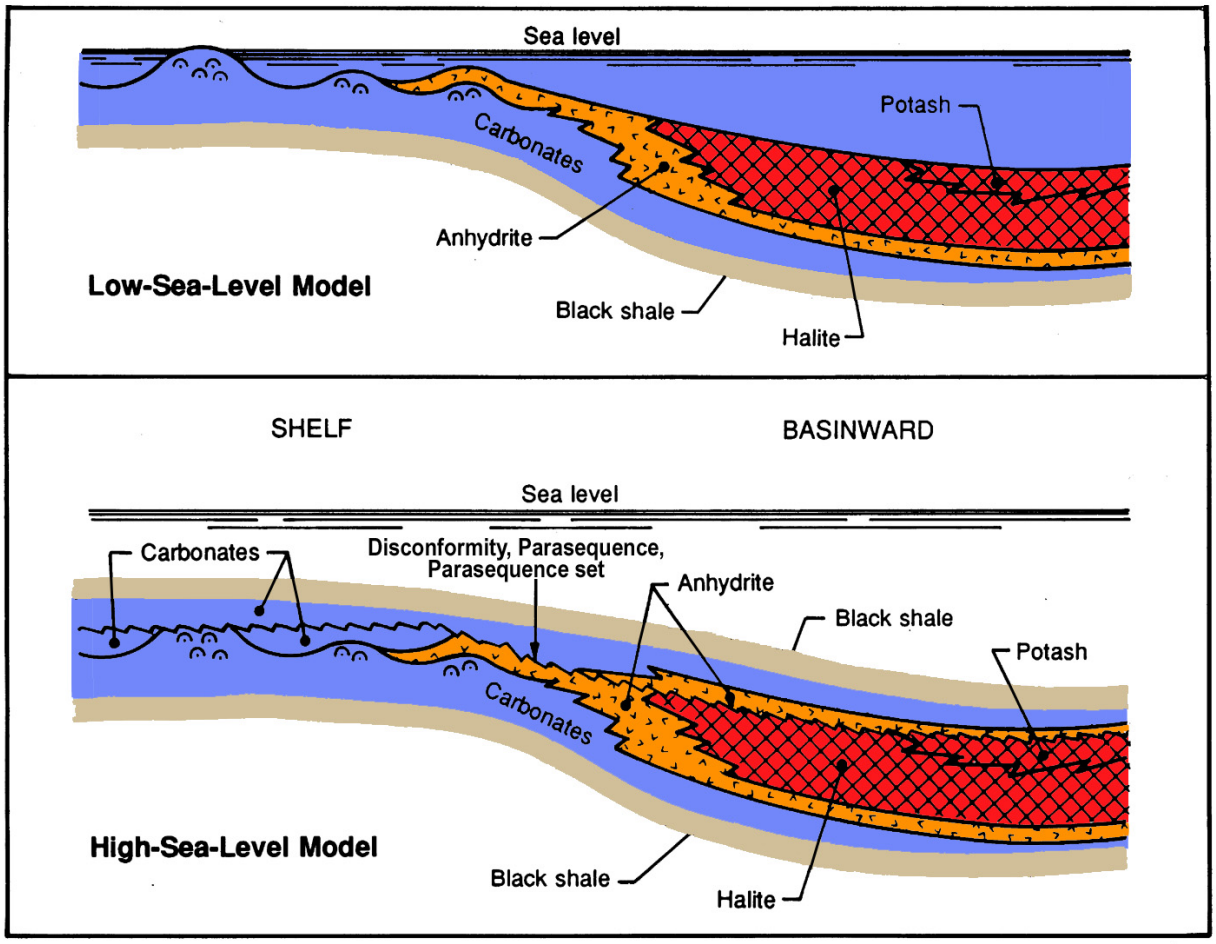


Figure 10-5. Diagram of the depositional sequence during Paradox time and the relationships of various basin and shelf facies. Wavy line represents disconformity, parasequence, or parasequence set. Symbol in the shelf carbonate represents algal-mound development. Modified from Hite and Cater (1972).

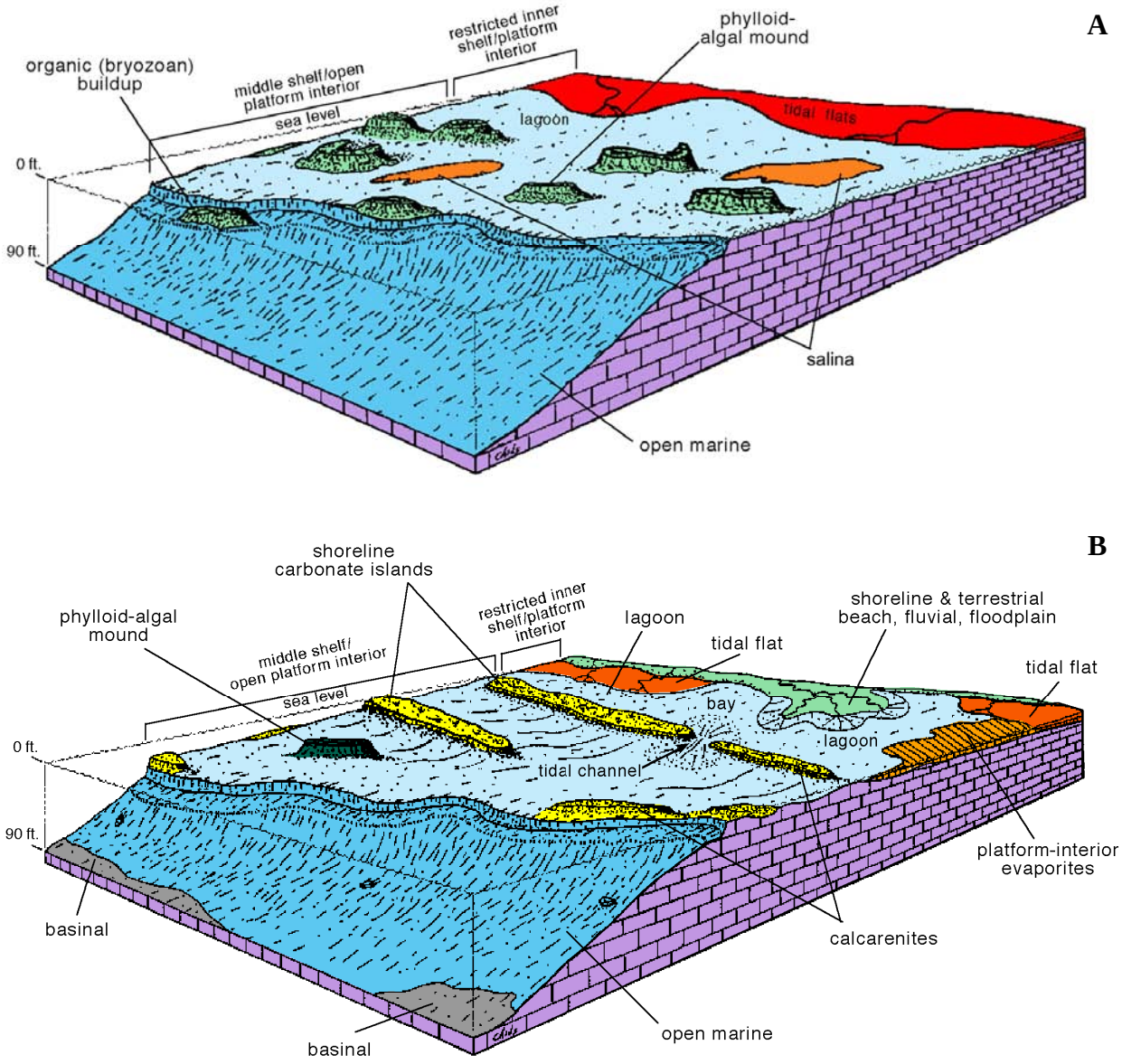


Figure 10-6. Block diagrams displaying major depositional environments, as determined from core, for the Ismay (A) and Desert Creek (B) zones, Pennsylvanian Paradox Formation, Utah and Colorado.

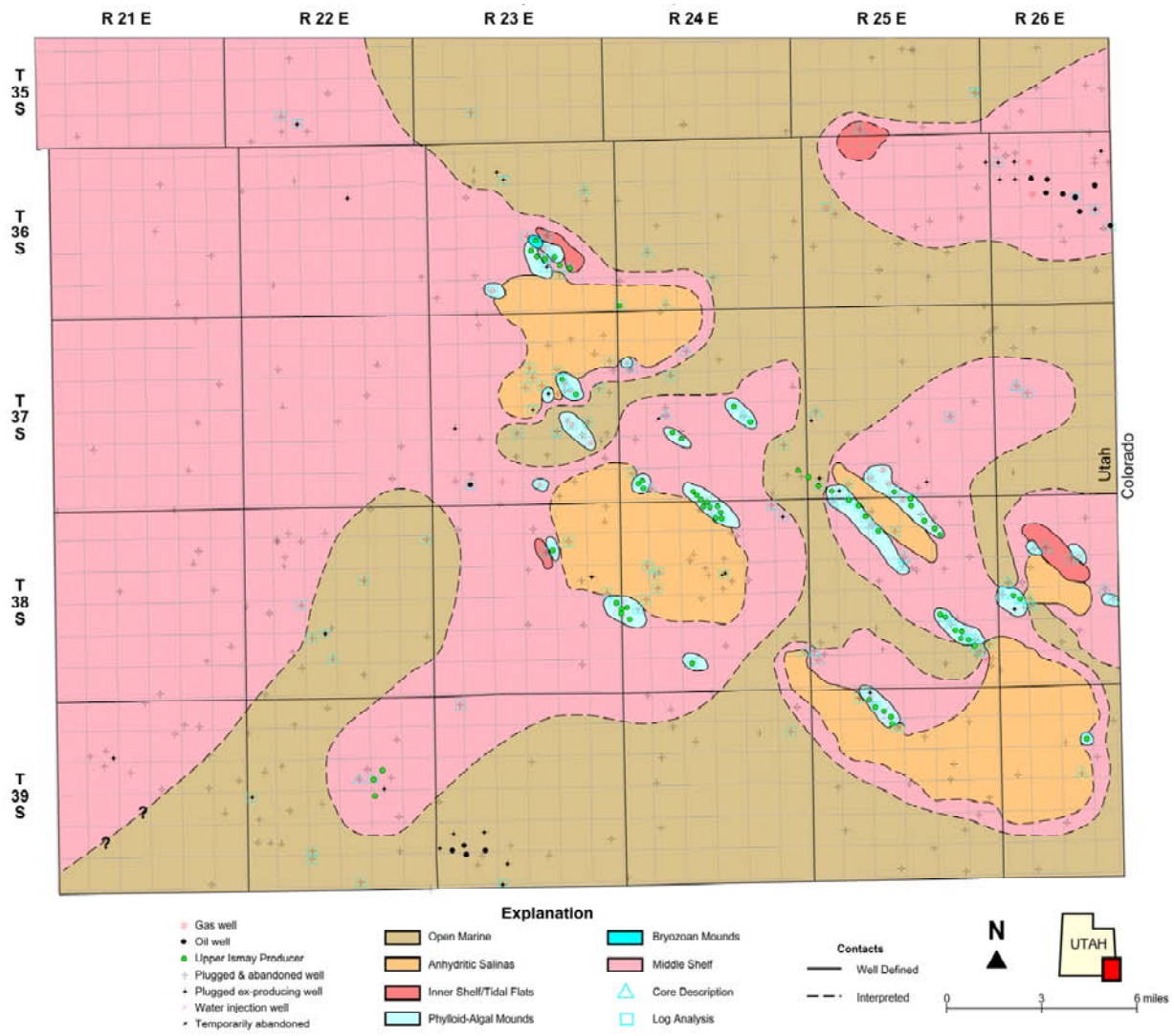


Figure 10-7. Regional lithofacies map of the upper part of the upper Ismay zone, Paradox Formation, in the Blanding sub-basin, Utah.

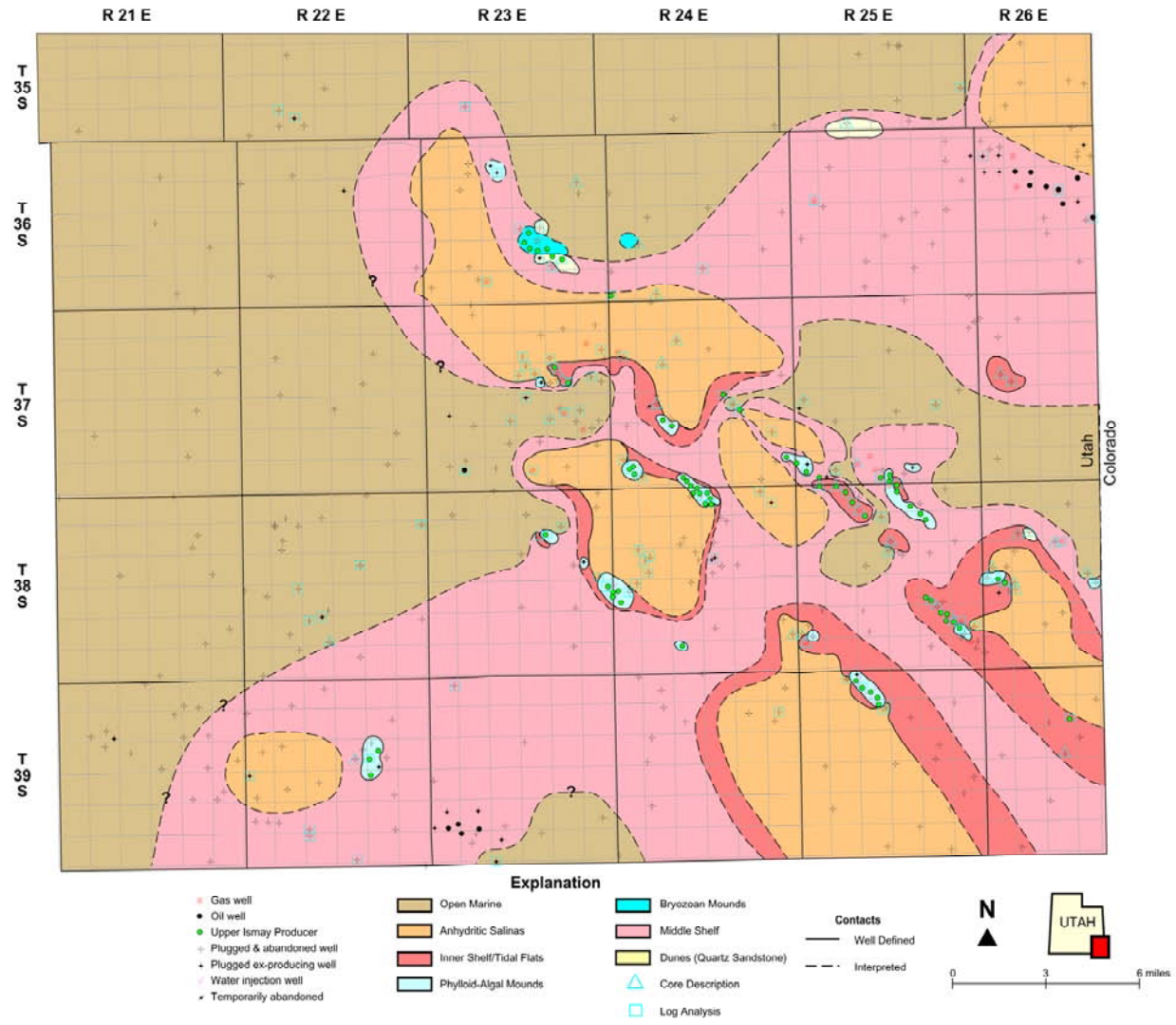


Figure 10-8. Regional lithofacies map of the lower part of the upper Ismay zone, Paradox Formation, in the Blanding sub-basin, Utah.

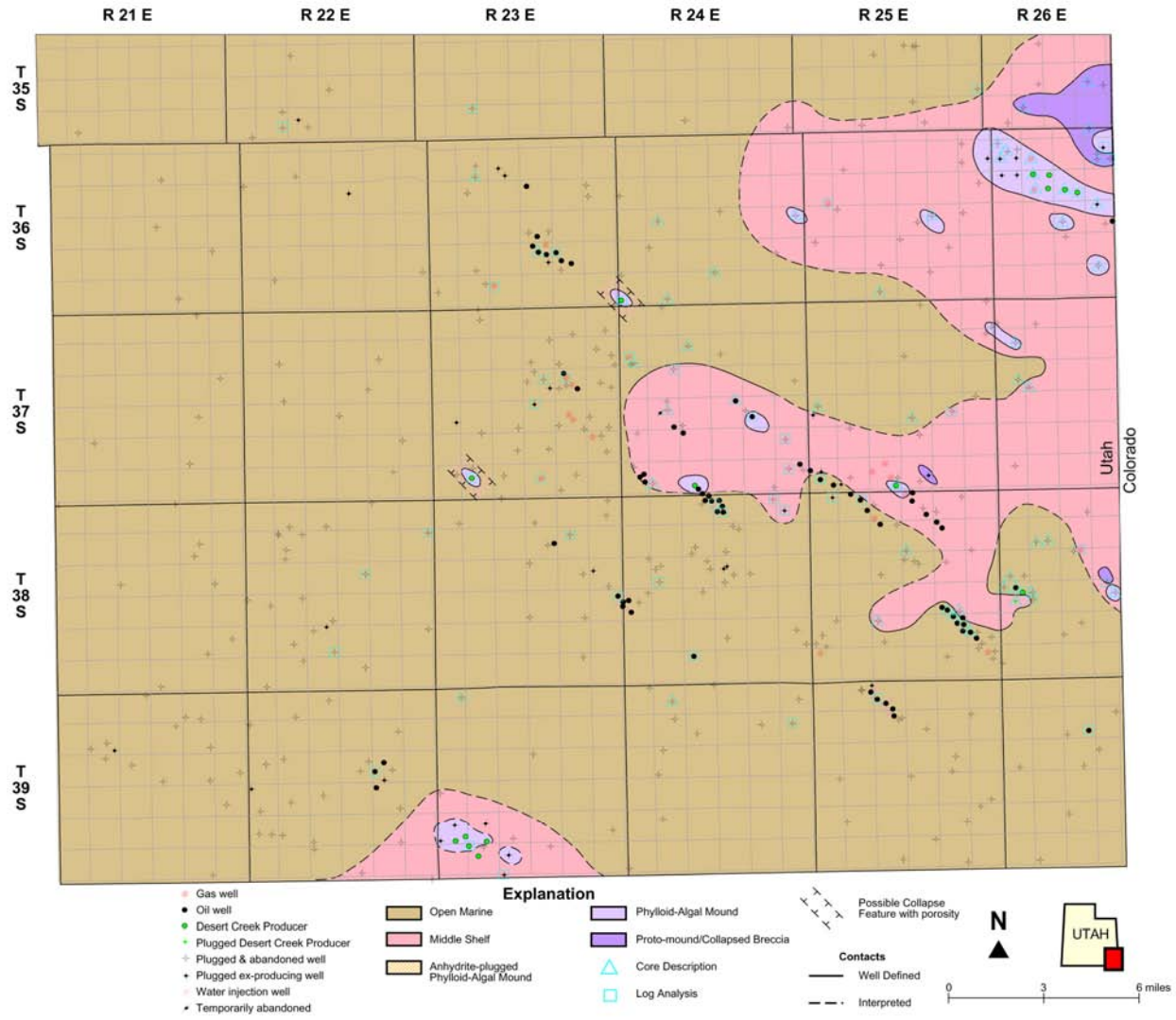


Figure 10-9. Regional lithofacies map of the lower Desert Creek zone, Paradox Formation, in the Blanding sub-basin, Utah.

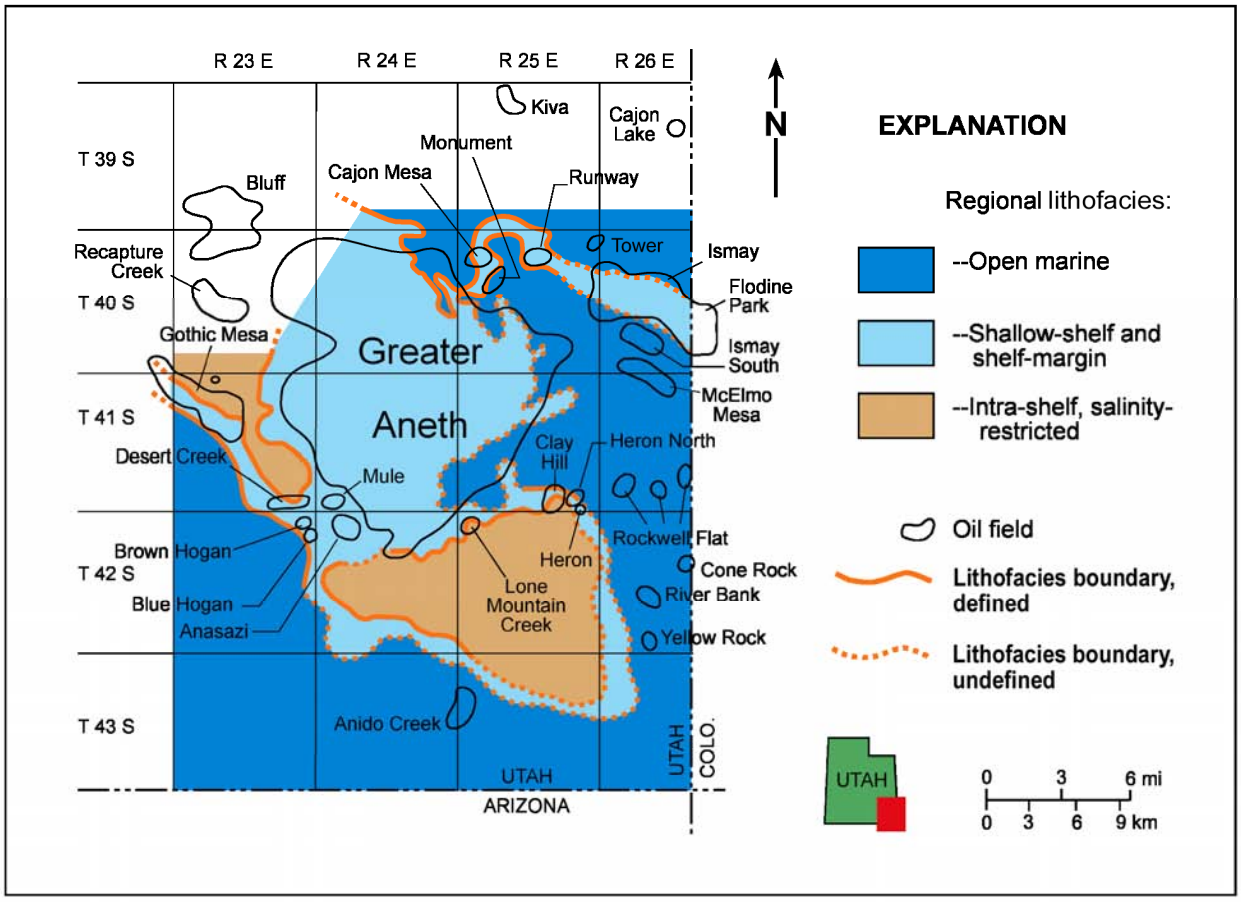


Figure 10-10. Map of major depositional environments/lithofacies for the Aneth platform Desert Creek zone subplay. After Chidsey and others (1996c).

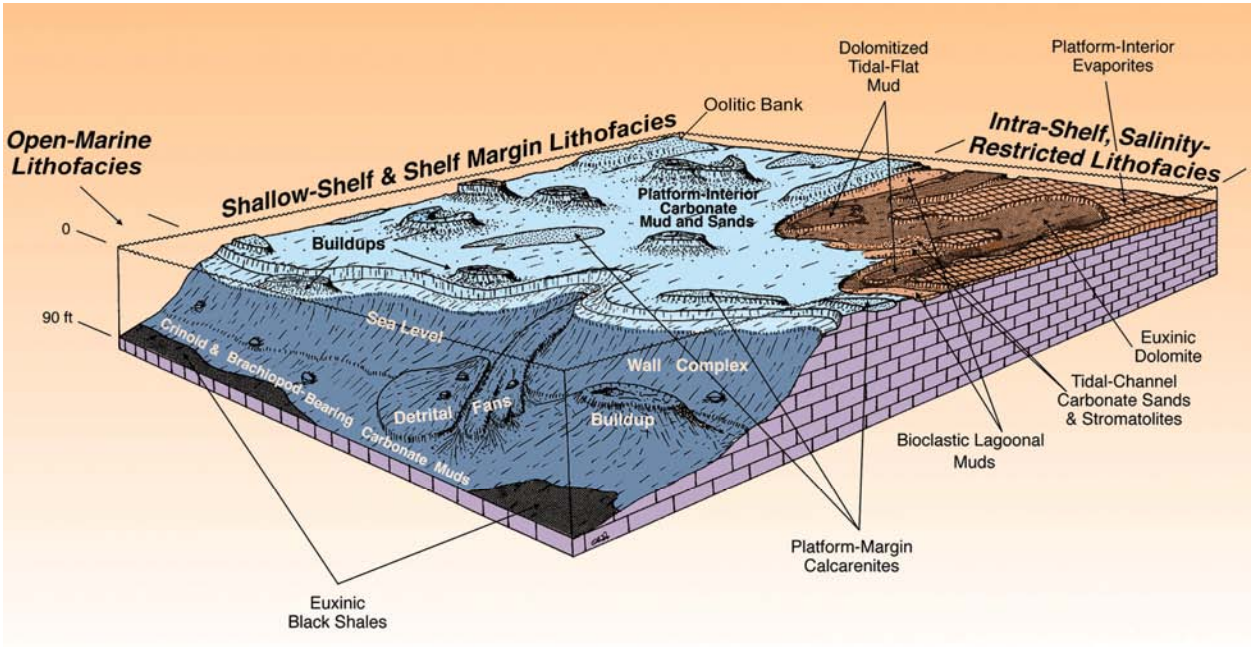


Figure 10-11. Block diagram displaying depositional environments within the Aneth platform Desert Creek zone subplay. After Chidsey and others (1996c).

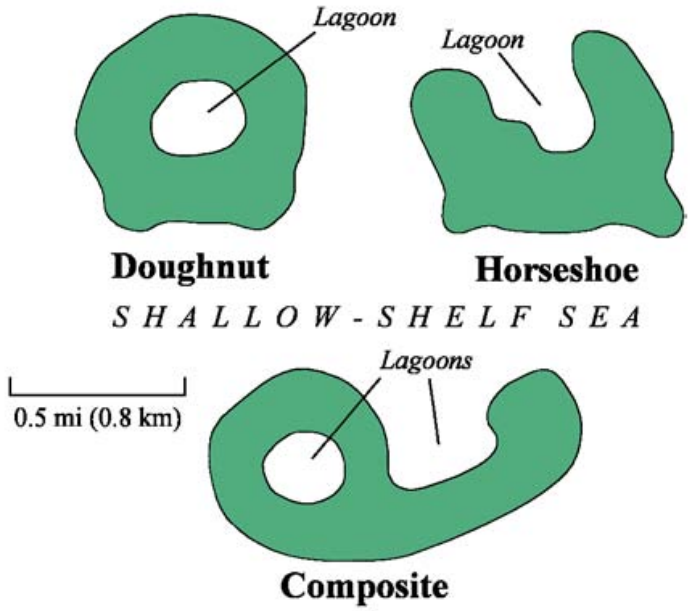


Figure 10-12. Map view of typical carbonate buildup shapes (most often phylloid algal in composition) on the shallow carbonate shelf during Desert Creek time. After Chidsey and others (1996c).

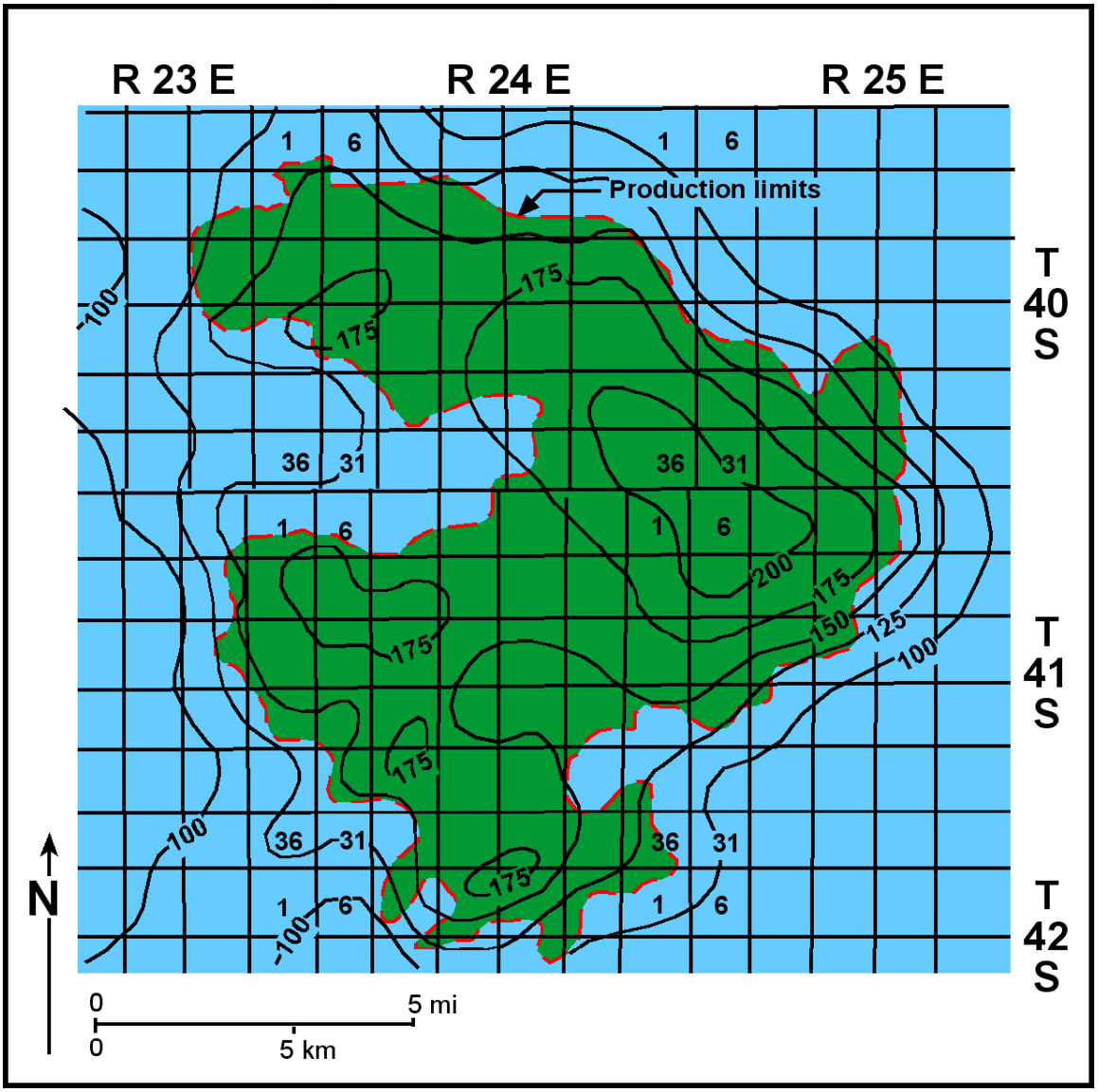


Figure 10-13. Generalized thickness map of the Desert Creek zone, Greater Aneth field, San Juan County, Utah; contour interval = 25 feet. Modified from Peterson and Ohlen (1963).

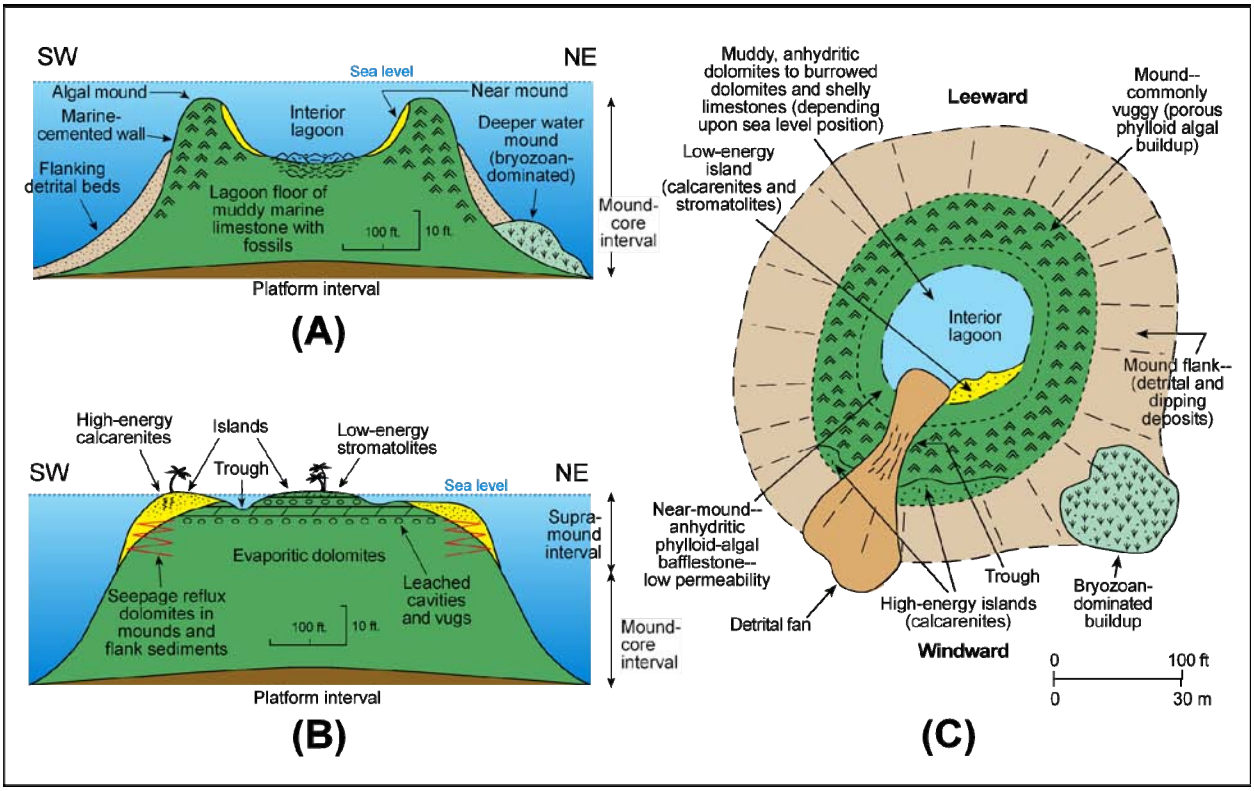


Figure 10-14. Detailed environmental setting of Desert Creek algal buildup features surrounding the Greater Aneth field. (A) Cross section during sea-level highstands when the mound was actively growing. (B) Cross section during sea-level lowstands when the mound experienced porosity modification, erosion of the mound margins, evaporite dolomites filled in the lagoon, and troughs (tidal channels) and islands developed on the top. (C) Map view of idealized algal buildup. After Chidsey and others (1996).

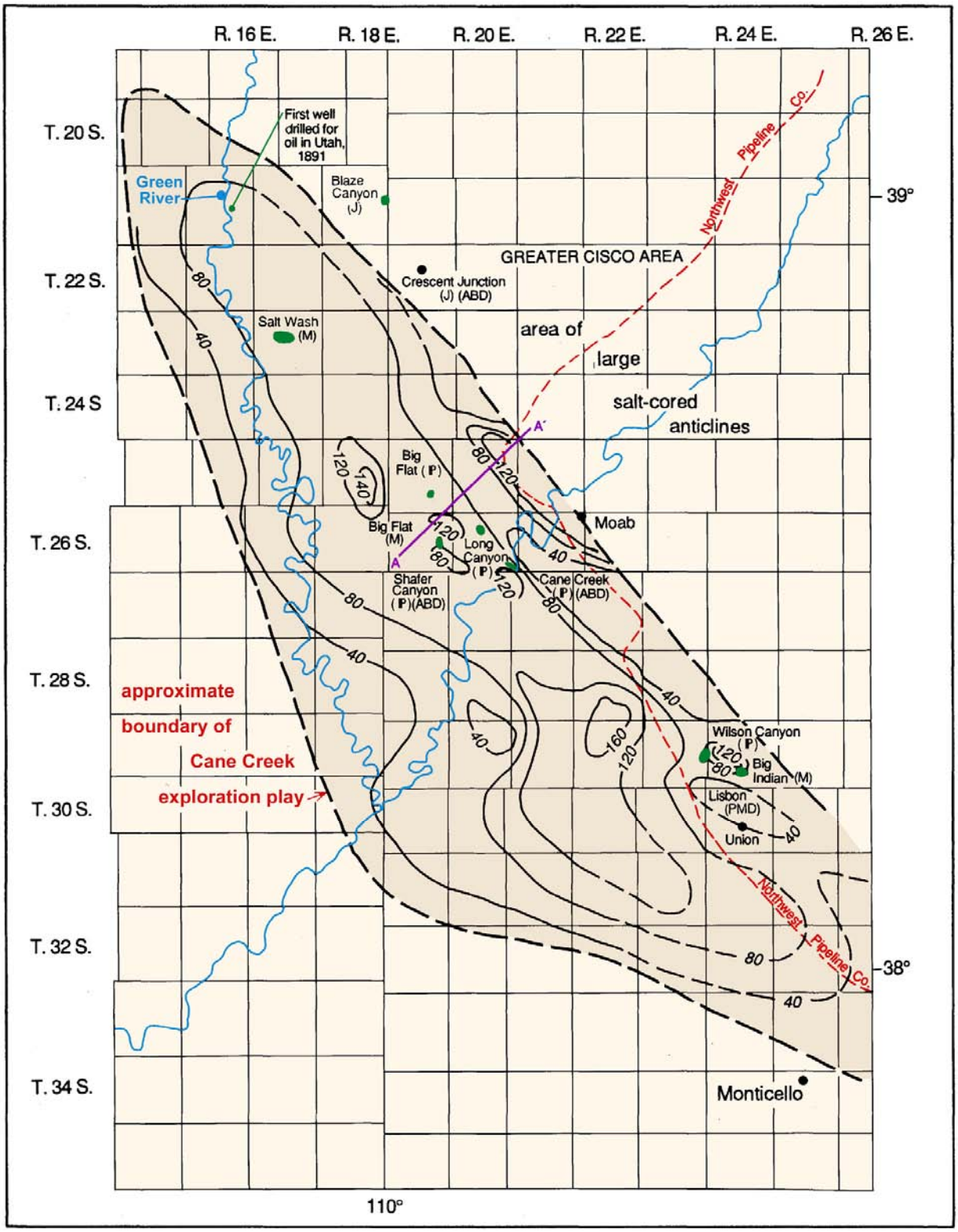


Figure 10-15. Generalized thickness map of the Cane Creek shale of the Paradox Formation. The shale onlaps to the west and southwest. Thickness of the Cane Creek shale in the area of large salt-cored anticlines is unknown. Local thickness varies due to salt flowages over anticlines and fault blocks.

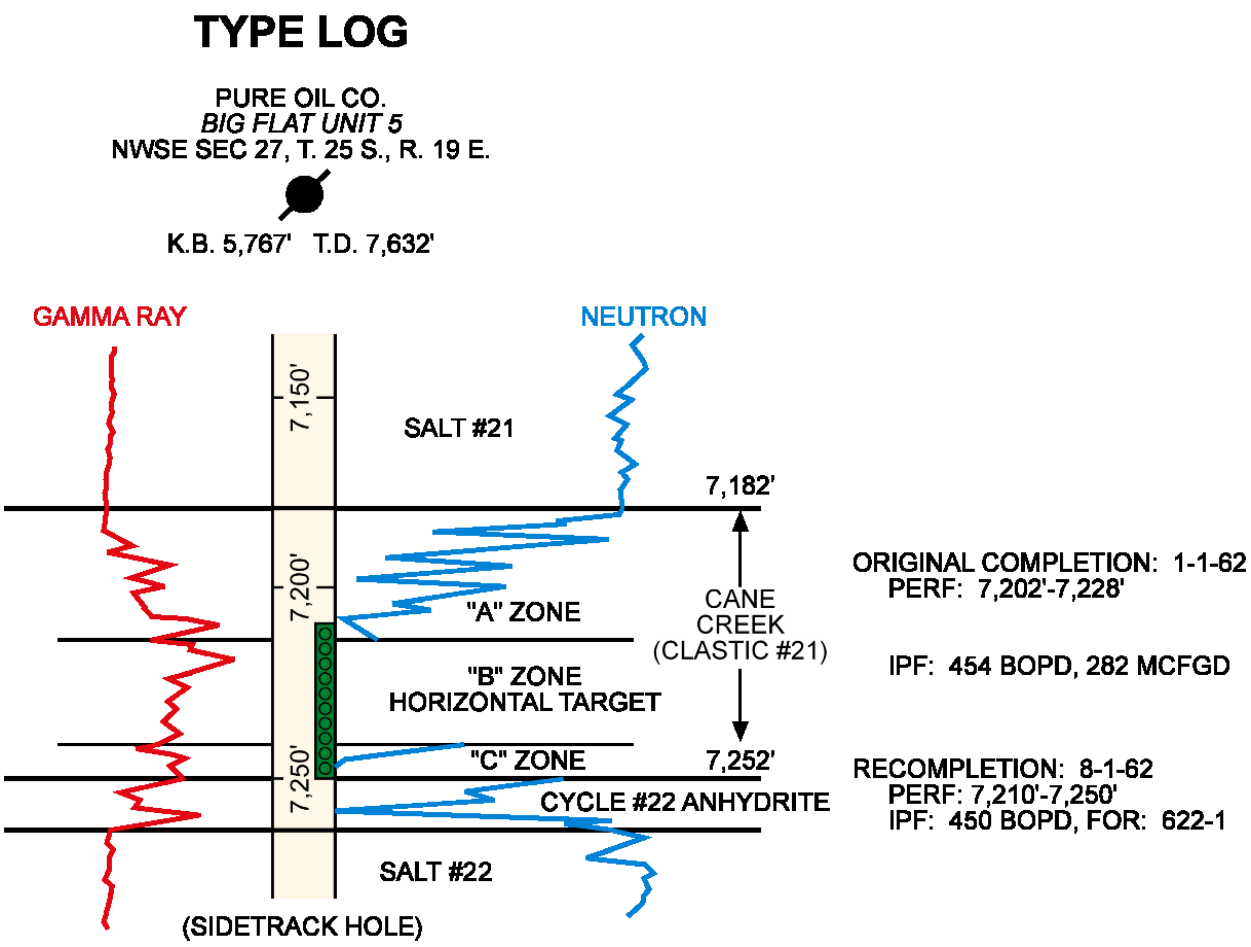


Figure 10-16. Log section of the Cane Creek shale of the Paradox Formation from the Big Flat No. 5 well. The Cane Creek is divided into zones A, B, and C. The B zone is the primary fractured oil reservoir. After Grove and others, 1993.

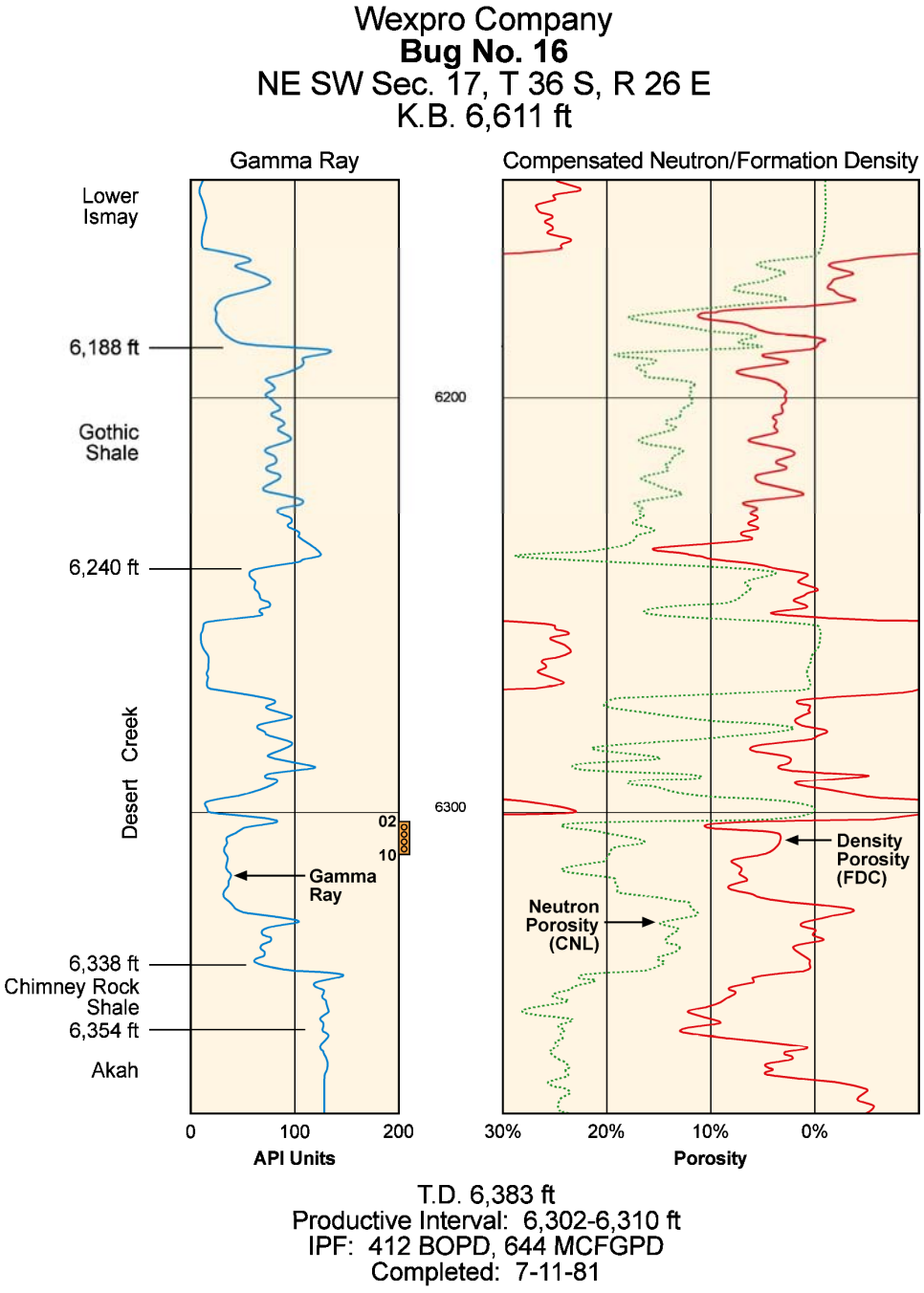


Figure 10-17. Typical gamma ray-compensated neutron/formation density log for the Desert Creek zone in the Blanding sub-basin, from the Bug No. 16 well (section 17, T. 36 S., R. 26 E., Salt Lake Base Line and Meridian [SLBL&M]), Bug field, San Juan County, Utah. Producing (perforated) interval between depths of 6302 and 6310 feet. See figure 10-4 for location of Bug field.

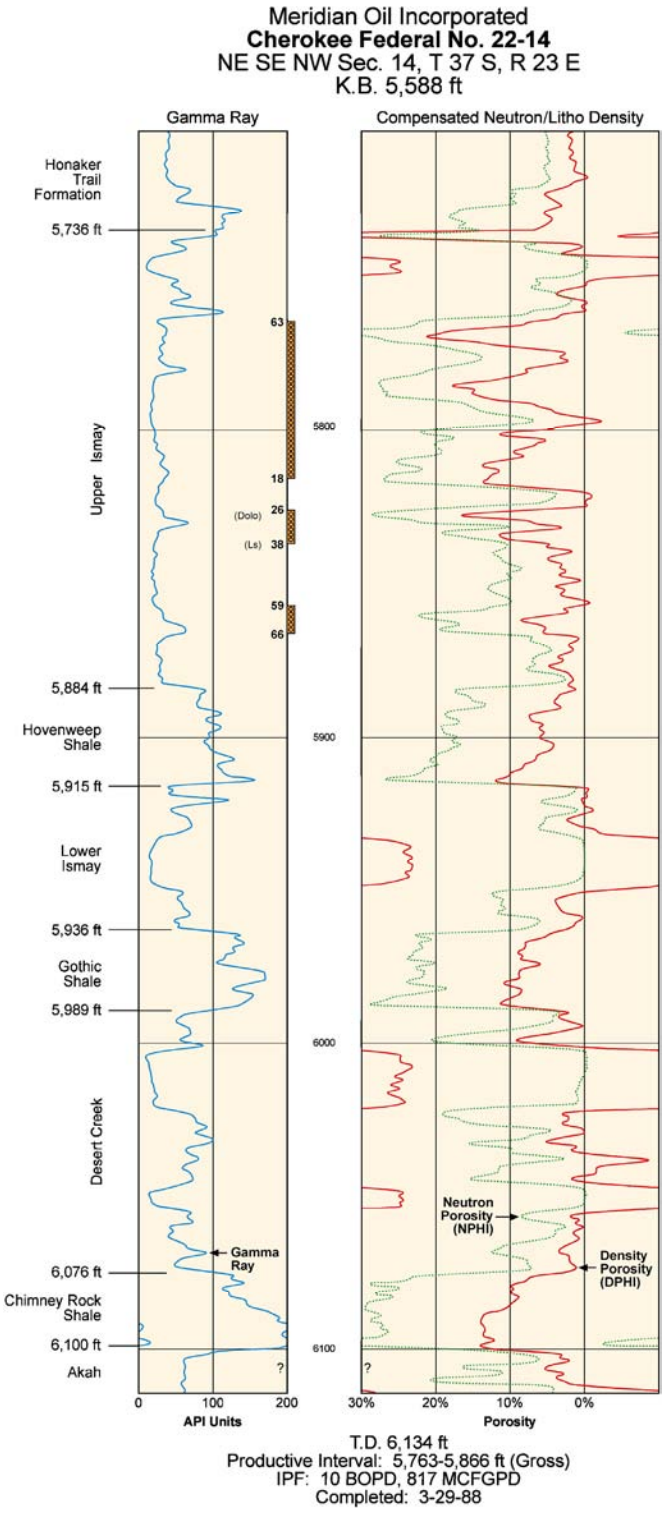


Figure 10-18. Typical gamma ray-compensated neutron/litho density log for the Ismay zone in the Blanding sub-basin, from the Cherokee Federal No. 22-14 well (section 14, T. 37 S., R. 23 E., SLBL&M), Cherokee field, San Juan County, Utah. Producing (perforated) interval between depths of 5763 and 5866 feet. See figure 10-4 for location of Cherokee field.

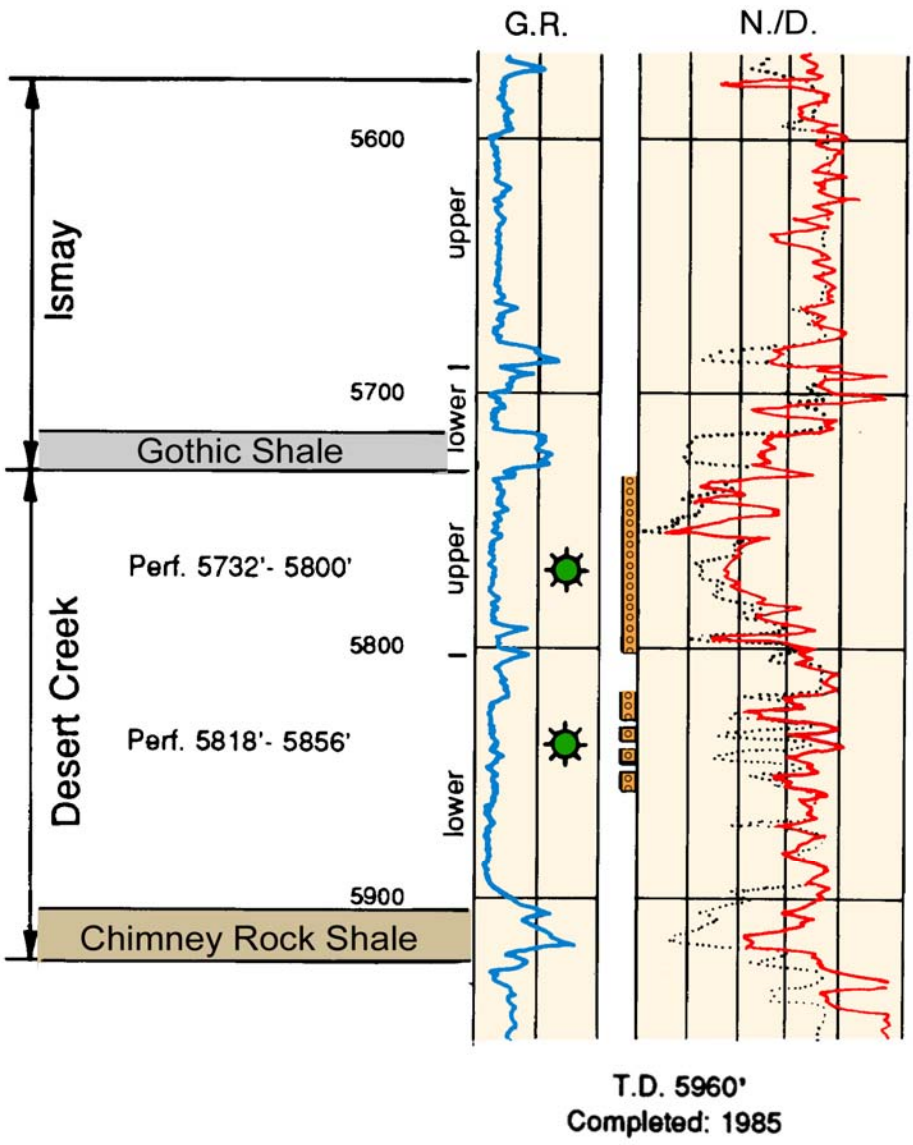


Figure 10-19. Typical gamma ray-compensated neutron/density log for the Desert Creek zone in the Aneth platform, from the White Mesa No. 33-44 well (section 34, T. 41 S., R. 24 E., SLBL&M), Greater Aneth field, San Juan County, Utah. Producing (perforated) interval between depths of 5732 and 5856 feet. See figure 10-4 for location of Greater Aneth field.

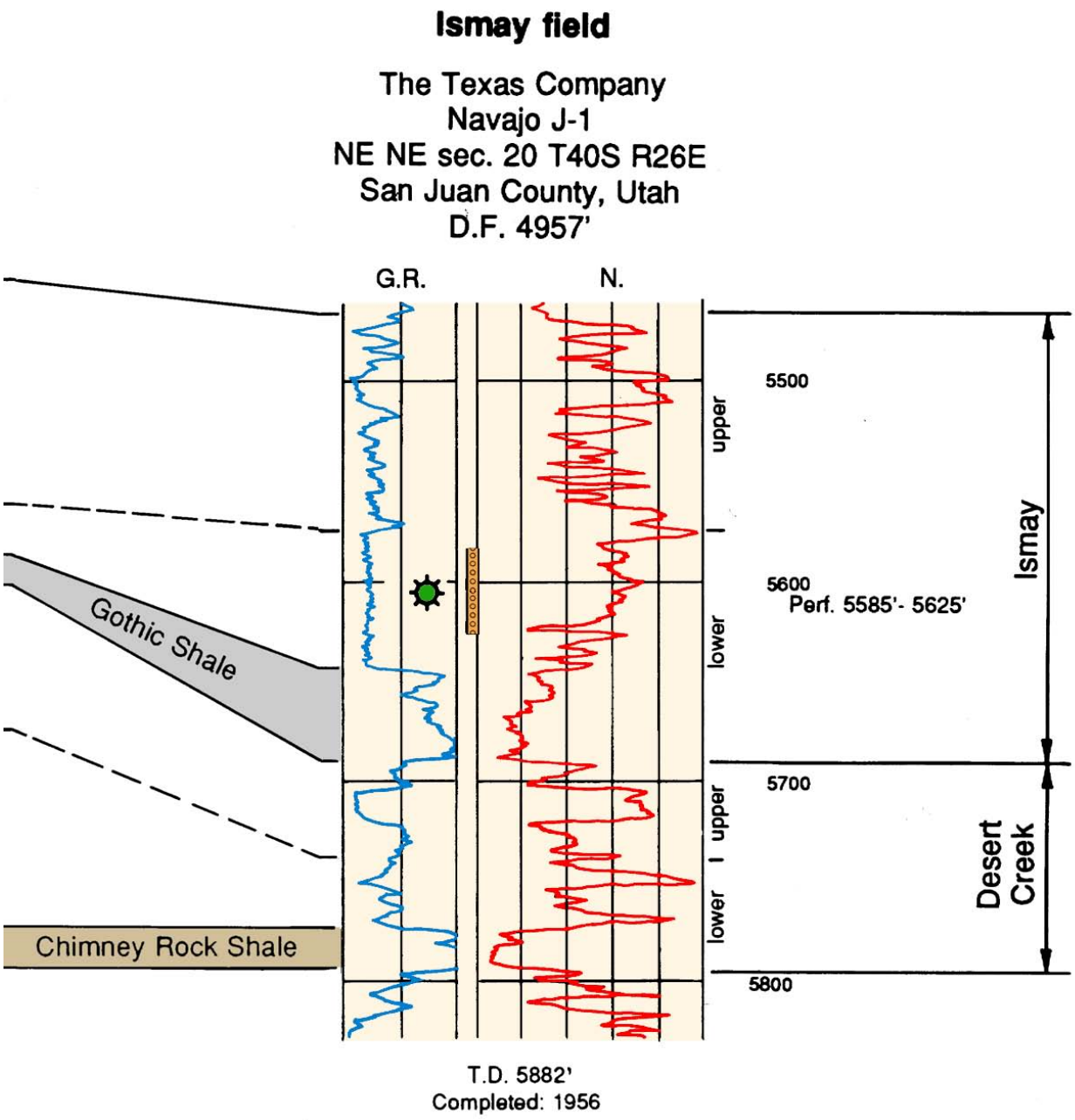


Figure 10-20. Typical gamma ray-compensated neutron log for the Ismay zone in the Aneth platform, from the Navajo No. J-1 well, Ismay field (section 20, T. 40 S., R. 26 E., SLBL&M), San Juan County, Utah. Producing (perforated) interval between depths of 5585 and 5625 feet. See figure 10-4 for location of Ismay field.

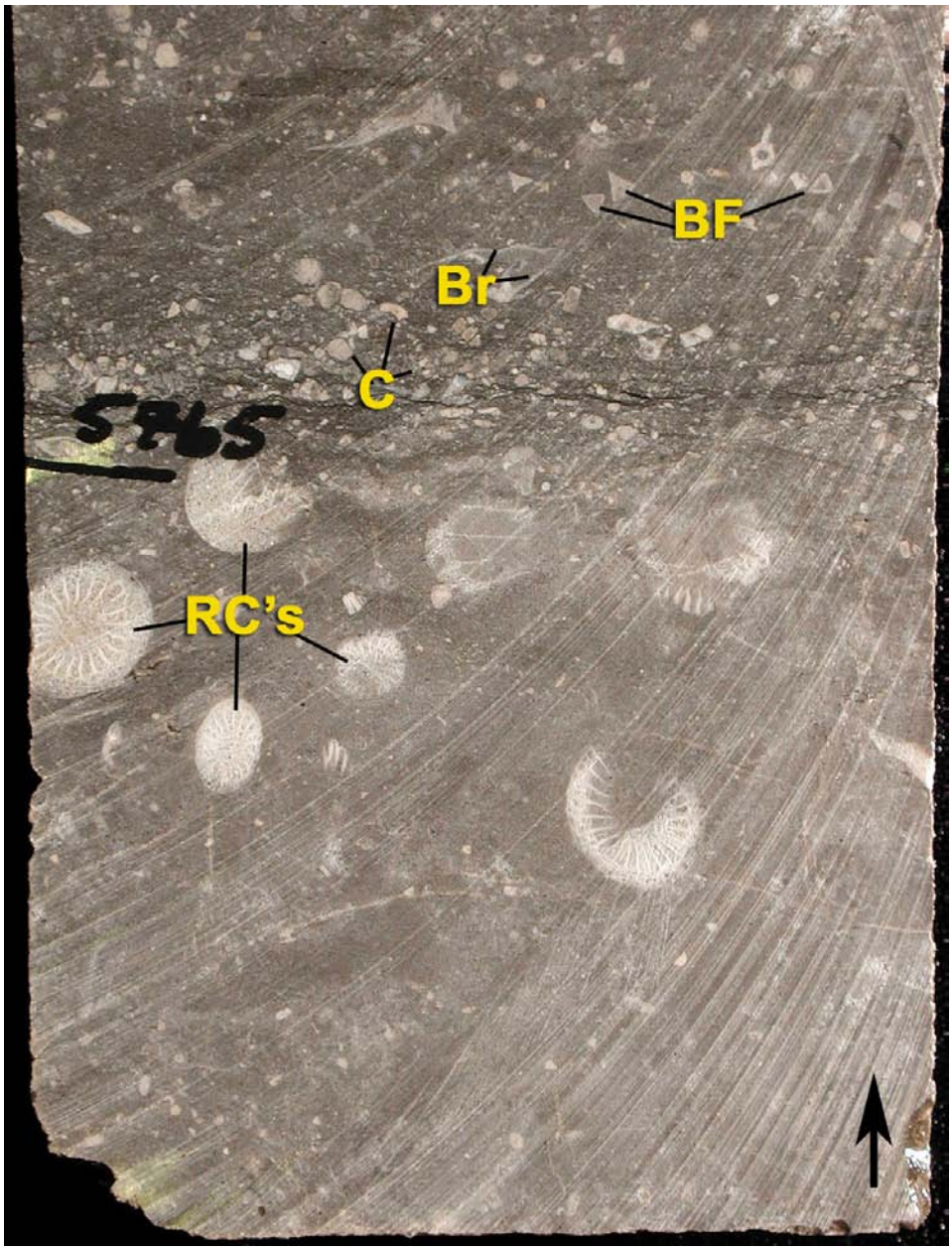


Figure 10-21. Typical Ismay-zone open-marine lithofacies showing well-preserved rugose corals (RC), crinoids (C), brachiopods (Br), and benthic forams (BF); No. 1-28 Cuthair wildcat well (section 28, T. 38 S., R. 22 E., SLBL&M), San Juan County, Utah, slabbed core from 5765 feet.

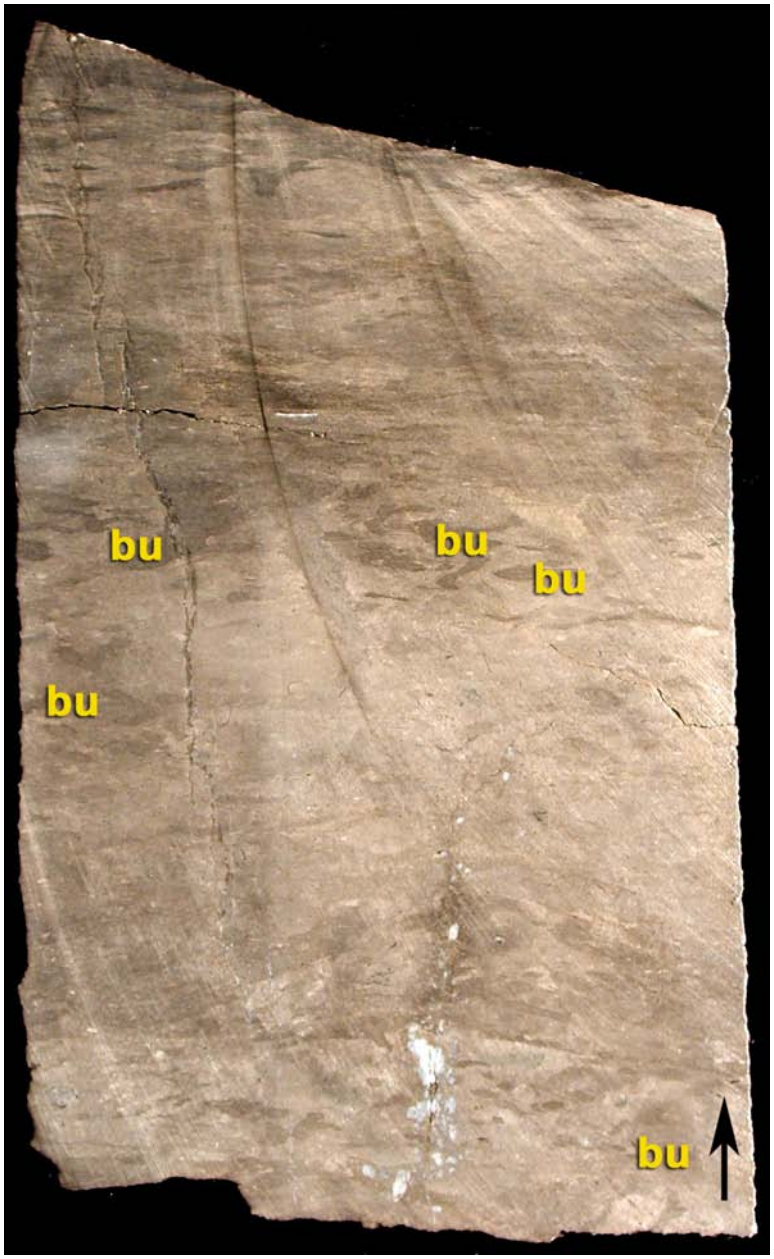


Figure 10-22. Typical Ismay-zone middle-shelf lithofacies showing bioturbated lime mudstone containing compacted sub-horizontal feeding burrows (bu); Tank Canyon No. 1-9 wildcat well (section 9, T. 37 S., R. 24 E., SLBL&M), San Juan County, Utah, slabbed core from 5412.5 feet.

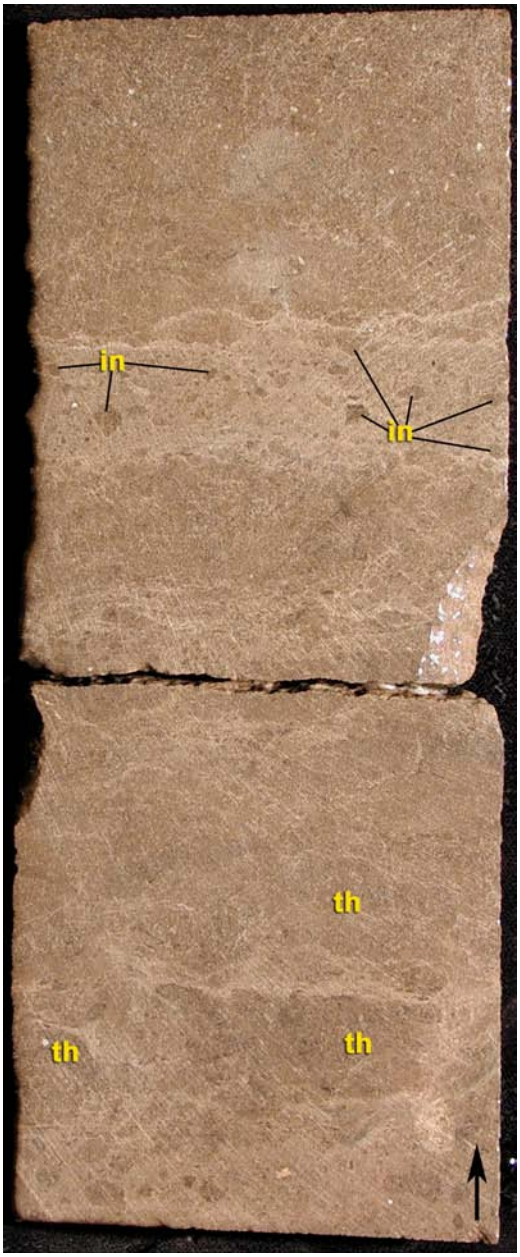


Figure 10-23. Typical Ismay-zone inner shelf/tidal flat lithofacies showing dolomitized lumpy microbial structures resembling small thrombolites (th) and intraclasts (in) composed of desiccated and redeposited thrombolitic fragments; Tin Cup Mesa No. 2-23 well (section 23, T. 38 S., R. 25 E., SLBL&M), Tin Cup Mesa field, San Juan County, Utah, slabbed core from 5460.5 feet.

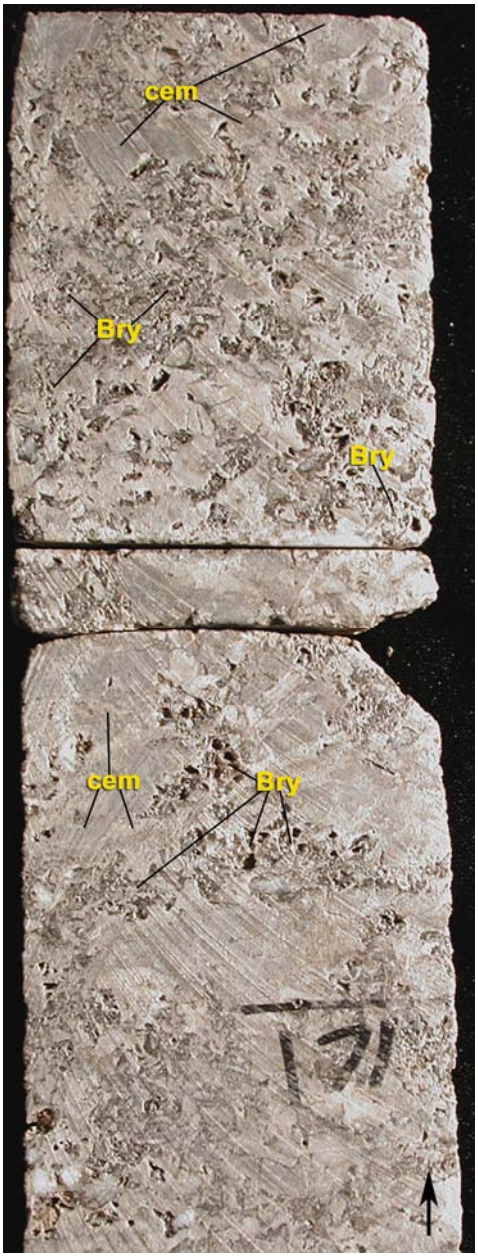


Figure 10-24. Typical Ismay-zone bryozoan-mound lithofacies showing large tubular bryozoans (Bry) and "lumps" of marine cement (cem). Scattered phylloid-algal plates are also present. This mound fabric is typical of higher energy, and possibly shallower water than the mud-dominated fabrics. Mustang No. 3 well (section 26, T. 36 S., R. 25 E., SLBL&M), Mustang Flat field, San Juan County, Utah, slabbed core from 6171 feet.

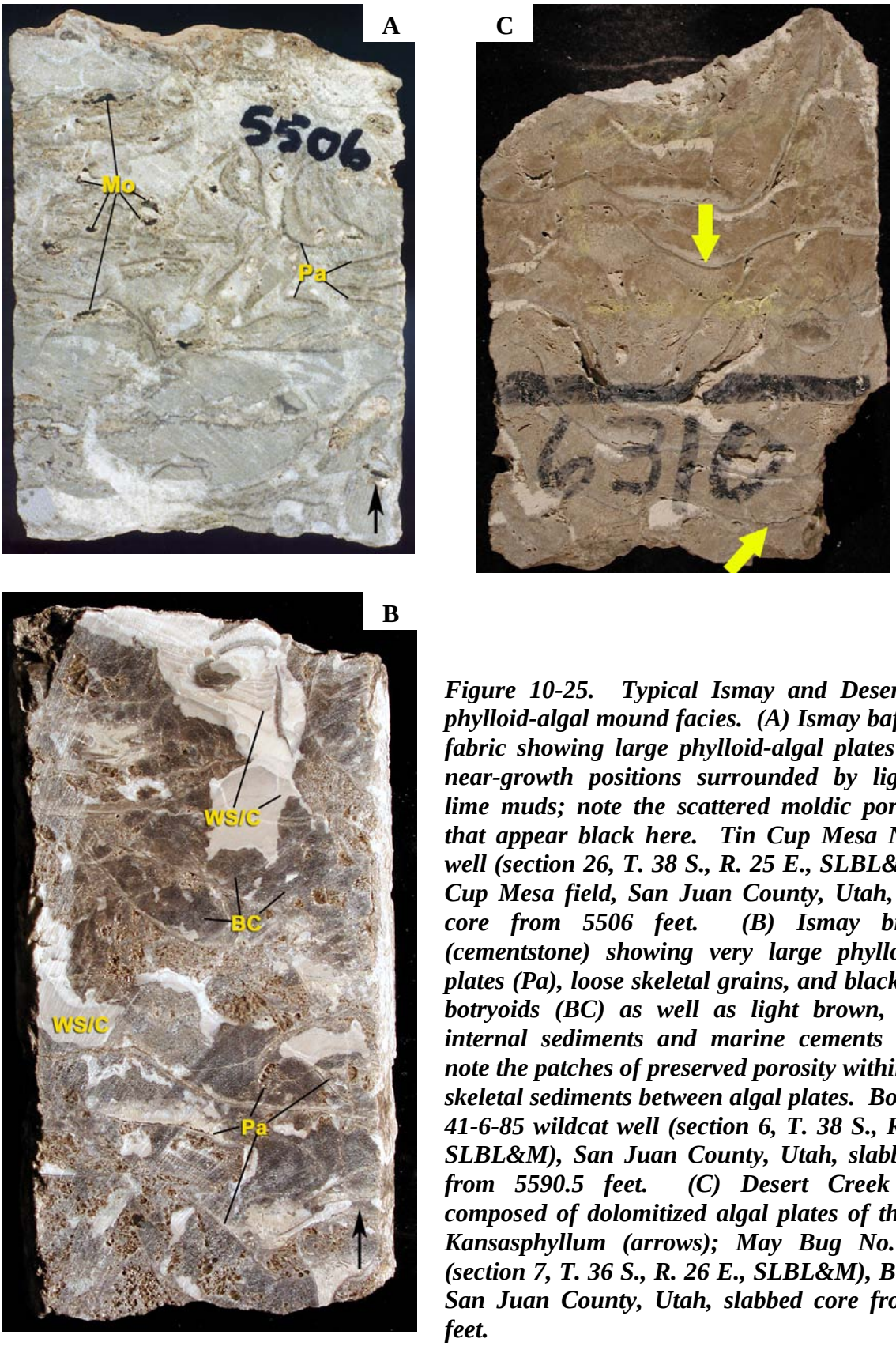


Figure 10-25. Typical Ismay and Desert Creek phylloid-algal mound facies. (A) Ismay bafflestone fabric showing large phylloid-algal plates (Pa) in near-growth positions surrounded by light gray lime muds; note the scattered moldic pores (Mo) that appear black here. Tin Cup Mesa No. 3-26 well (section 26, T. 38 S., R. 25 E., SLBL&M), Tin Cup Mesa field, San Juan County, Utah, slabbed core from 5506 feet. (B) Ismay bindstone (cementstone) showing very large phylloid-algal plates (Pa), loose skeletal grains, and black marine botryoids (BC) as well as light brown, banded, internal sediments and marine cements (WS/C); note the patches of preserved porosity within coarse skeletal sediments between algal plates. Bonito No. 41-6-85 wildcat well (section 6, T. 38 S., R. 25 E., SLBL&M), San Juan County, Utah, slabbed core from 5590.5 feet. (C) Desert Creek mound composed of dolomitized algal plates of the genus Kansasphyllum (arrows); May Bug No. 2 well (section 7, T. 36 S., R. 26 E., SLBL&M), Bug field, San Juan County, Utah, slabbed core from 6310 feet.

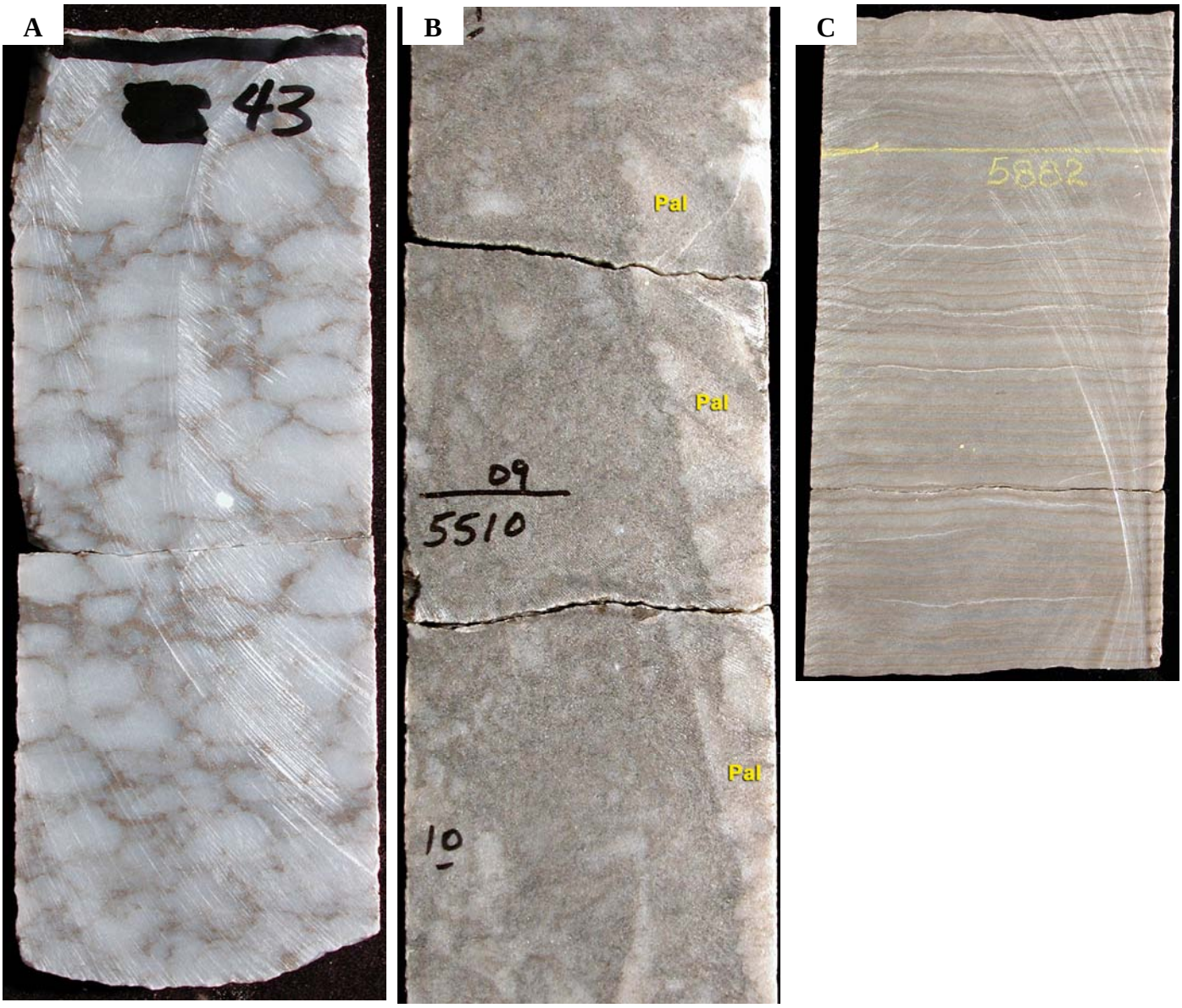


Figure 10-26. Anhydrite growth forms typically found in anhydrite salina facies of upper Ismay intra-shelf basins. (A) Nodular-mosaic ("chicken-wire") anhydrite; Tank Canyon No. 1-9 wildcat well (section 9, T. 37 S., R. 24 E. SLBL&M), San Juan County, Utah, slabbed core from 5343 feet. (B) Large palmate crystals of anhydrite (Pal) along the right margin of this core segment probably grew in a gypsum aggregate that resembled an inverted candelabra while the remainder of the core segment consists of detrital and chemical anhydrite that filled in the relief around the palmate structure; Sioux Federal No. 30-1 wildcat well (section 30, T. 38 S., R. 25 E., SLBL&M), San Juan County, Utah, slabbed core from 5510 feet. (C) Thin (cm-scale), banded couplets of pure anhydrite (white to light gray) and dolomitic anhydrite (brown); Montezuma No. 41-17-74 wildcat well (section 17, T. 37 S., R. 24 E., SLBL&M), San Juan County, Utah, slabbed core from 5882 feet.



Figure 10-27. Typical Desert Creek-zone dolomitized grainstone, calcarenite lithofacies; North Heron No. 35-C well (section 35, T. 41 S., R. 25 E., SLBL&M), Heron field, San Juan County, Utah, slabbed core from 5589 feet.



Figure 10-28. Typical Desert Creek-zone oolitic grainstone; Aneth No. 27-D-4 well (section 27, T. 40 S., R. 24 E., SLBL&M), Greater Aneth field, San Juan County, Utah, slabbed core from 5620 feet. Note excellent moldic porosity development.

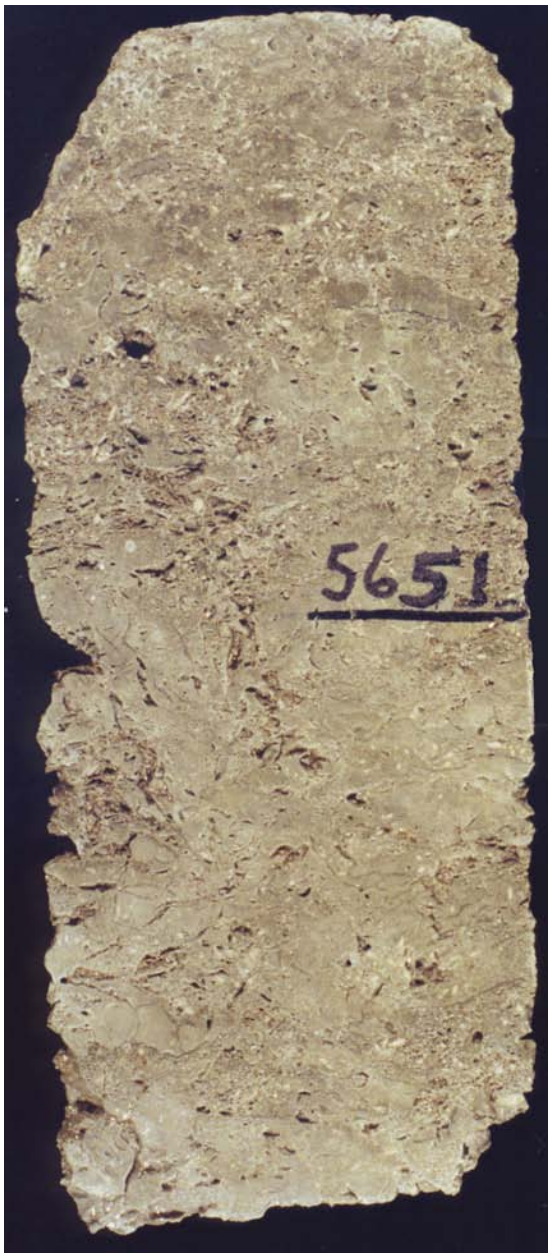


Figure 10-29. Typical highly productive Desert Creek-zone phylloid-algal plate bafflestone; Anasazi No. 1 well (section 5, T. 42 S., R. 24 E., SLBL&M), Greater Aneth field, San Juan County, Utah, slabbed core from 5651 feet. Note good visual shelter porosity.

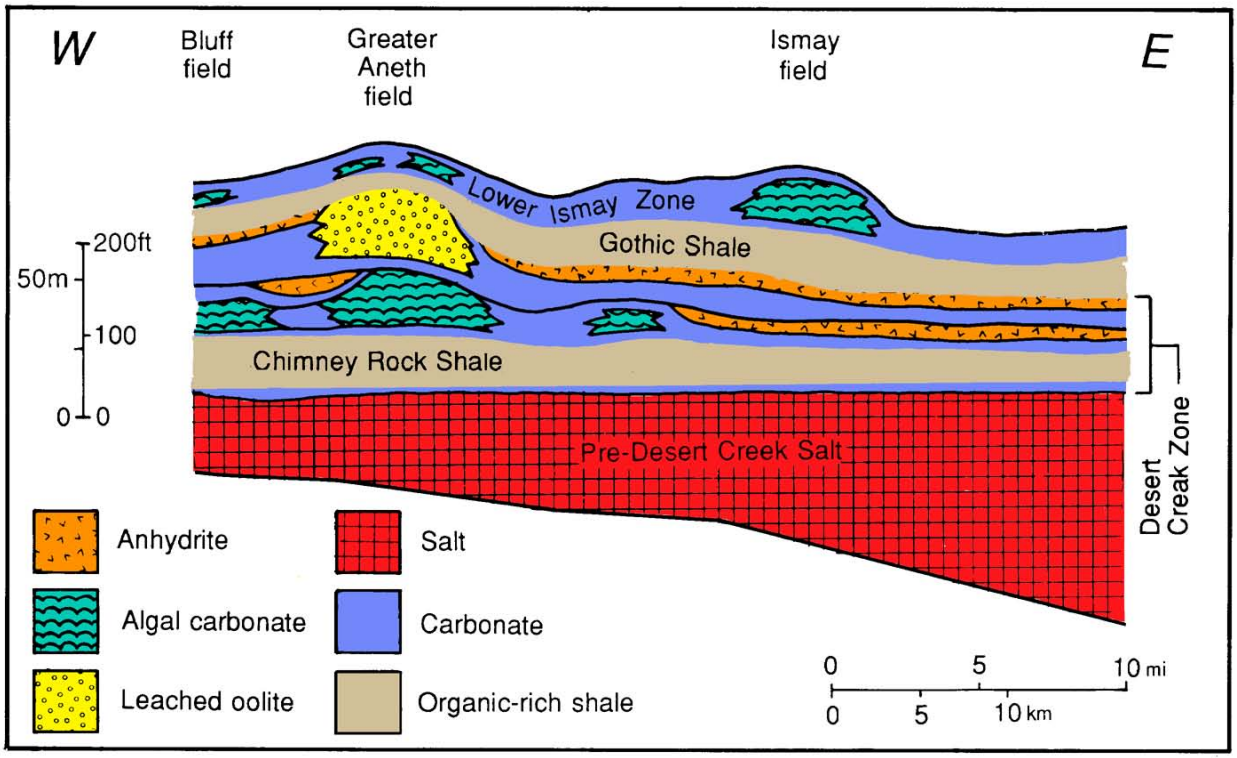


Figure 10-30. Diagrammatic lithofacies cross section, Greater Aneth field, southeastern Utah. Datum is base of the Desert Creek zone of the Paradox Formation. Modified from Peterson (1992).

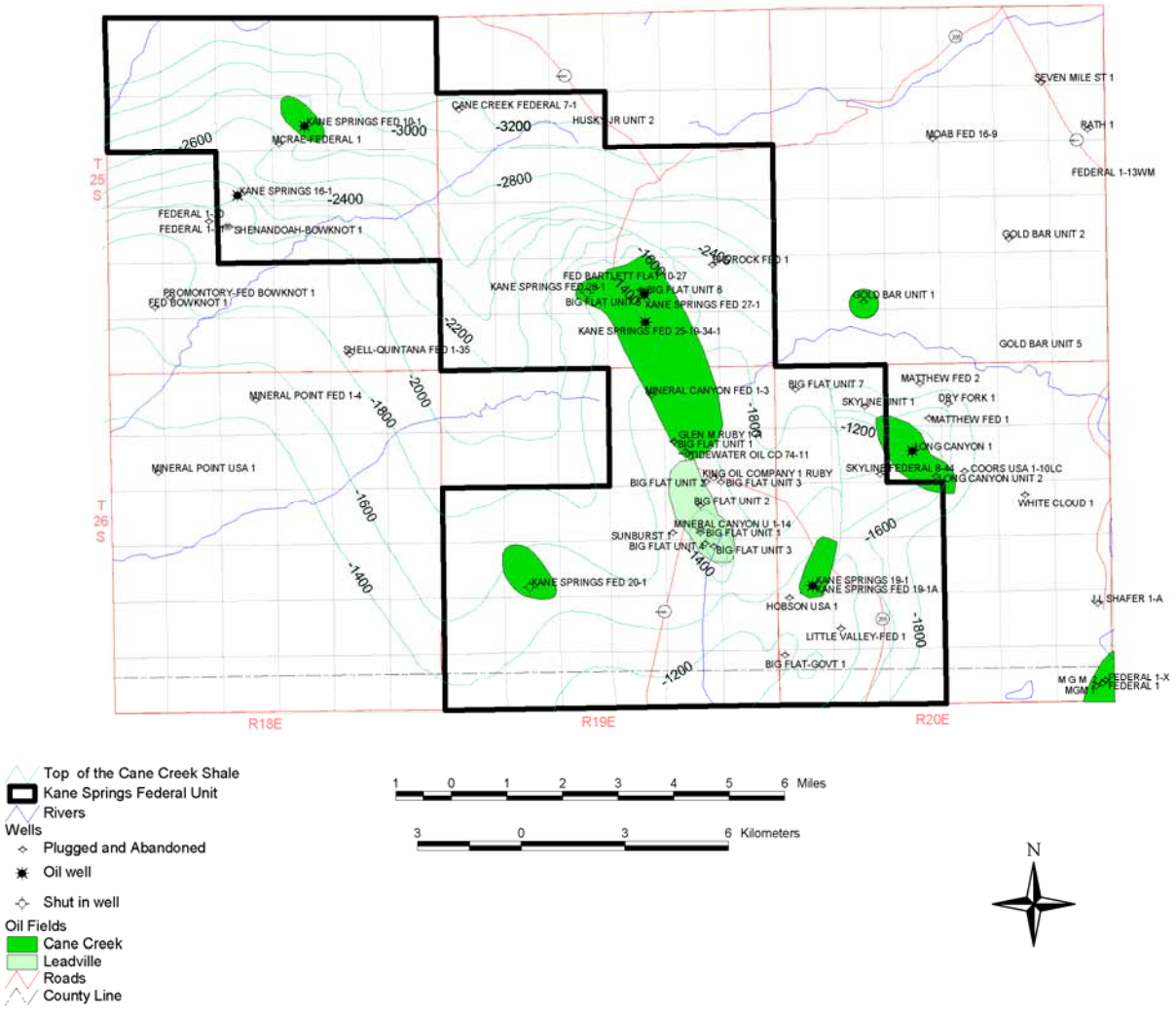
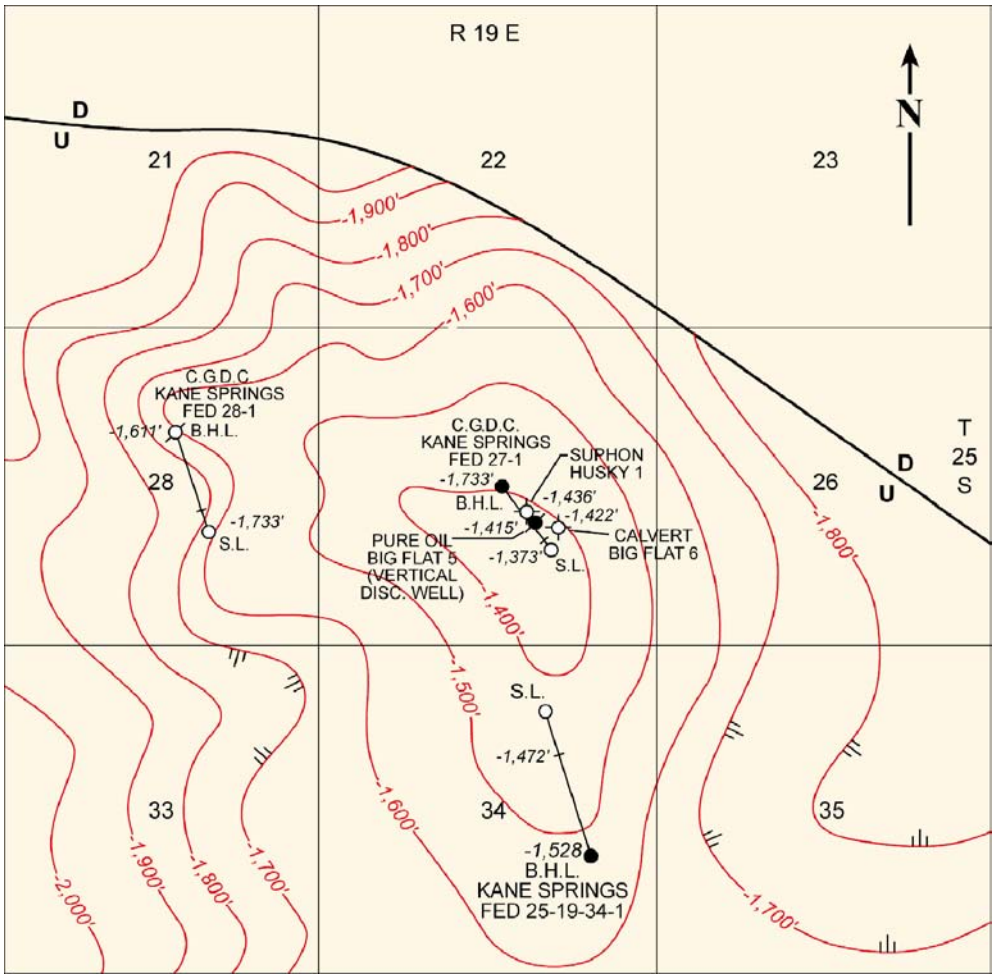


Figure 10-31. Map of the Kane Springs Federal exploratory unit. Structure contours on the top of the Cane Creek shale. Contour interval = 200 feet; datum = sea level.



BIG FLAT FIELD
GRAND COUNTY, UTAH
CANE CREEK STRUCTURE
Contour interval 100 feet
Sea level elevation

EXPLANATION

- DRY HOLE
- PRODUCING OIL WELL
- ABANDONED OIL WELL
- TEMPORARY ABN'D. WELL

HORIZONTAL WELL
-1,439' B.H.L. BOTTOM HOLE LOCATION
CANE CREEK TOP @ B.H.L.
CANE CREEK INTERCEPT
-1,373'
CANE CREEK TOP @ INTERCEPT
S.L. SURFACE LOC.

0 5,000 Ft
0 1,000 M

Figure 10-32. Map of Big Flat field showing the original vertical discovery well, the Big Flat No. 5, and the first horizontal discovery, the Kane Springs No. 27-1 well. Structure contours on top of the Cane Creek shale. Contour interval = 100 feet; datum = sea level.

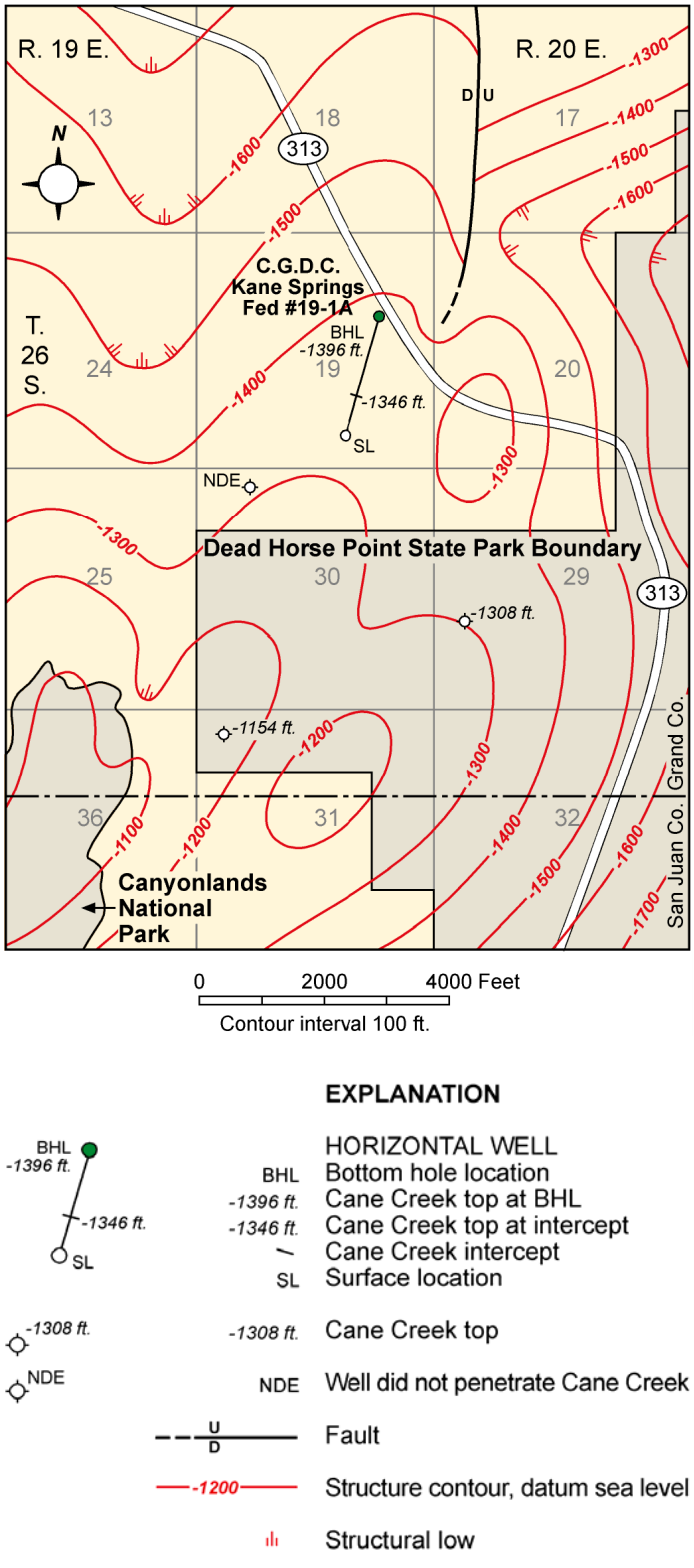


Figure 10-33. Cane Creek shale structure map, Park Road oil field, Grand County. Surface location, direction, and length of horizontal well shown (after Grove and others, 1993). See figure 10-1 for location of Park Road field.

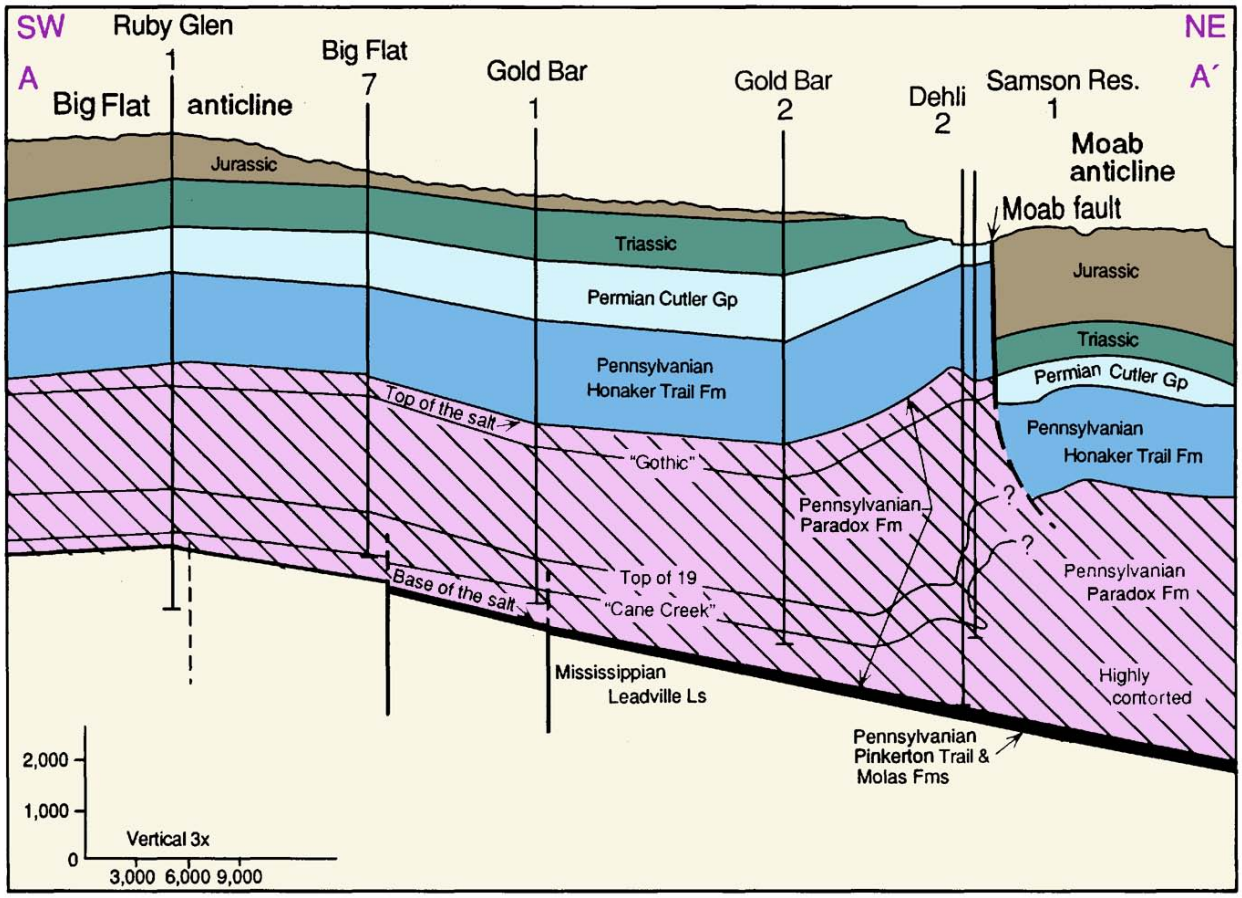


Figure 10-34. Cross section, A – A', from the Moab anticline to the Big Flat anticline. Location of cross section is shown in figure 10-3. The interbeds in the Paradox are organic-rich shales, dolomite, and clastics, that are both source and reservoir for oil. The Cane Creek shale is the most prolific producer and is in the basal portion of the Paradox.

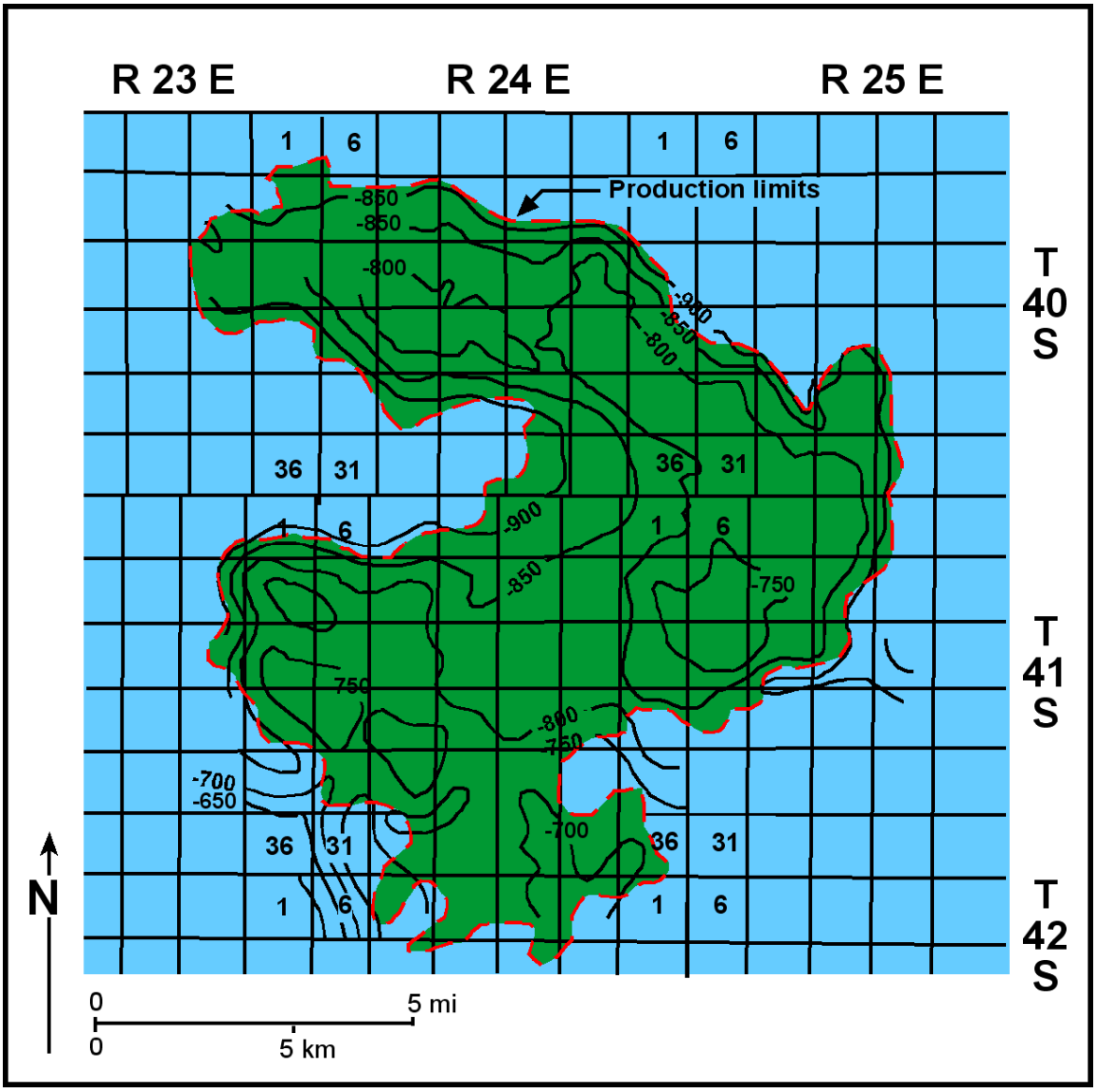


Figure 10-35. Structure contour map of the top of the Desert Creek zone, Greater Aneth field, San Juan County, Utah; contour interval = 50 feet. Modified from Peterson (1992).

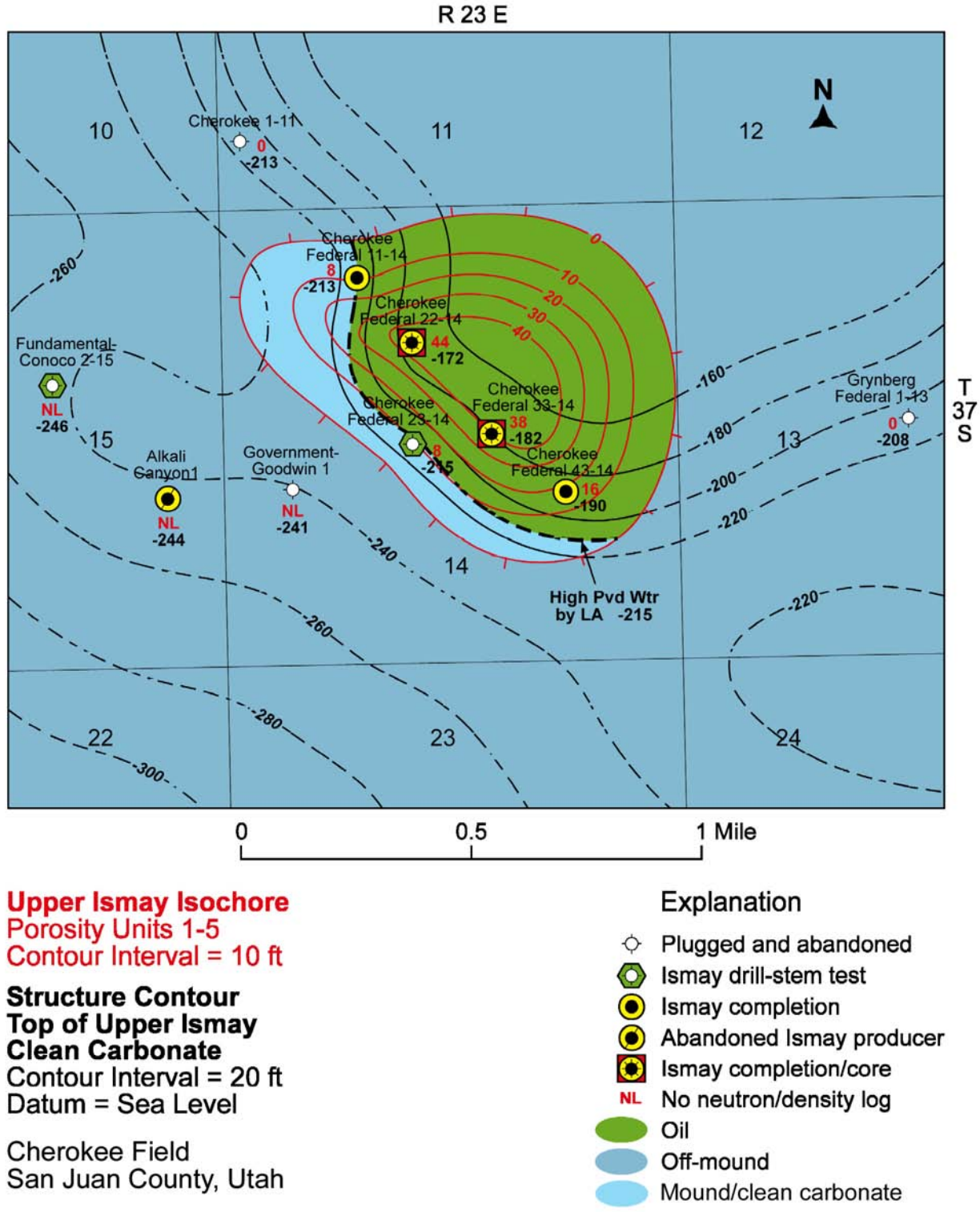


Figure 10-36. Map of combined top of structure and isochore of porosity, upper Ismay-zone mound, Cherokee field, San Juan County, Utah.

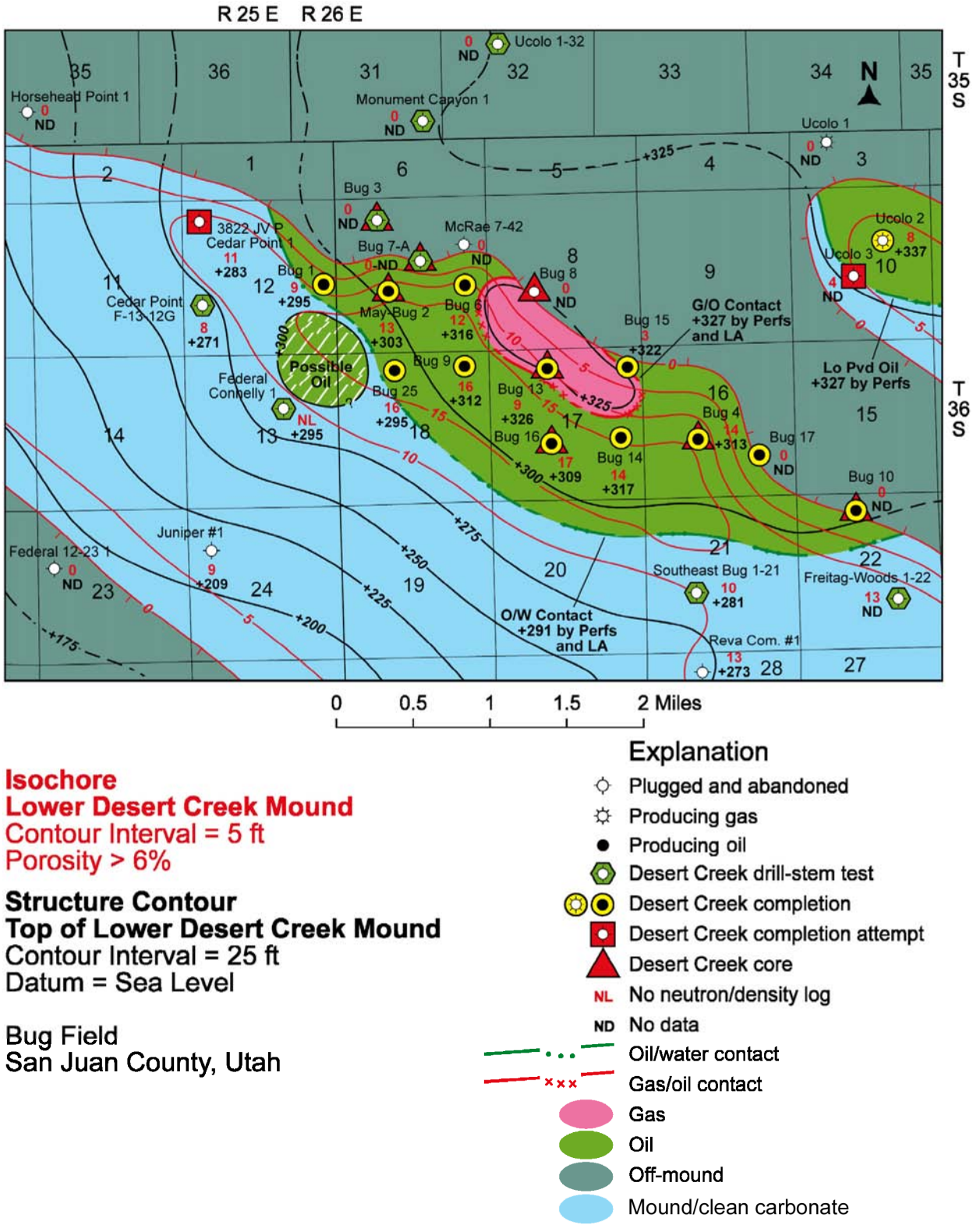


Figure 10-37. Map of combined top of structure and isochore of lower Desert Creek-zone mound, Bug field, San Juan County, Utah.

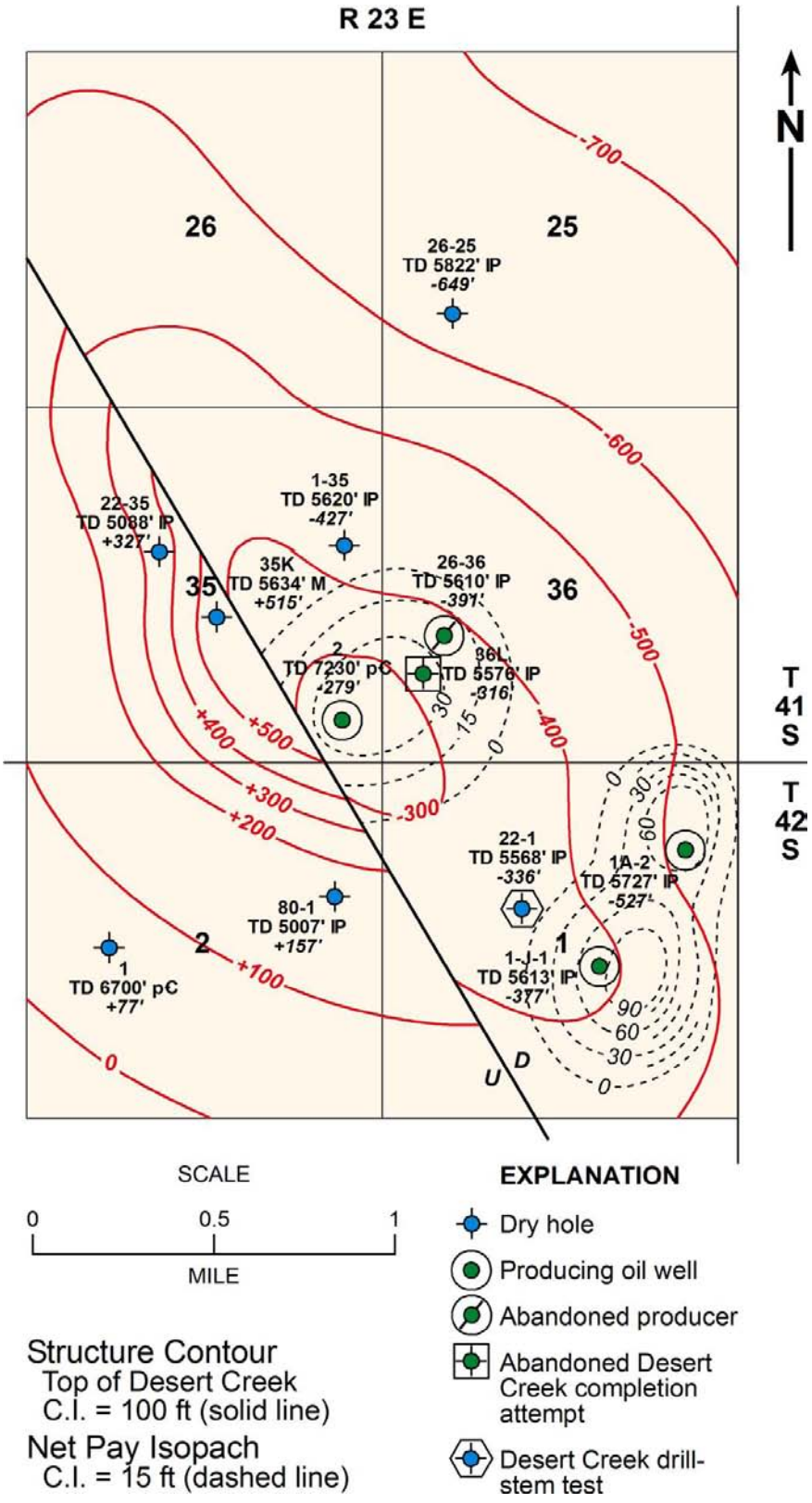


Figure 10-38. Map of combined top of structure and isochore of the Desert Creek-zone mound, Desert Creek field, San Juan County, Utah. Modified from Lauth (1978b).

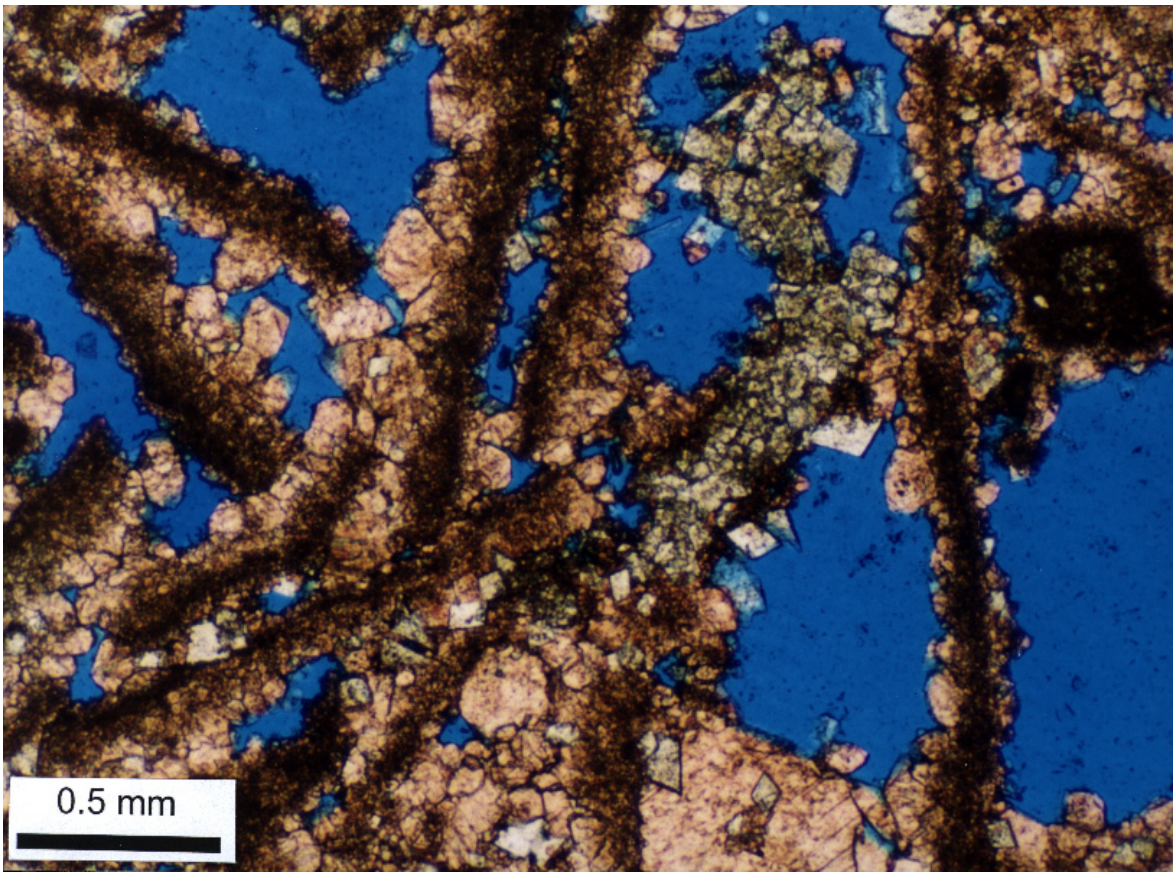


Figure 10-39. Typical Desert Creek-zone primary shelter and early solution porosity within a phylloid-algal bafflestone partially occluded by stubby to equant to dogtooth spar cements of probably meteoric phreatic origin; porosity = 12.5%, permeability 53.8 mD by core-plug analysis. These types of cements have degraded the permeability of these solution-enhanced pore systems. Runway No. 10-C-5A well (section 10, T. 40 S., R. 25 E., SLBL&M), photomicrograph (plane light) from 6127.4 feet, Runway field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

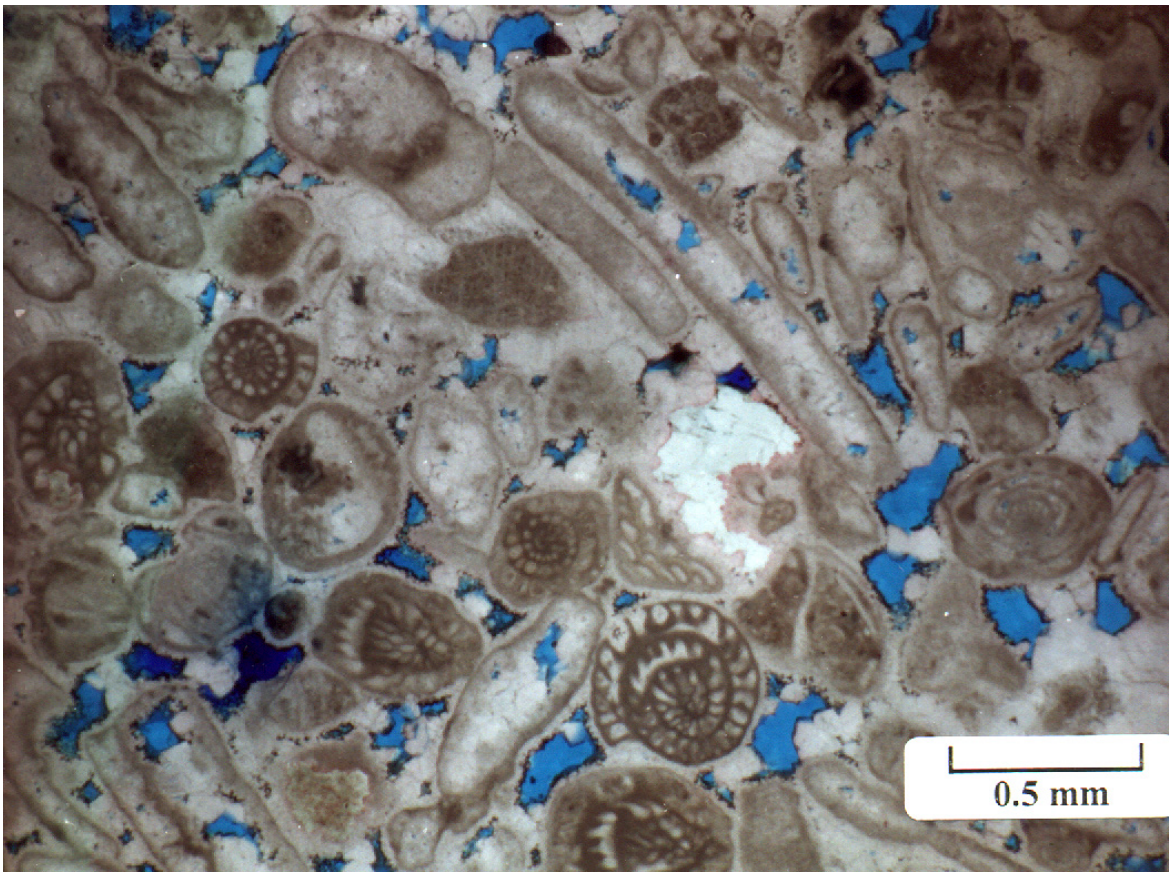


Figure 10-40. Typical Ismay-zone interparticle porosity developed in a high-energy calcarenite skeletal and aggregate grainstone; porosity = 4.6%, permeability = 0.018 mD by core-plug analysis. Among the typical grains of this facies are benthic forams (including fusulinids), phylloid-algal plates, "hard" peloids or micritized skeletal grains, and grain aggregates. The scattered pores (in blue) visible in this image are principally the remnants of primary interparticle space between the skeletal components of this grainstone. Early marine isopachous cements, followed by probable meteoric dogtooth calcite spar and minor anhydrite (in white) have occluded most of the original interparticle porosity. Little Ute No. 1 well (section 11, T. 34 S., R. 20 W.), photomicrograph (plane light with white card technique [diffused light using a piece of paper on the stage of the microscope]) from 5940.5 feet, Little Ute field, Montezuma County, Colorado. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

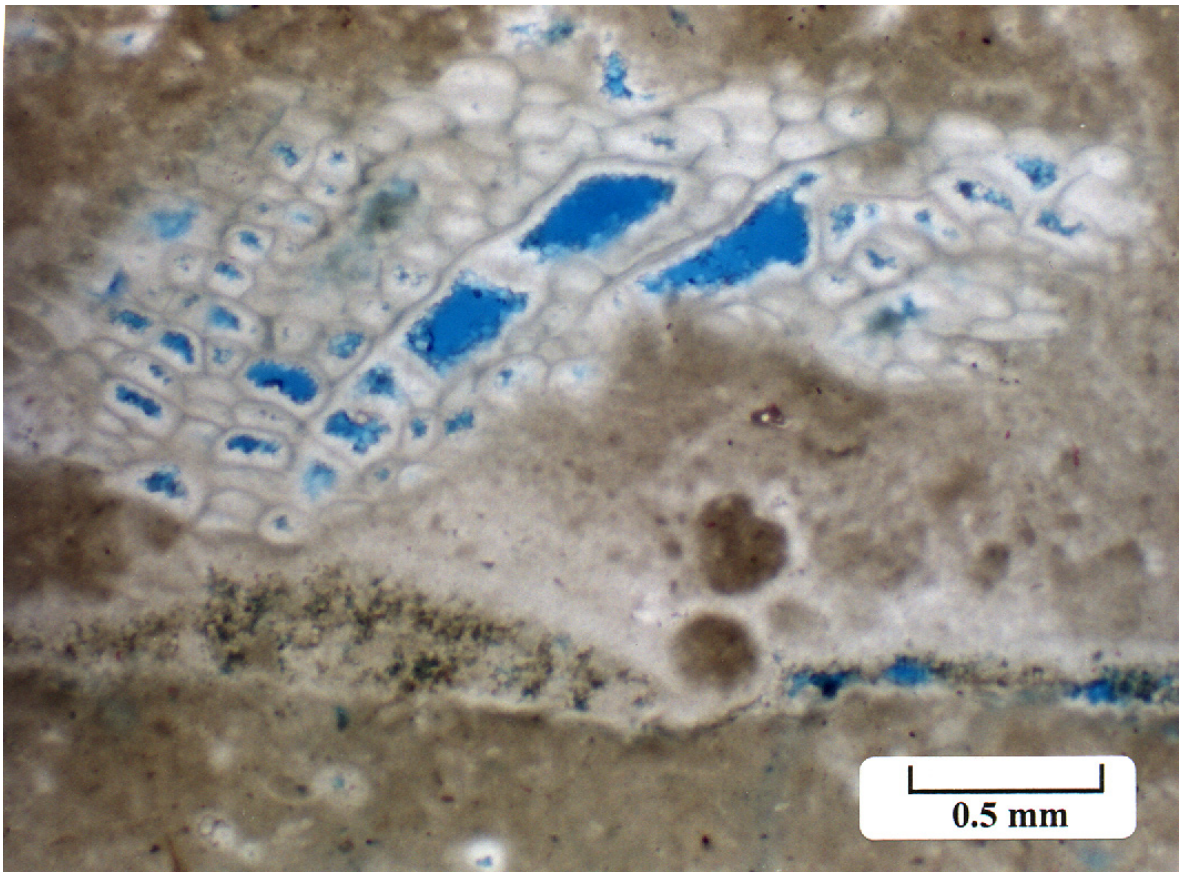


Figure 10-41. Ismay-zone intraparticle porosity; porosity = 9.8%, permeability = 12.2 mD by core-plug analysis. Open pores (in blue) are shown here within the uncemented chambers of encrusting organisms surrounded by lime muds. This sample is from within a phylloid-algal mound core. Little Ute No. 1 well (section 11, T. 34 S., R. 20 W.), photomicrograph (plane light with white card technique) from 5870.9 feet, Little Ute field, Montezuma County, Colorado. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

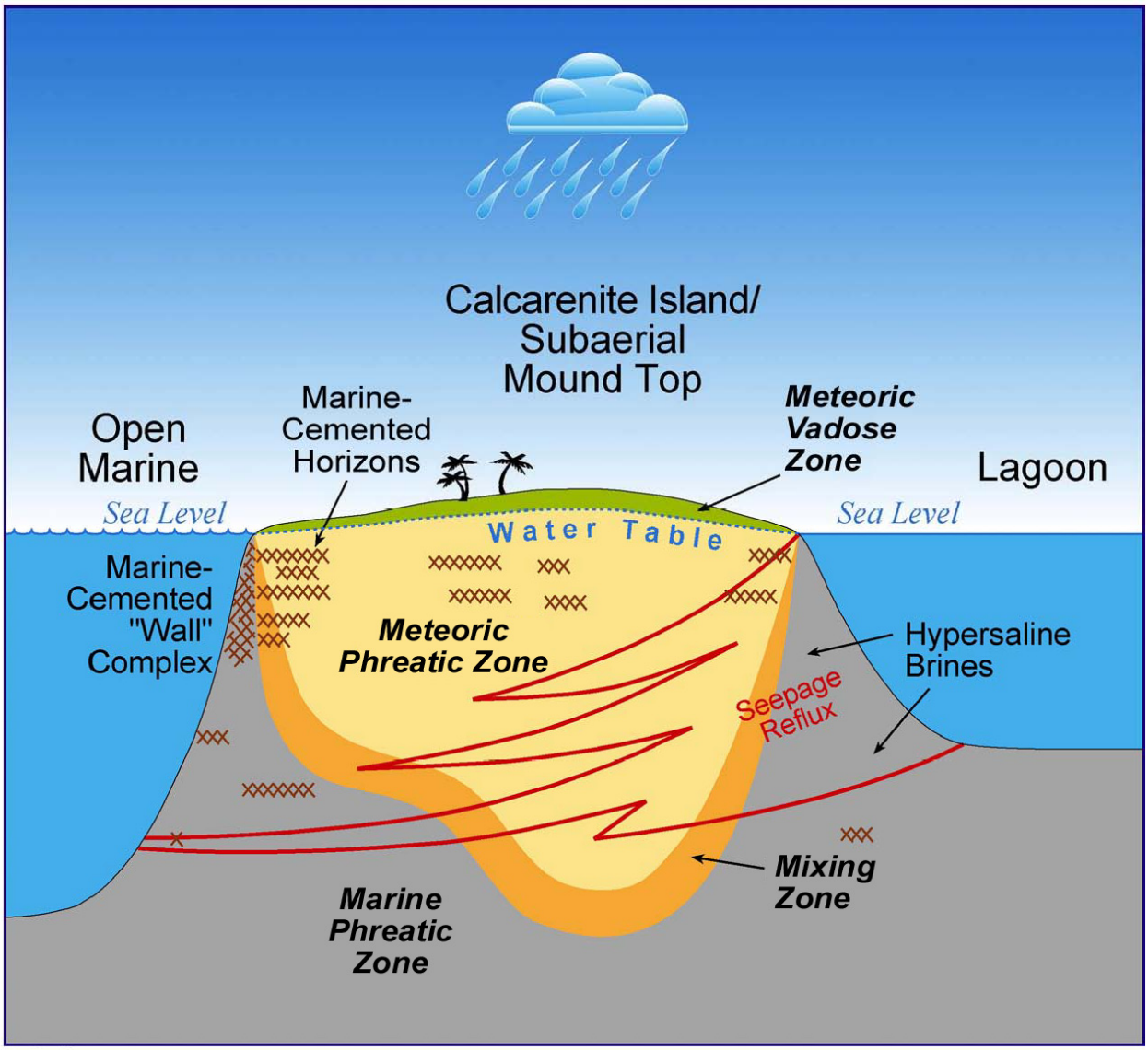


Figure 10-42. Model of early diagenetic environments found in the Desert Creek zone of the Paradox Formation, southern Paradox Basin (modified from Longman, 1980).

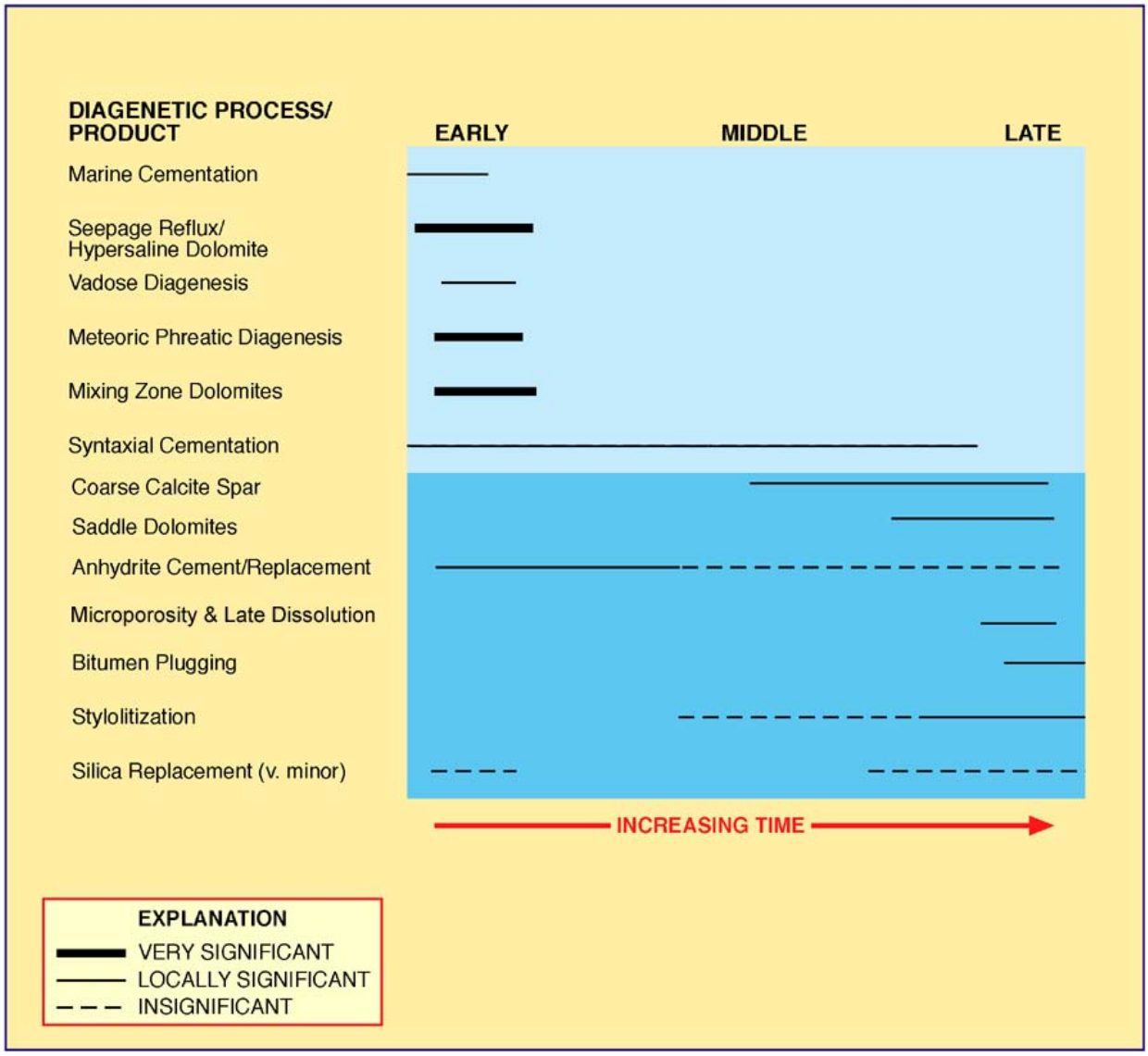


Figure 10-43. Typical diagenetic sequence through time based on thin section analysis, Ismay and Desert Creek zones.



Figure 10-44. Typical pattern of marine cementation within the well-lithified Desert Creek zone "wall" complex. Blue Hogan No. 1-J-1 well (section 1, T. 42 S., R. 23 E., SLBL&M), slabbed core from 5415.5 to 5416.1 feet, Desert Creek field, San Juan County, Utah.

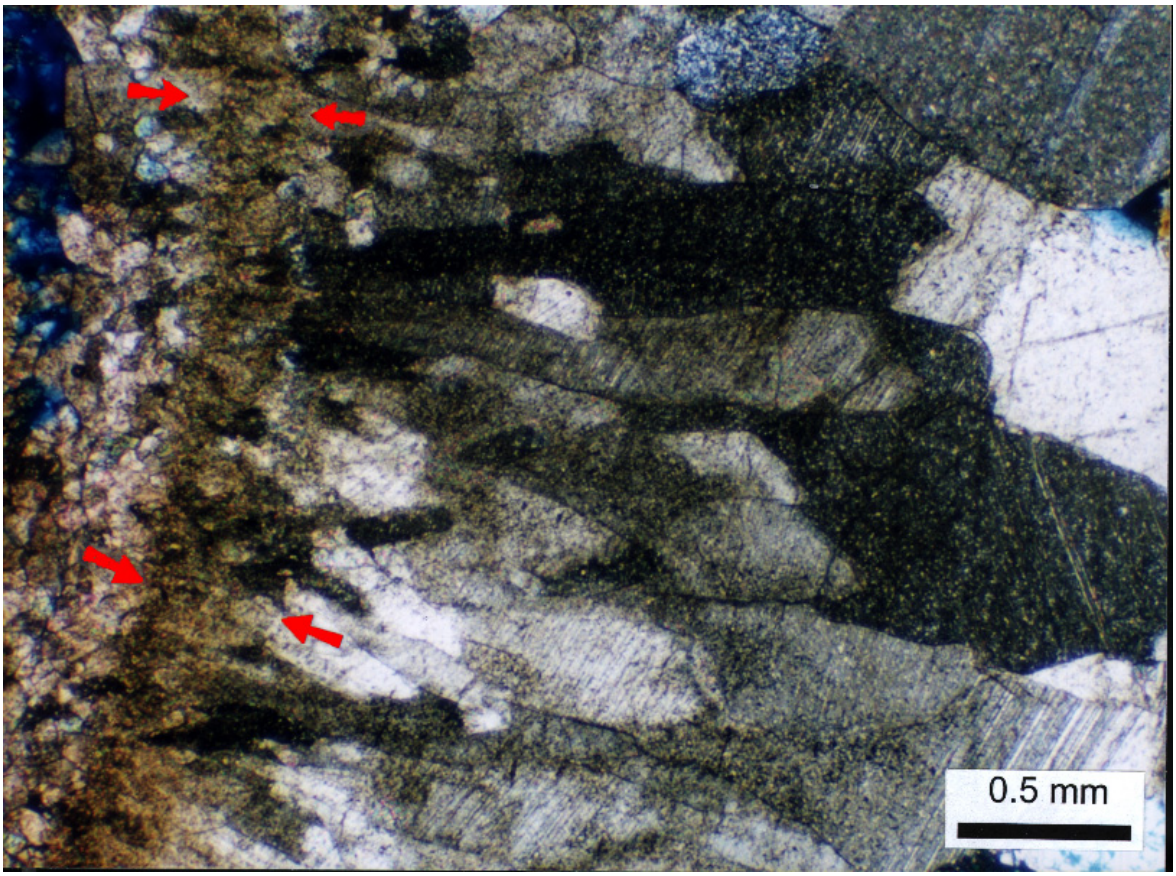


Figure 10-45. Two generations of probable early-marine cements. The earlier generation was a brown micritic to microfibrous cement (between arrows) which was followed by a bladed radiaxial generation. Filling of most original pore space was by the radiaxial cements. Blue Hogan No. 1-J-1 well (section 1, T. 42 S., R. 23 E., SLBL&M), photomicrograph (crossed nicols) from 5420.3 feet, Desert Creek field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

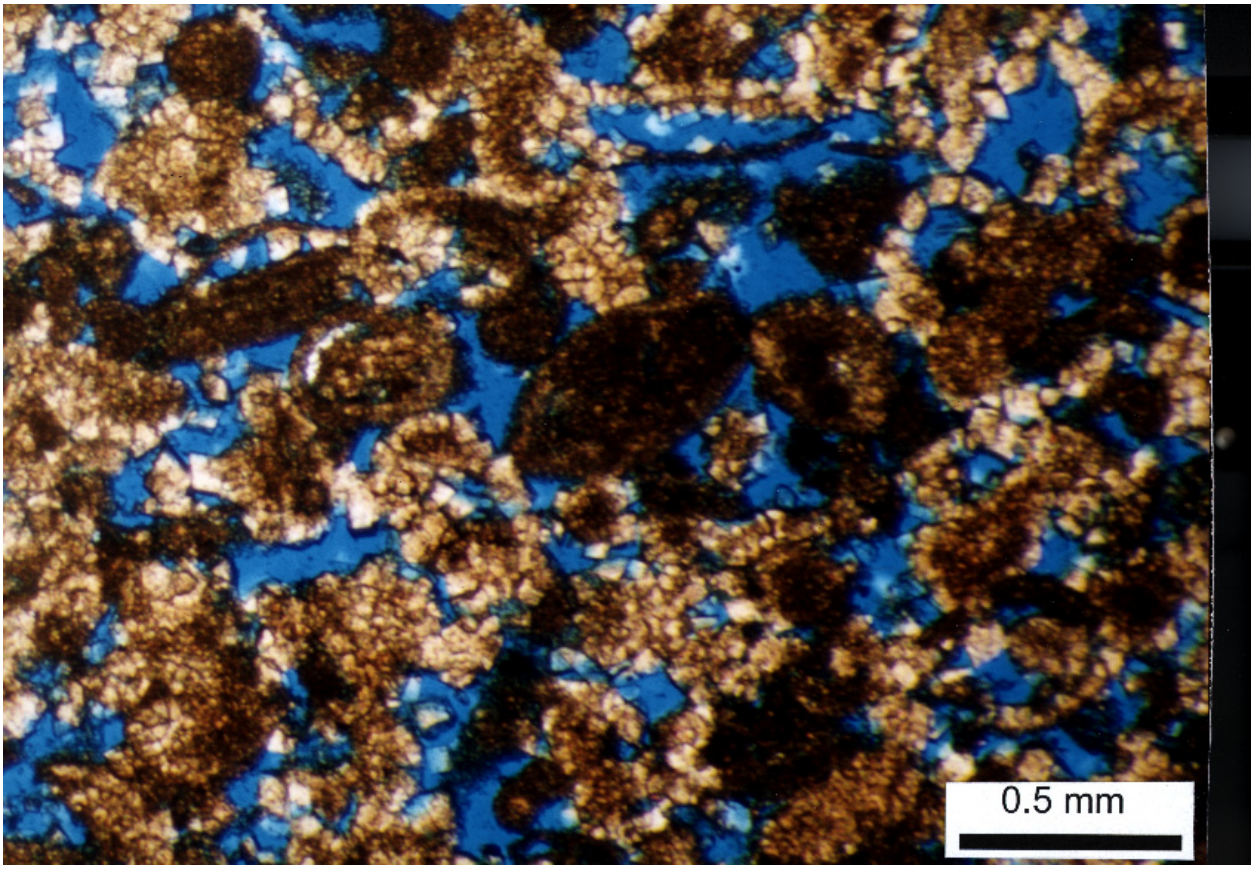


Figure 10-46. Typical Desert Creek-zone dolomitized, well-sorted, pelloidal/oolitic/bioclastic grainstone; porosity = 13.4%, permeability = 33.9 mD by core-plug analysis. Note the very fine crystalline dolomite formed by seepage reflux processes followed by partial dissolution and other meteoric overprints. The combination of both processes has led to good storage potential and excellent flow capacity. North Heron No. 35-C well (section 35, T. 41 S., R. 25 E., SLBL&M), photomicrograph (plane light) from 5569.2 feet, Heron field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

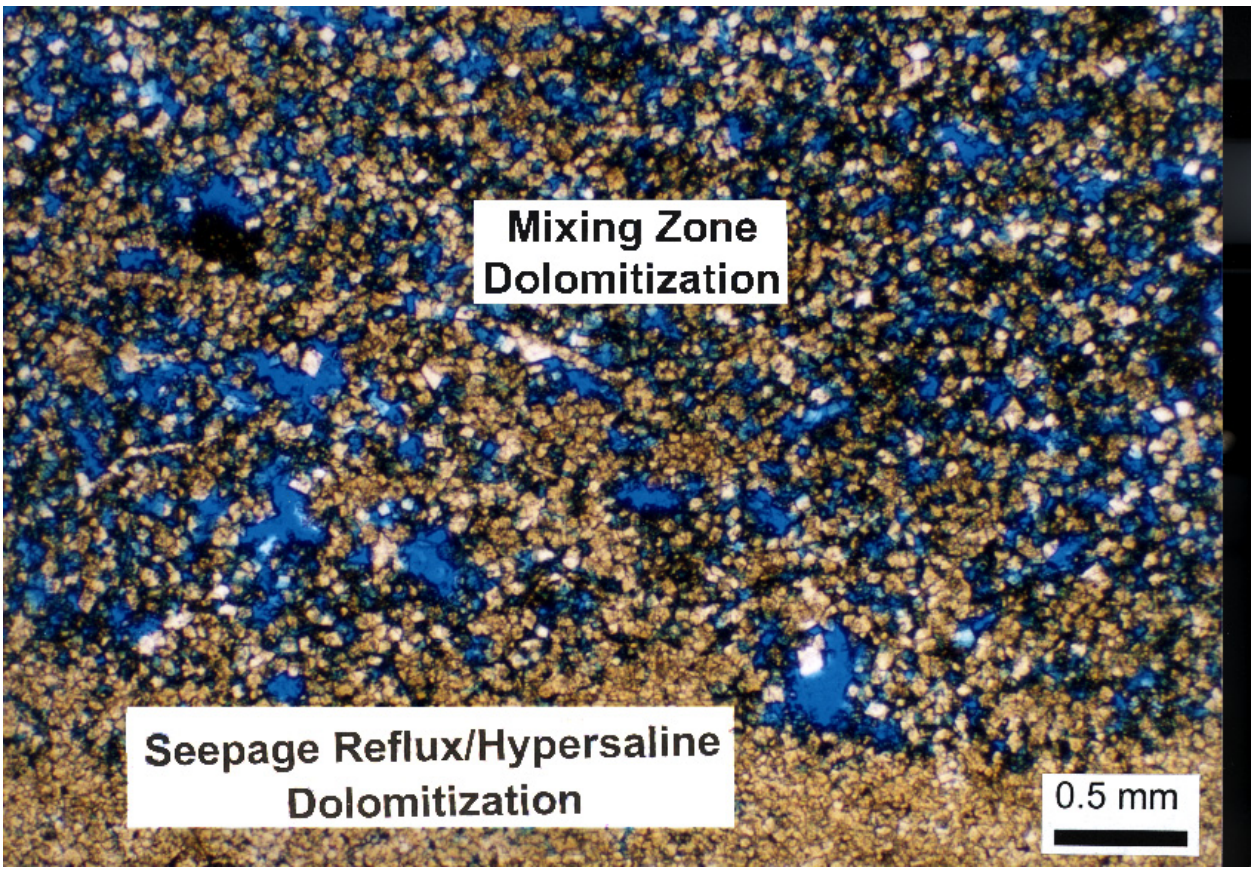


Figure 10-47. Desert Creek-zone dolomitized wackestone/packstone showing the contrast between probable seepage reflux/hypersaline dolomitization toward the base and more porous mixing-zone dolomitization above; porosity = 20.3%, permeability = 39.8 mD by core-plug analysis. Note "ghosts" of probable ostracods and crinoids. Runway No. 10-C-5A well (section 10, T. 40 S., R. 25 E., SLBL&M), photomicrograph (plane light) from 6120.2 feet, Runway field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

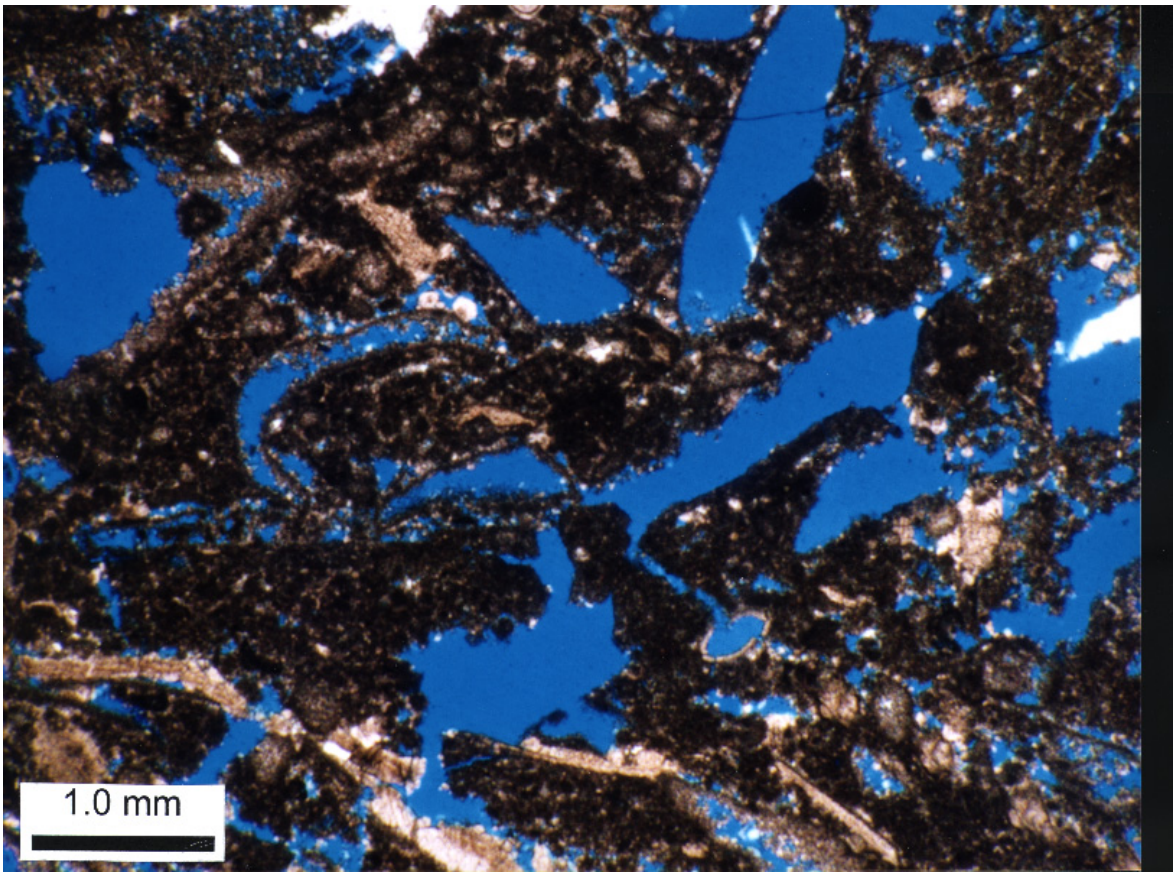


Figure 10-48. Desert Creek-zone grainstone/packstone showing interconnected solution-channel and moldic porosity with very little visible meteoric cements; porosity = 13.2%, permeablility = 20.4 mD by core-plug analysis. Mule No. 31-M well (section 31, T. 41 S., R. 24 E., SLBL&M), photomicrograph (plane light) from 5729.8 feet, Greater Aneth field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

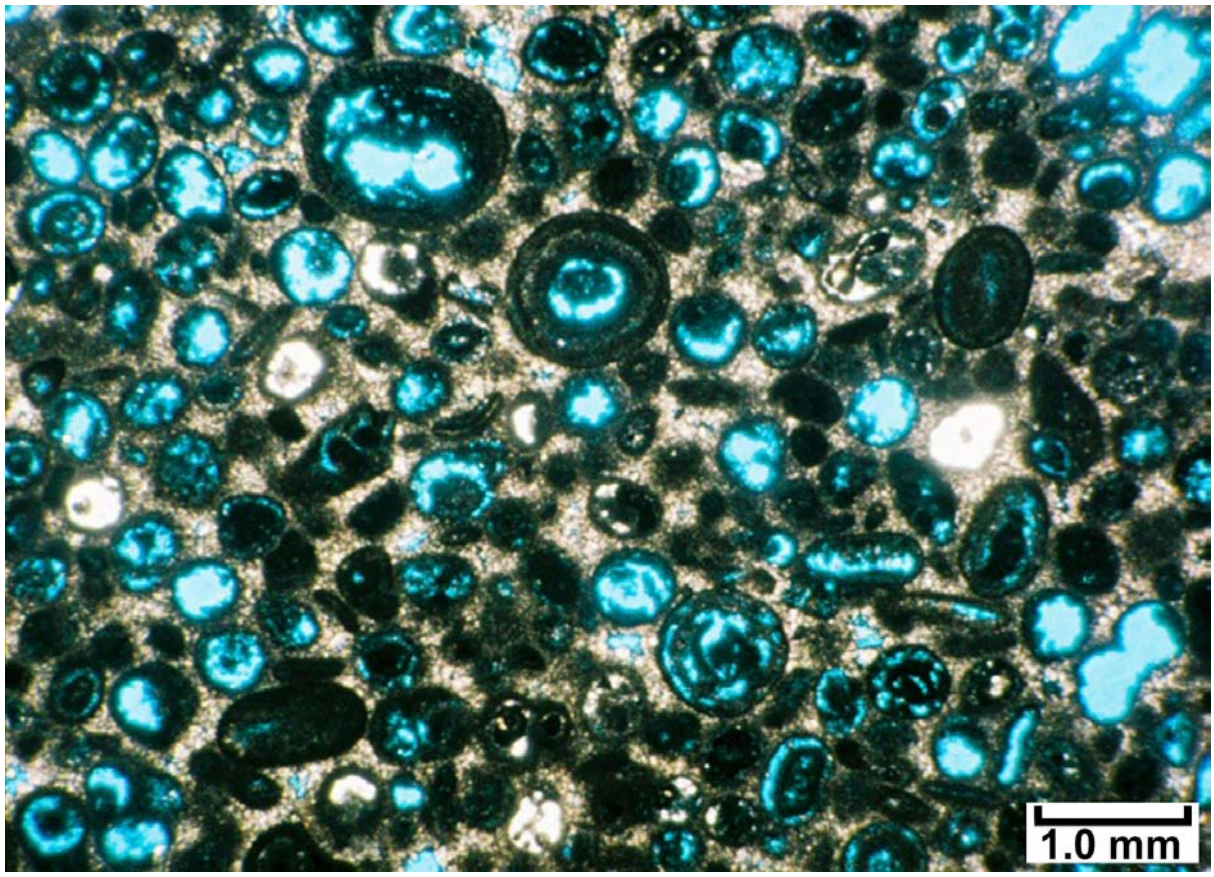


Figure 10-49. Desert Creek-zone grainstone showing oomoldic porosity with very little interconnection between pores; porosity = 10.3%, permeablility = 0.1 mD by core-plug analysis. Aneth Unit No. E-313 well (section 13, T. 4 S., R. 24 E., SLBL&M), photomicrograph (plane light) from 5767.6 feet, Greater Aneth field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

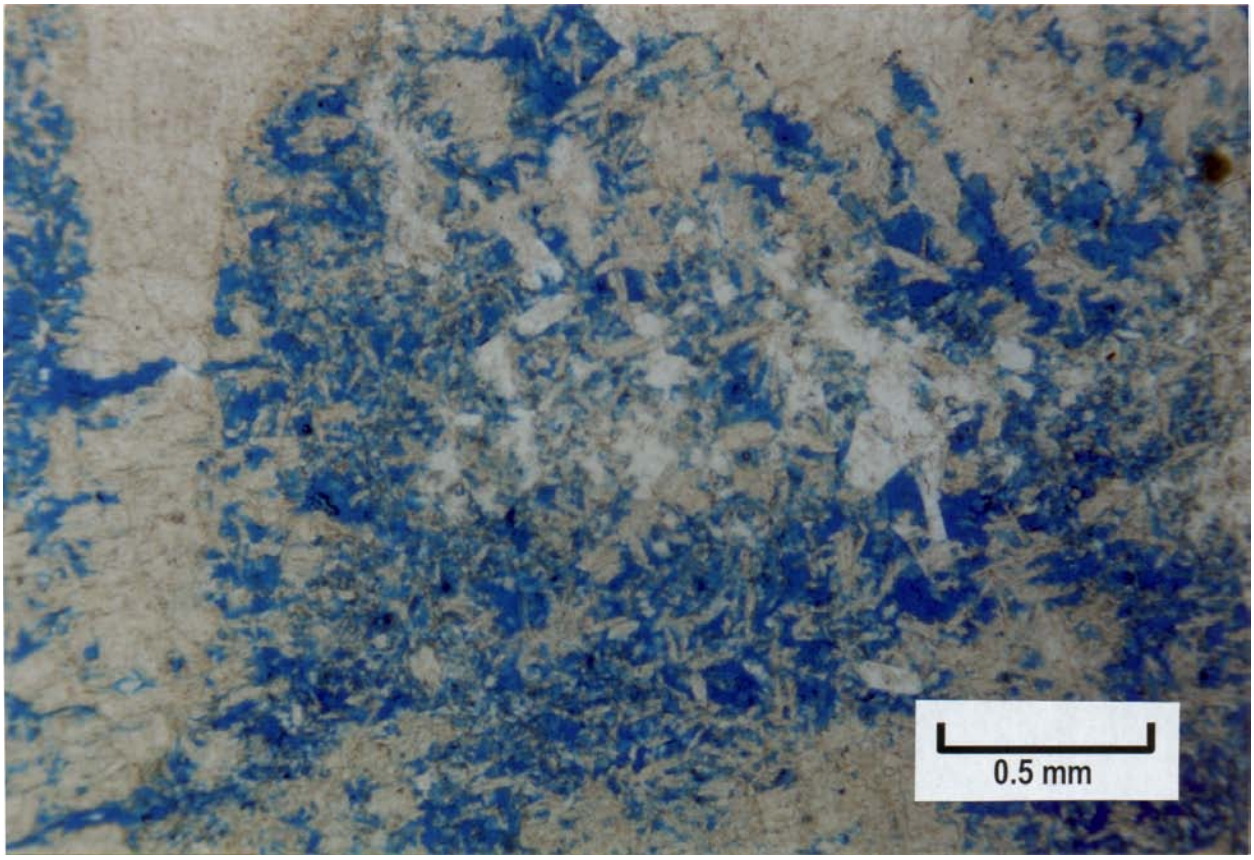


Figure 10-50. Desert Creek-zone dolomitized, phylloid-algal bafflestone showing a pattern of patchy dolomite dissolution which includes a "micro-box-work" pattern of pores (in blue); porosity = 10.5%, permeability = 7.5 mD by core-plug analysis. Bug No. 10 well (section 22, T. 36 S., R. 26 E., SLBL&M), photomicrograph (plane light with white card technique) from 6327.5 feet, Bug field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

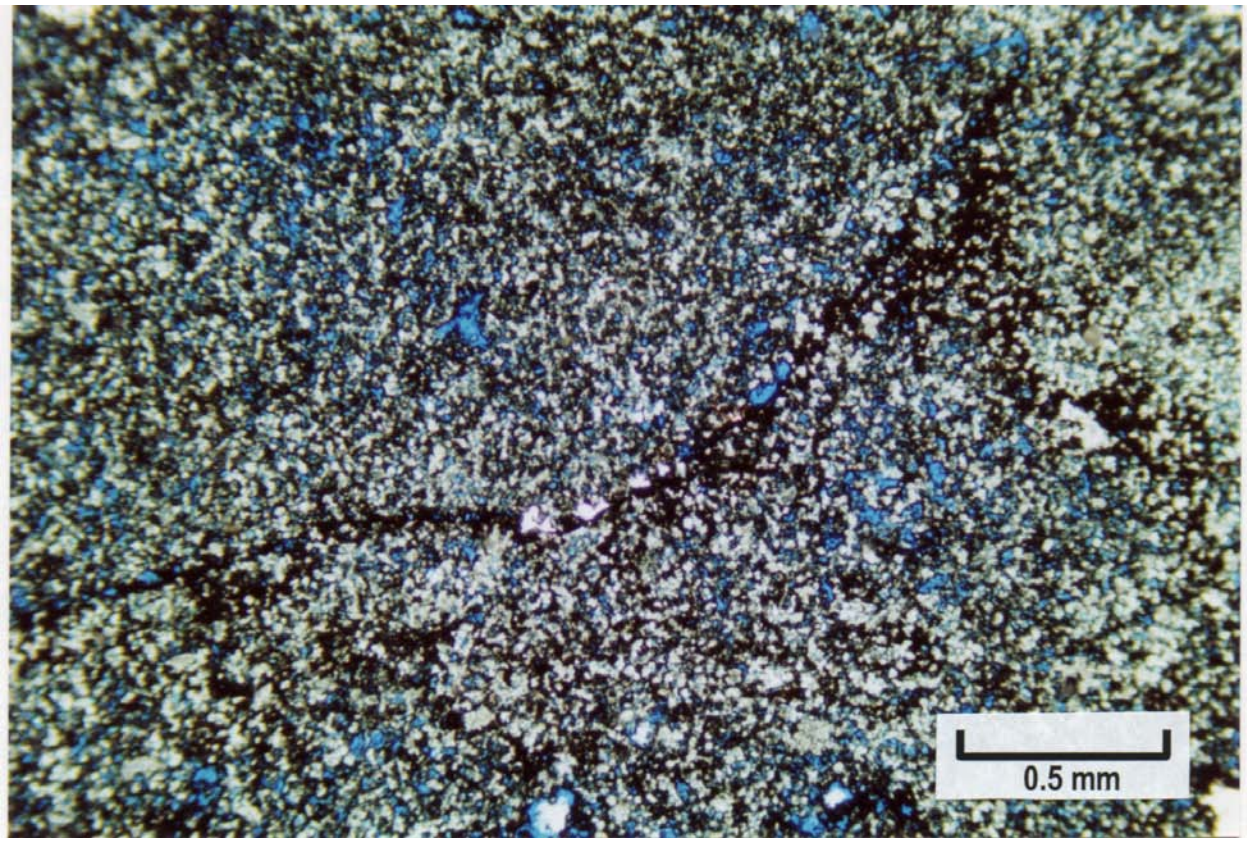


Figure 10-51. Ismay-zone peloidal packstone/grainstone dominated by microporosity and bitumen plugging; porosity = 22.9%, permeability = 215 mD. Cherokee No. 22-14 well (section 14, T. 37 S., R. 23 E., SLBL&M), photomicrograph (plane light) from 5768.7 feet, Cherokee field, San Juan County, Utah. Photomicrograph by David E. Eby, Eby Petrography & Consulting, Inc.

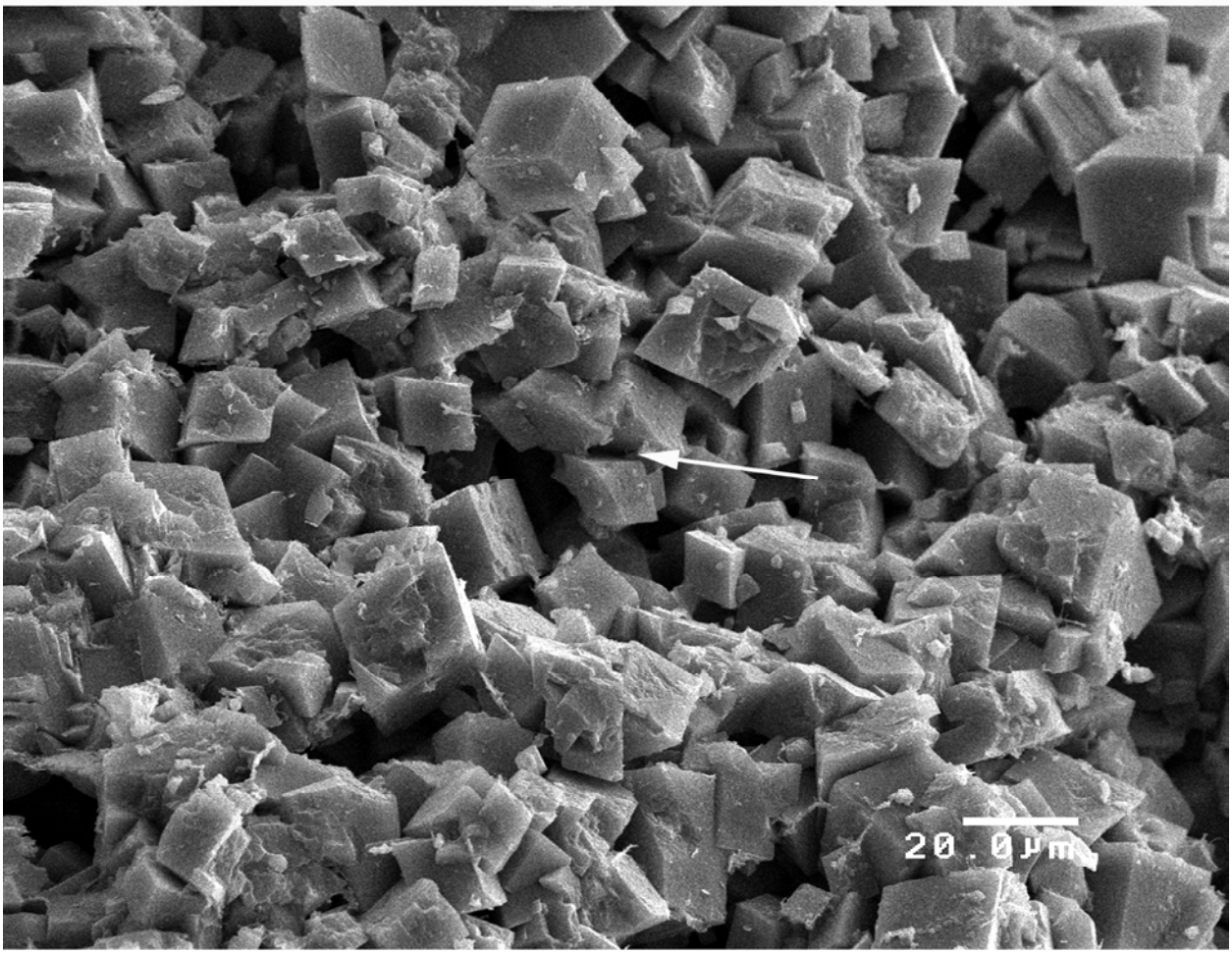


Figure 10-52. Ismay-zone packstone/grainstone displaying well-developed dolomite rhombs exhibiting abundant intercrystalline microporosity (arrow); porosity = 23.6%; permeability = 103 mD by core-plug analysis. Cherokee No. 33-14 well (section 14, T. 37 S., R. 23 E., SLBL&M), scanning electron microscope photomicrograph (scale represents 20 microns [0.02 mm]) of a core plug from 5781.2 feet, Cherokee field, San Juan County, Utah. Photomicrograph by Louis H. Taylor, Standard Geological Services, Inc.

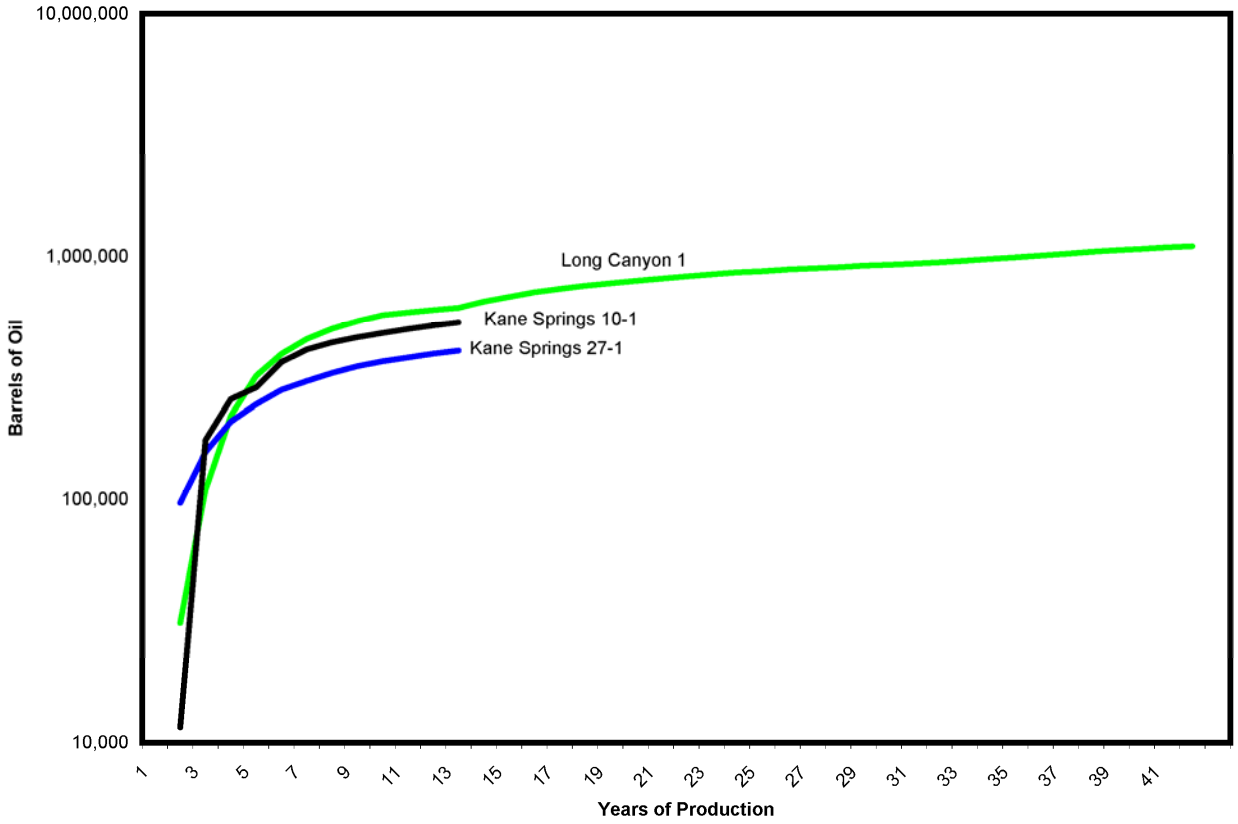


Figure 10-53. Cumulative production curves for the vertical Long Canyon No. 1 well and the horizontally drilled Kane Springs Nos. 10-1 and 27-1 wells. The Kane Springs Nos. 10-1 and 27-1 wells are the most productive of the horizontally drilled wells. Horizontal drilling does not appear to improve the cumulative production of a well, but it does improve the exploratory success of Cane Creek drilling.

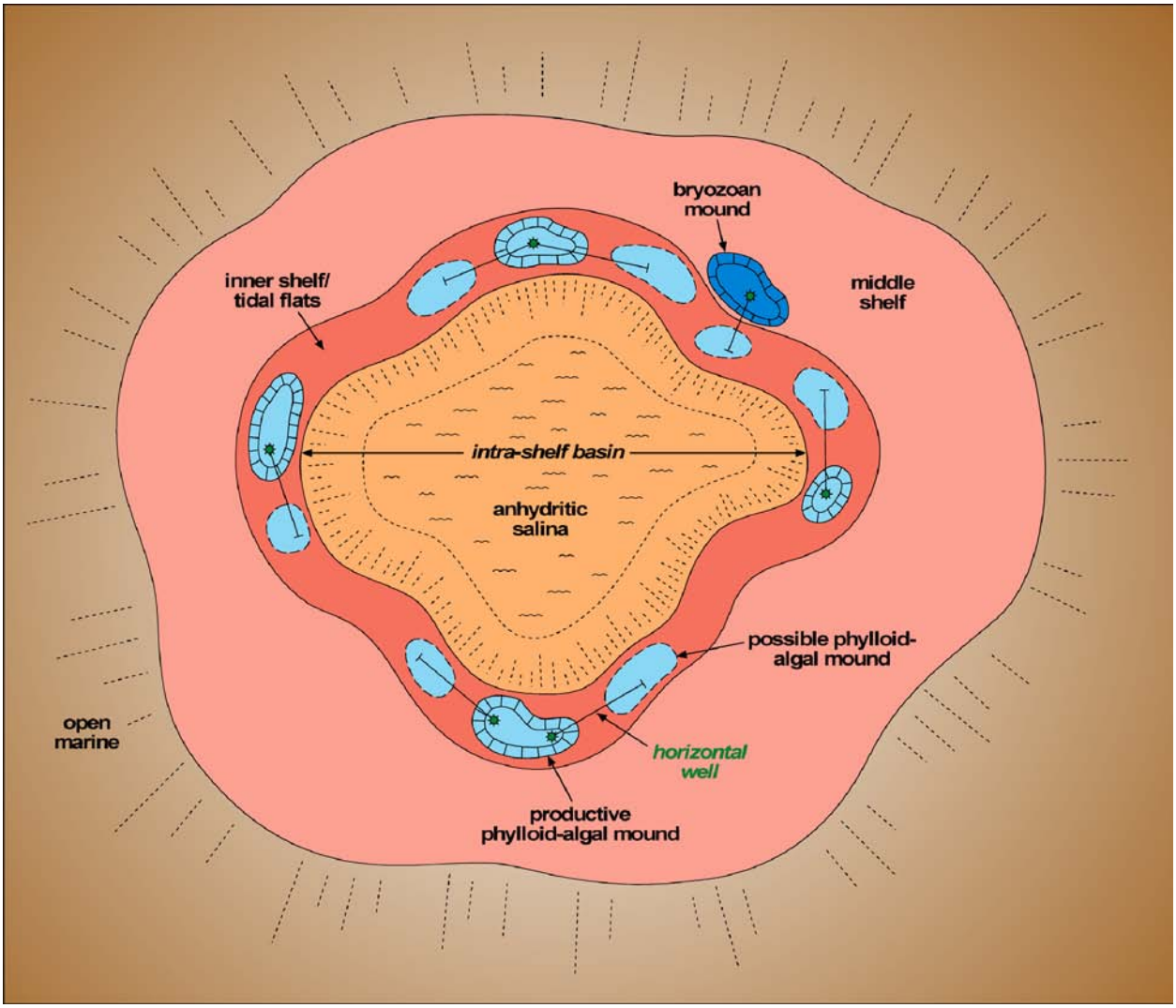


Figure 10-54. Map view of an ideal upper Ismay intra-shelf basin surrounded by a ring of inner shelf/tidal flat sediments (shown in red) which encase phylloid-algal mound clusters (in light blue). The central portion of the intra-shelf basin is the location of thick anhydrite (in orange) accumulation. Outboard from the inner shelf/tidal flat and mound fairway are low-energy middle-shelf and open-marine carbonates.

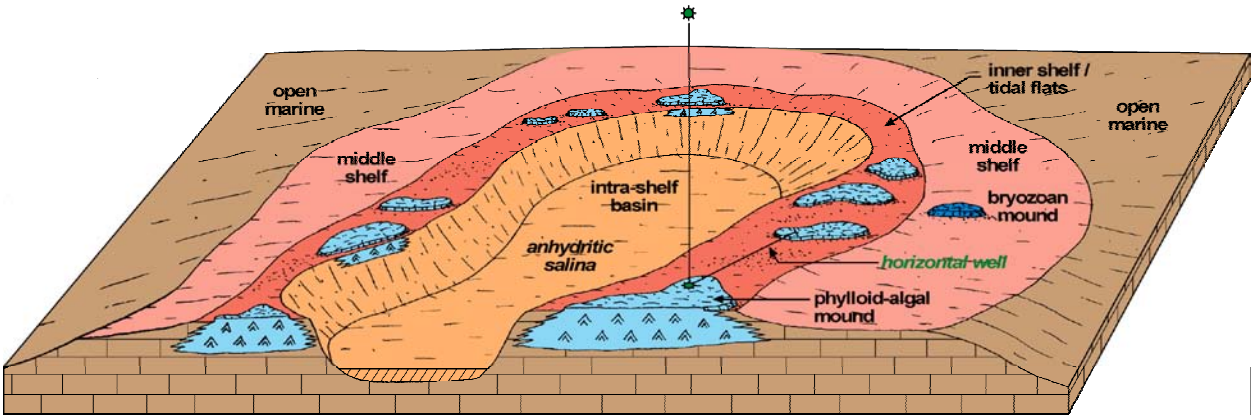


Figure 10-55. Cut-away block diagram showing the possible spatial relationships of upper Ismay facies types controlled by an intra-shelf basin. Phylloid-algal mounds (in light blue) are the principal reservoir within a curvilinear band that rims the intra-shelf basin. A hypothetical vertical well into a known mound reservoir is used as a kick-off location for horizontal drilling into previously undrained mounds.

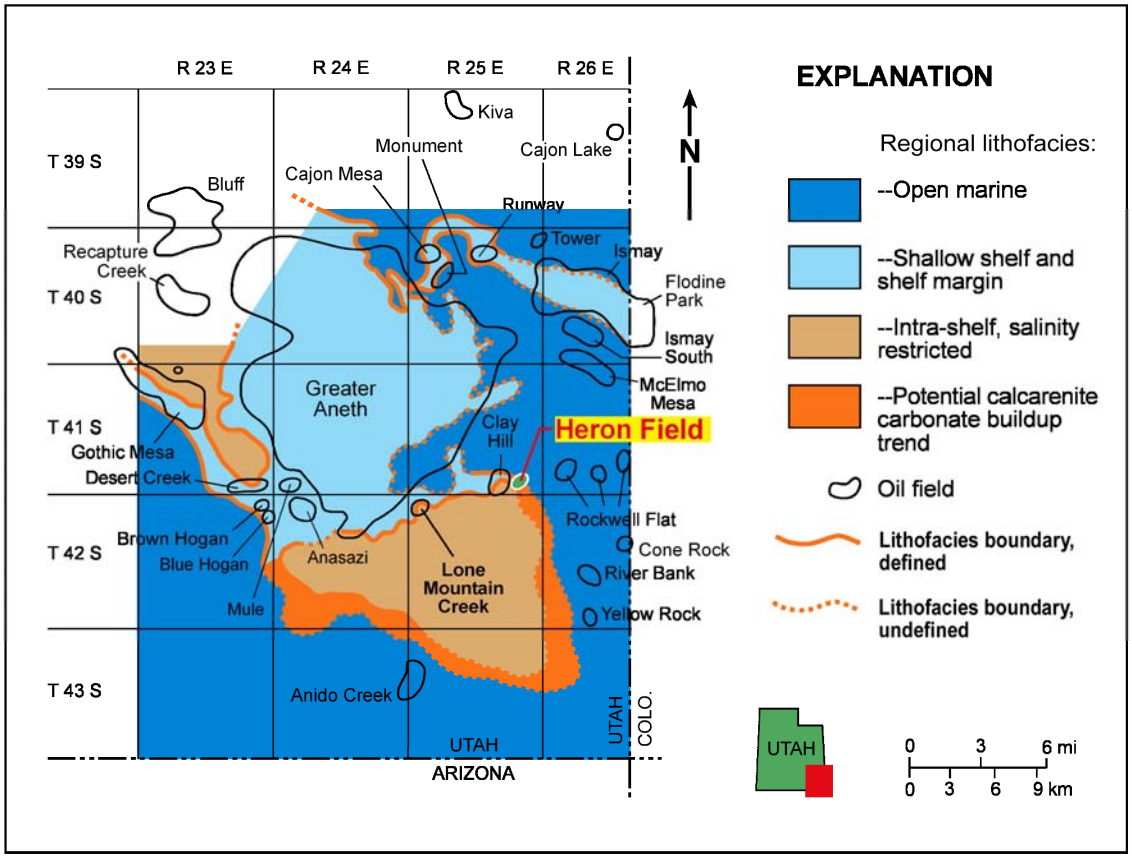


Figure 10-56. Potential calcarenite buildup trend (orange) within the regional lithofacies belts of the Desert Creek zone, southeastern Utah. Heron field (highlighted) is an excellent example of a lenticular, mound/beach complex hydrocarbon trap in this trend.

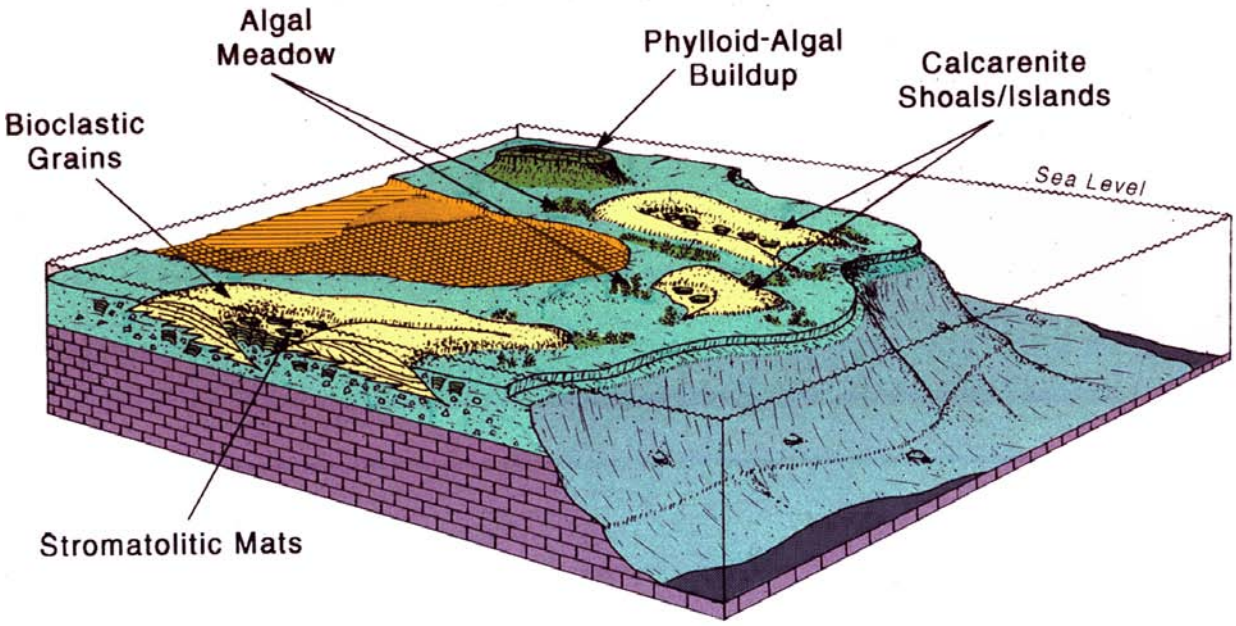


Figure 10-57. Depositional environments of the calcarenite lithofacies along the narrow shelf margin between the open-marine and intra-shelf, salinity-restricted lithofacies belts.

Table 10-1. Well and production data for fields in the fractured shale, Blanding sub-basin Desert Creek zone, Blanding sub-basin Ismay-zone, and Aneth platform Desert Creek-zone subplays, Pennsylvanian Paradox Formation play (data from Colorado Oil & Gas Conservation Commission, 2008; Utah Division of Oil, Gas and Mining, 2008; Steve Rauzi, Arizona Geological Survey, written communication, 2006).

State	County	Field	Zone	Discovery Date	Active Producers	Abandoned Producers	Acres	Spacing (acres)	Average Monthly Production		Cumulative Production	
									Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (BCF)
Blanding Sub-Basin Desert Creek Zone Subplay												
Colorado	Montezuma	Island Butte	Desert Creek	1991	6	2	NA	NA	837	130	2,196,781	5.9
Colorado	Montezuma	McClean	Desert Creek	1974	6	2	NA	NA	12,620	48,402	5,060,689	17.4
Colorado	Dolores/Montezuma	Papoose Canyon	Desert Creek	1970	30	13	1920	160	3690	50,409	6,507,460	36.4
Utah	San Juan	Bug	Desert Creek	1980	7	6	600	160	0	0	1,622,863	4.5
Blanding Sub-Basin Ismay Zone Subplay												
Colorado	Montezuma	Cache	Ismay	1964	10	10	1040	40	1456	19,050	4,582,519	7.6
Colorado	Montezuma	Flodine Park	Ismay	1959	7	3	1440	80	299	3414	2,580,961	9.8
Colorado	Montezuma	Marble Wash	Ismay	1958	5	3	400	80	10	222	1,013,349	1.7
Colorado	Montezuma	Roadrunner	Ismay	1984	11	3	NA	40	923	2478	2,176,601	4.5
Colorado	Montezuma	Towaoc	Ismay	1959	5	2	160	80	348	1220	802,762	1.2
Utah	San Juan	Cave Canyon	Ismay	1984	10	0	30	20	1447	2366	2,431,098	3.9
Utah	San Juan	Deadman-Ismay	Ismay	1986	4	1	120	40	435	6235	797,446	12.4
Utah	San Juan	Ismay	Ismay	1956	10	24	4370	80	2707	3604	10,822,986	17.5
Utah	San Juan	Kachina	Ismay	1986	5	0	400	80	1732	2875	2,594,130	2.3
Utah	San Juan	Kiva	Ismay	1984	5	0	350	80	856	1722	2,644,724	3.8
Utah	San Juan	McElmo Mesa	Ismay	1960	0	9	2240	80	0	0	2,219,175	2.9
Utah	San Juan	Mustang Flat	Ismay	1982	8	1	320	160	252	15,305	780,988	16.7
Utah	San Juan	Patterson Canyon	Ismay	1974	9	3	320	none	899	2281	1,093,285	2.7
Utah	San Juan	Tin Cup Mesa	Ismay	1980	10	0	880	80	682	1537	2,474,548	3.7
Aneth platform Desert Creek Zone Subplay												
Arizona	Apache	Boundary Butte East	Ismay-Desert Creek-Akah	1954	3	7	2800	80	199	934	885,530	9.8
Utah	San Juan	Akah	Ismay-Desert Creek-Akah	1955	2	0	240	80	200	228	531,563	0.5
Utah	San Juan	Anido Creek	Ismay-Desert Creek	1960	0	4	375	80	0	0	612,082	0.4
Utah	San Juan	Bluff	Desert Creek	1951	8	7	1040	none	218	1552	1,674,759	3.7
Utah	San Juan	Clay Hill	Desert Creek	1977	3	1	200	none	379	283	997,134	1.4
Utah	San Juan	Desert Creek	Desert Creek	1954	6	1	300	80	2864	1920	2,086,755	1.8
Utah	San Juan	Gothic Mesa	Desert Creek	1956	5	10	1520	80	329	0	1,946,420	1.3
Utah	San Juan	Greater Aneth	Desert Creek	1956	462	106	48,260	40	294,906	227,902	440,260,717	384.9
Utah	San Juan	Recapture Creek	Ismay-Desert Creek	1956	5	2	1350	80	1071	2484	2,224,172	3.8
Utah	San Juan	Runway	Desert Creek	1990	3	0	193	40	427	1414	866,568	3.0
Utah	San Juan	Tohonadla	Ismay-Desert Creek-Akah	1957	4	0	1200	80	1925	0	2,286,715	0.9
Utah	San Juan	Turner Bluff	Desert Creek	1957	7	4	720	80	202	611	927,110	0.8
Fracture Shale Subplay												
Utah	Grand	Long Canyon	Cane Creek shale	1962	1	1	NA	none	303	279	1,132,851	1.2
Utah	Grand	Big Flat	Cane Creek shale	1961	4	2	NA	none	14,736	15,358	1,232,517	1.3

Table 10-2. Reservoir data for fields in the fractured shale, Blanding sub-basin Desert Creek-zone, Blanding sub-basin Ismay-zone, and Aneth platform Desert Creek-zone subplays, Pennsylvanian Paradox Formation play.

State	County	Field	Zone	Pay (feet)	Porosity (%)	Perm. (mD)	Temp. (°F)	Initial Reservoir Pressure (psi)	Water Saturation	Resistivity of Formation Water	Salinity	Drive
Blanding Sub-Basin Desert Creek Zone Subplay												
Colorado	Montezuma	Island Butte [1]	Desert Creek	NA	NA	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	McClean [1, 2, 3]	Desert Creek	30	14	250	130	3595	69	0.045@68°F	348,534	solution gas/water drive
Colorado	Dolores/Montezuma	Papoose Canyon [1, 4]	Desert Creek	9	12.2	4.4	NA	3416	53	NA	NA	gas cap expansion
Utah	San Juan	Bug [5, 6, 7]	Desert Creek	15	11	27.5	170	3550	32	0.03@BHT	331,831	gas cap expansion/solution gas/limited water drive
Blanding Sub-Basin Ismay Zone Subplay												
Colorado	Montezuma	Cache [1, 8]	Ismay	57	10.4	12.3	NA	2170	35	0.11@68°F	62,700	solution gas/part water drive
Colorado	Montezuma	Flodine Park [1, 9]	Ismay	41	11	13	NA	2212	41	NA	NA	solution gas
Colorado	Montezuma	Marble Wash [1, 10]	Ismay	15	10	2	NA	2250	NA	0.051@68°F	234,685	solution gas
Colorado	Montezuma	Roadrunner [1]	Ismay	NA	NA	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	Towaoc [1, 11]	Ismay	16	10	25	NA	2290	44	NA	NA	solution gas/water drive
Utah	San Juan	Cave Canyon [12]	Ismay	75	14	55	132	2121	11	0.02@BHT	NA	fluid expansion/solution gas
Utah	San Juan	Deadman-Ismay [13]	Ismay	62	13	0.9	132	2441	18-46	0.047@68°F	NA	gas expansion/depletion
Utah	San Juan	Ismay [14, 15]	Ismay	24	11.2	16.5	131	2205	41	NA	NA	solution gas
Utah	San Juan	Kachina [16]	Ismay	100	13	8	132	2108	23	NA	NA	solution gas
Utah	San Juan	Kiva [17]	Ismay	38	16	21.9	135	1862	24	NA	NA	solution gas
Utah	San Juan	McElmo Mesa [18]	Ismay	29	9	NA	119	2176	37	NA	NA	water drive
Utah	San Juan	Mustang Flat [19]	Ismay	30	9	4	126	2642	34	NA	NA	gas expansion/water drive
Utah	San Juan	Patterson Canyon [20, 21]	Ismay	17	13	10	128	2572	41	0.054@68°F	222,554	solution gas/water drive
Utah	San Juan	Tin Cup Mesa [22, 23, 24]	Ismay	50	14.3	8.3	121	2080	31	0.065@77°F	256,894	solution gas
Aneth Platform Desert Creek Zone Subplay												
Arizona	Apache	Boundary Butte East [25]	Ismay-Desert Creek-Akah	20	8	2.3	NA	1550	20	NA	62,000	gas expansion/solution gas
Utah	San Juan	Akah [26]	Ismay-Desert Creek-Akah	NA	NA	NA	112	1875	NA	NA	NA	water drive/gas expansion
Utah	San Juan	Anido Creek [27]	Ismay-Desert Creek	19	8	24	105	1974	28	NA	80,000-100,000	solution gas/fluid expansion
Utah	San Juan	Bluff [28, 29]	Desert Creek	33	7.5	0.3	140	1800	NA	NA	NA	solution gas
Utah	San Juan	Clay Hill [30]	Desert Creek	40	14	30	115	2000	25	0.03@130°F	191,000	solution gas
Utah	San Juan	Desert Creek [31]	Desert Creek	26	13	5	126	2005	28	NA	NA	solution gas/fluid expansion
Utah	San Juan	Gothic Mesa [32]	Desert Creek	10	8.8	1.6	124	2150	45	NA	NA	pressure depletion
Utah	San Juan	Greater Aneth [33, 34, 35]	Desert Creek	50	12	20	125	2170	24	NA	150,000	solution gas/fluid expansion
Utah	San Juan	Recapture Creek [36]	Ismay-Desert Creek	19	10.9	1.6	130	2175	23	NA	160,000	solution gas/weak water drive
Utah	San Juan	Runway [37]	Desert Creek	50	11.9	17.3	126	2162	10-63	0.07@67°F	199,709	gas expansion
Utah	San Juan	Tohonadla [38]	Ismay-Desert Creek-Akah	25	6.5	12.5	126	1895	24	NA	82,000	solution gas
Utah	San Juan	Turner Bluff [39, 40]	Desert Creek	15	9	2	124	1637	28	0.07@68°F	120,000	solution gas
Fractured Shale Subplay												
Utah	Grand	Long Canyon[41]	Cane Creek shale	25	NA	NA	NA	5000	NA	NA	NA	solution gas
Utah	Grand	Big Flat[42]	Cane Creek shale	75	2.1	39-400	132	7417	10	NA	NA	solution gas

NA = not available

[1]Scott (2003), [2]Matheny and Martin (1987), [3]Mickel (1978a), [4]Miesner (1978), [5]Martin (1983), [6]Oline (1996), [7]Krivanek (1981), [8]Wold (1978), [9]Mecham (1978a), [10]Brown (1978), [11]Spencer (1978), [12]Lentz (1993), [13]Ross and Handley (1993), [14]Mecham (1978b), [15]Dawson (1988), [16]Crawley-Stewart and Riley (1993a), [17]Crawley-Stewart and Riley (1993b), [18]Mickel (1978b), [19]Brown (1983), [20]Martin (1981) [21]Krivanek (1978), [22]Ott and Roylance (1983), [23]Herrod and Gardner (1988), [24]Steele and White (1993), [25]Dunn (1978), [26]Riggs (1978), [27]Lauth (1978a), [28]Campbell (1978), [29]Baars (1993), [30]Lehman (1983), [31]Lauth (1978b), [32]Reid and Stevenson (1978), [33]Babcock (1978a, 1978b, 1978c, 1978d), [34]Peterson (1992), [35]Moore and Hawks (1993), [36]Scanlon and Wendling (1983), [37]Chidsey and others (1996a), [38]Norton (1978), [39]Mickel (1978c), [40]Krivanek (1993), [41]Smith (1978d), [42]Grove and others (1993).

Table 10-3. Oil properties for fields in the fractured shale, Blanding sub-basin Desert Creek-zone, Blanding sub-basin Ismay-zone, and Aneth platform Desert Creek-zone subplays, Pennsylvanian Paradox Formation play.

State	County	Field	Zone	Gas/Oil Ratio	Oil Characteristics					
					API Gravity	Color	Viscosity	Pour Point (°F)	Sulfur (%)	Nitrogen (%)
Blanding Sub-Basin Desert Creek Zone Subplay										
Colorado	Montezuma	Island Butte	Desert Creek	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	McClean [1, 2]	Desert Creek	2200	46°	light reddish brown	NA	0.09	NA	NA
Colorado	Dolores/Montezuma	Papoose Canyon [3]	Desert Creek	NA	50°	light green/straw yellow	NA	NA	NA	NA
Utah	San Juan	Bug [4, 5]	Desert Creek	1900	47°	light reddish brown	NA	0	NA	NA
Blanding Sub-Basin Ismay Zone Subplay										
Colorado	Montezuma	Cache [6]	Ismay	918	45°	NA	0.35 sus	NA	NA	NA
Colorado	Montezuma	Flodine Park [7]	Ismay	NA	45°	green	NA	NA	NA	NA
Colorado	Montezuma	Marble Wash [8]	Ismay	2200	42°	NA	NA	NA	NA	NA
Colorado	Montezuma	Roadrunner	Ismay	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	Towaoc [9]	Ismay	754	42°	NA	NA	NA	NA	NA
Utah	San Juan	Cave Canyon [10]	Ismay	529	44°	black	NA	NA	0	NA
Utah	San Juan	Deadman-Ismay [11]	Ismay	5556	40-47°	NA	NA	5-10	NA	NA
Utah	San Juan	Ismay [12, 13]	Ismay	NA	46°	brownish green	33 sec@100°F	10	0.05	0.02
Utah	San Juan	Kachina [14]	Ismay	745	39°	NA	0.443 sus	55	NA	NA
Utah	San Juan	Kiva [15]	Ismay	645	41°	NA	0.64 sus	35	NA	NA
Utah	San Juan	McElmo Mesa	Ismay	NA	NA	NA	NA	NA	NA	NA
Utah	San Juan	Mustang Flat [16]	Ismay	76,508	53°	NA	NA	NA	NA	NA
Utah	San Juan	Patterson Canyon [17]	Ismay	NA	42°	yellow brown	NA	>0	NA	NA
Utah	San Juan	Tin Cup Mesa [18]	Ismay	1390	44°	yellow brown	NA	15	NA	NA
Aneth Platform Desert Creek Zone Subplay										
Arizona	Apache	Boundary Butte East [19]	Ismay-Desert Creek-Akah	NA	41°	NA	NA	NA	NA	NA
Utah	San Juan	Akah [20]	Ismay	NA	39°	dark green	NA	25	0.2	0.06
Utah	San Juan	Anido Creek [21]	Ismay-Desert Creek	NA	43°	green	NA	NA	NA	NA
Utah	San Juan	Bluff [12, 22, 23]	Desert Creek	NA	41.4°	green	38 sec@100°F	25	0.05	0.019
Utah	San Juan	Clay Hill [24]	Desert Creek	NA	41°	NA	NA	NA	NA	NA
Utah	San Juan	Desert Creek [12, 25]	Desert Creek	NA	39°	green	40 sec @100°F	50	0.11	0.04
Utah	San Juan	Gothic Mesa [12, 26]	Desert Creek	NA	42°	green	37 sec@100°F	25	0.05	0.03
Utah	San Juan	Greater Aneth [12, 27]	Desert Creek	665	38-42°	green	0.53 sus	10	0.07	0.04
Utah	San Juan	Recapture Creek [12, 28]	Ismay-Desert Creek	NA	40°	green	35 sec@100°F	20	0.1	0.03
Utah	San Juan	Runway [29]	Desert Creek	967	40.5°	dark green	0.314 sus	NA	0	NA
Utah	San Juan	Tohonadla [12, 30]	Ismay	NA	38°	brownish green	40 sec@100°F	20	0.09	0.07
Utah	San Juan	Turner Bluff [31]	Desert Creek	259	43°	dark brown	NA	NA	0.1	NA
Fractured Shale Subplay										
Utah	Grand	Long Canyon[32]	Cane Creek shale	NA	40°	NA	NA	25	Trace	NA
Utah	Grand	Big Flat[33]	Cane Creek shale	850	43°	NA	NA	45	NA	NA

NA = not available, sus = Saybolt Univeral Seconds, sec = seconds

[1]Matheny and Martin (1987), [2]Mickel (1978a), [3]Miesner (1978), [4]Martin (1983), [5]Oline (1996), [6]Wold (1978), [7]Mecham (1978a), [8]Brown (1978), [9]Spencer (1978), [10]Lentz (1993), [11]Ross and Handley (1993), [12]Stowe (1972), [13]Mecham (1978b), [14]Crawley-Stewart and Riley (1993a), [15]Crawley-Stewart and Riley (1993b), [16]Brown (1983), [17]Krivanek (1978), [18]Steele and White (1993), [19]Dunn (1978), [20]Riggs (1978), [21]Lauth (1978a), [22]Campbell (1978), [23]Baars (1993), [24]Lehman (1983), [25]Lauth (1978b), [26]Reid and Stevenson (1978), [27]Moore and Hawks (1993), [28]Scanlon and Wendling (1983), [29]Chidsey and others (1996a), [30]Norton (1978), [31]Krivanek (1993), [32]Smith (1978d), [33]Grove and others (1993).

Table 10-4. Gas properties for fields in the fractured shale, Blanding sub-basin Desert Creek-zone, Blanding sub-basin Ismay-zone, and Aneth platform Desert Creek-zone subplays, Pennsylvanian Paradox Formation play.

State	County	Field	Zone	Gas Characteristics											
				Methane (%)	Ethane (%)	Propane (%)	Butane (%)	Pentaine (%)	Hexane + (%)	Nitrogen (%)	CO2 (%)	Helium (%)	Hydrogen Sulfide (%)	BTU	Specific Gravity
Blanding Sub-Basin Desert Creek Zone Subplay															
Colorado	Montezuma	Island Butte	Desert Creek	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	McClean [1, 2, 3]	Desert Creek	78	14	5	2	0.5	0.4	0.5	0.05	0.01	0	1254	0.715
Colorado	Dolores/Montezuma	Papoose Canyon [4]	Desert Creek	63	18	10	5	2	0.5	2	0.3	0.1	0	1475	0.870
Utah	San Juan	Bug [5, 6]	Desert Creek	78	13	5	2	0.5	0.3	0.63	0.08	0	0	1232	0.717
Blanding Sub-Basin Ismay Zone Subplay															
Colorado	Montezuma	Cache [7]	Ismay	66	16	9	3	NA	1	NA	0.6	NA	NA	1436	0.851
Colorado	Montezuma	Flodine Park [4]	Ismay	75	13	6	3	1	0.2	2	0.5	0.1	0	1247	0.763
Colorado	Montezuma	Marble Wash	Ismay	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	Roadrunner	Ismay	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Colorado	Montezuma	Towaoc [8]	Ismay	56	18	13	7	3	0.5	2	0.1	.02	0	1607	NA
Utah	San Juan	Cave Canyon	Ismay	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Utah	San Juan	Deadman-Ismay [9]	Ismay	74	15	7	2	0	0	1.3	0.05	0	0	1294	NA
Utah	San Juan	Ismay	Ismay	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Utah	San Juan	Kachina [10]	Ismay	65	17	10	NA	NA	NA	NA	NA	NA	Tr	1464	0.909
Utah	San Juan	Kiva [11]	Ismay	65	15	10	NA	NA	NA	NA	NA	NA	Tr	1515	0.9
Utah	San Juan	McElmo Mesa [12]	Ismay	61	19	11	5	2	1	1.8	0.1	Tr	0	NA	NA
Utah	San Juan	Mustang Flat	Ismay	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.6
Utah	San Juan	Patterson Canyon [13]	Ismay	57	22	12	5	2	2	0.2	0.2	NA	NA	1568	0.937
Utah	San Juan	Tin Cup Mes [14]	Ismay	69	15	9	3	1	0.5	1	0.4	NA	NA	1400	0.68
Aneth Platform Desert Creek Zone Subplay															
Arizona	Apache	Boundary Butte East [15]	Ismay-Desert Creek-Akah	70	4	2	0.8	0.3	0.2	8.2	13.8	1.0	0.1	871	0.778
Utah	San Juan	Akah [16]	Ismay-Desert Creek-Akah	57	6	NA	NA	NA	NA	13	18	NA	NA	863	NA
Utah	San Juan	Anido Creek	Ismay-Desert Creek	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Utah	San Juan	Bluff [4]	Desert Creek	75	14	5	2	1	0.5	2	0.4	Tr	0	1640	0.954
Utah	San Juan	Clay Hill [17]	Desert Creek	54	23	13	6	2	2	1	0.3	0	Tr	1636	0.970
Utah	San Juan	Desert Creek [4]	Desert Creek	65	18	9	4	2	0.6	3	0.1	Tr	0	1412	0.836
Utah	San Juan	Gothic Mesa	Desert Creek	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1150	NA
Utah	San Juan	Greater Aneth [4, 18, 19]	Desert Creek	62	18	11	5.5	2.5	<1	0	0.1	0	0	1450	NA
Utah	San Juan	Recapture Creek [19, 20]	Ismay-Desert Creek	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1425	0.834
Utah	San Juan	Runway [21]	Desert Creek	72	15	7	3	1	0.6	1.1	0.6	0	0	1366	0.779
Utah	San Juan	Tohonadla [4]	Ismay-Desert Creek-Akah	60	22	9	4	1	0.3	3	0.2	0.1	0	1449	0.861
Utah	San Juan	Turner Bluff	Desert Creek	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fractured Shale Subplay															
Utah	Grand	Long Canyon	Cane Creek shale	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Utah	Grand	Big Flat[22]	Cane Creek shale	67	NA	NA	NA	NA	AN	2.6	trace	NA	0	1471	0.860

NA = not available

[1]Scott (2003), [2]Matheny and Martin (1987), [3]Mickel (1978a), [4]Moore and Sigler (1987), [5]Martin (1983), [6]Oline (1996), [7]Wold (1978), [8]Spencer (1978), [9]Ross and Handley (1993), [10]Crawley-Stewart and Riley (1993a), [11]Crawley-Stewart and Riley (1993b), [12]Mickel (1978b), [13]Krivanek (1978), [14]Steele and White (1993), [15]Dunn (1978), [16]Riggs (1978), [17]Lehman (1983), [18]Moore and Hawks (1993), [19]Stowe (1972), [20]Scanlon and Wendling (1983), [21]Chidsey and others (1996a), [22]Grove and others (1993).

Table 10-5. Cumulative oil and gas production from vertical wells completed in the Cane Creek shale. Data from the Utah Division of Oil, Gas and Mining as of August 1, 2008. All locations are Salt Lake Base Line and Meridian (SLBL&M). Production is in barrels of oil (BO) and thousand cubic feet of gas (MCFG).

Field Name **Well Name** **Location**	**Completion Date**	**Current Status**	**Cumulative Production** **Oil** **Gas**
Bartlett Flat Field Big Flat 5 Section 27, T. 25 S., R. 19 E.	1961	Abandoned 1965	39,393 BO 22,051 MCFG
Unnamed Gold Bar 1 Section 29, T. 25 S., R. 20 E.	1982	Abandoned 1984	13,393 BO 14,800 MCFG
Unnamed Mathew Federal 1 Section 4, T. 26 S., R. 20 E.	1981	Abandoned 1982	1,343 BO 0 MCFG
Unnamed Skyline 1 Section 5, T. 26 S., R. 20 E.	1982	Abandoned 1982	675 BO 1,430 MCFG
Unnamed Skyline 8-44 Section 8, T. 26 S., R. 20 E.	1976	Abandoned 1976	507 BO 0 MCFG
Long Canyon Field Long Canyon 1 Section 9, T. 26 S., R. 20 E.	1962	Producing	1,087,375 BO 1,128,167 MCFG
Cane Creek Field MGM 2 Section 36, T. 26 S., R. 20 E.	1959	Abandoned 1969	1,887 BO 25,000 MCFG
Shafer Canyon Field Shafer 3 Section 4, T. 27 S., R. 20 E. USA 1 Section 6, T. 27 S., R. 20 E.	 1963 1962	 Abandoned 1963 Abandoned 1967	 1,325 BO 0 MCFG 66,231 BO 63,807 MCFG
Lion Mesa Field Lion Mesa 27-1A Section 27, T. 27 S., R. 21 E.	1980	Shut in	1,608 BO 0 MCFG
Wilson Canyon Field Chevron Federal 1 Section 24, T. 29 S., R. 23 E.	1968	Producing	98,544 BO 129,713 MCFG
TOTAL			1,312,281 BO 1,384,968 MCFG

Table 10-6. Cumulative oil and gas production from horizontal wells completed in the Cane Creek shale. Data from the Utah Division of Oil, Gas and Mining as of August 1, 2008. All locations are SLBL&M. Production is in barrels of oil (BO) and thousand cubic feet of gas (MCFG).

Field Name Well Name Location	Completion Date	Current Status	Cumulative Production Oil Gas
Hell Roaring Field Kane Springs Federal 10-1 Section 10, T. 25 S., R. 18 E.	1992	Producing	536,743 BO 497,672 MCFG
Wildcat Cane Creek Federal 7-1 Section 7, T. 25 S., R. 19 E.		Shut in	No production
Big Flat Kane Springs Federal 27-1 Section 27, T. 25 S., R. 19 E.	1991	Producing	426,879 BO 473,336 MCFG
Kane Springs Federal 25-19-34-1 Section 34, T. 25 S., R. 19 E.	1993	Producing	305,136 BO 258,329 MCFG
Cane Creek Federal 11-1 Section 11, T. 26 S., R. 19 E.	2002	Producing	18,944 BO 8,567 MCFG
Wildcat Kane Springs Federal 28-1 Section 28, T. 25 S., R. 19 E.	1992	Shut in	No production
Big Flat West Kane Springs Federal 20-1 Section 20, T. 26 S., R. 20 E.		Shut in	No production
Park Road Kane Springs Federal 19-1A Section 19, T. 26 S., R. 20 E.	1991	Producing	301,233 BO 288,611 MCFG
TOTAL			1,588,952 BO 1,526,515 MCFG

OUTCROP ANALOGS FOR MAJOR RESERVOIRS

CHAPTER 11
OUTCROP ANALOGS FOR MAJOR RESERVOIRS

Thomas C. Chidsey, Jr., Hellmut H. Doelling, Kevin McClure, Craig D. Morgan,
Douglas A. Sprinkel, and Grant C. Willis,
Utah Geological Survey

Introduction

Utah is unique in that representative outcrop analogs (depositional or structural) for each major oil play are present in or near the thrust belt, Paradox Basin, and Uinta Basin. Production-scale analogs provide an excellent view, often in 3D, of reservoir-facies characteristics, geometry, distribution, and nature of boundaries contributing to the overall heterogeneity of reservoir rocks. The specific objectives of this project are to: (1) increase understanding of vertical and lateral facies variations and relationships within major reservoirs; (2) describe the lithologic characteristics; (3) determine the morphology, internal geometries, and possible permeability and porosity distributions; and (4) identify potential impediments and barriers to fluid flow.

An outcrop-analog model, combined with the details of internal lithofacies characteristics, can be used as a "template" for evaluating data from conventional core, geophysical and petrophysical logs, and seismic surveys. When combined with subsurface geological and production data, the analog model will improve development drilling and production strategies, reservoir-simulation models, reserve calculations, and design and implementation of secondary/tertiary oil recovery programs and other best practices used in the oil fields of Utah and vicinity. Outcrop analogs for the major oil reservoirs in the thrust belt, Uinta Basin, and Paradox Basin are presented in the following sections.

Thrust Belt

Jurassic Nugget and Navajo Sandstone

Some of the best outcrop analogs to the Nugget Sandstone reservoirs in the southwest Wyoming and northern Utah thrust belt and the stratigraphically equivalent Navajo Sandstone reservoir in the central Utah thrust belt are found in southern Utah. The Navajo Sandstone is famous for its exposures in Zion National Park and Glen Canyon National Recreation Area in southern Utah (figure 11-1). Navajo dunes were straight-crested to sinuous, coalescing, transverse barchanoid ridges with slipfaces dipping toward the downwind direction (Picard, 1975). Regional analyses indicate paleocurrent and paleowind directions were dominantly from the north and northwest (Anderson and others, 2000; Chidsey and others, 2000a). Outcrops along the shores of Lake Powell in Glen Canyon National Recreation Area display classic eolian bedforms (Ahlbrandt and Frybreger, 1982) such as tabular planar, wedge planar, and large-scale trough cross-strata (figure 11-2). They occur in sets up to 25 feet (8 m) thick. Dips of cross-beds between set boundaries vary as much as 40 degrees from the nearly horizontal structural attitude of the formation in Glen Canyon National Recreation Area. Dune sand-flow toes often form tangential contacts of cross-beds with the lower bounding surfaces (Ahlbrandt and Frybreger, 1982). Dune lithofacies from the brink to the toe of the dune slipface consist of (1)

thin, reverse graded, tabular, pinstriped grainfall laminae, (2) thick, subgraded avalanche laminae, and (3) thin, tightly packed, reworked ripple strata at the dune toe (Lindquist, 1983). Wind ripples or high-index ripples are occasionally preserved on topset deposits. The south shore of Antelope Island in Lake Powell contains some of the best examples of soft-sediment deformation or contorted bedding in the Navajo. The contorted bedding is the result of slumping on the slopes of sand dunes before the sediments were lithified, possibly during earthquakes. Many of the tortuous and twisted beds have weathered in relief, forming eerie-looking outcrops (figure 11-3).

In addition to "seas" of wind-blown sand dunes, large deserts such as the Sahara and Gobi contain depositional interdune lithofacies, including playas and oases. An oasis is a vegetated area in desert regions where springs or lakes are present for relatively long periods of because the water table is close to the surface. A playa is a flat-floored bottom of an undrained desert valley that is only occasionally the site of shallow lakes. Within the Navajo Sandstone around Lake Powell in Glen Canyon National Recreation Area are many thin-bedded, lenticular limestone beds that are interpreted as interdune oasis deposits (Anderson and others, 2000; Chidsey and others, 2000a, 2000b). Shallow lacustrine limestone seems to be the most common. Oasis deposits are typically represented by light-gray, 5- to 10-foot-thick (2-3 m), thin and horizontally bedded limestone that commonly contains oscillation ripples and mudcracks (figure 11-4A and B). They generally pinch out over very short distances (tens of feet) (figure 11-4C), and can be observed on both sides of the narrower canyons (figure 11-5). Limestone beds in several Navajo outcrops have yielded fossil plants and invertebrates (Stokes, 1991; Santucci, 2000). Many limestone beds also contain cryptalgalaminites (algal laminae) most likely created by coccoid blue-green algal or cyanobacterial processes as organic mats and thrombolites (figures 11-4D and 11-6) (D.E. Eby, Eby Petrography & Consulting, Inc., written communication, 2003). Playas or mudflats (some with evaporite minerals) are also present in the Navajo around Lake Powell, represented by planar beds composed of mud, silt, and very fine grained sand.

Similar Navajo limestone beds along the Colorado River near Canyonlands National Park represent small freshwater lakes based on geochemical analysis (Gilland, 1979). Fresh ground water at a shallow depth had to persist for prolonged periods of time, perhaps many thousands of years, to allow the lake or pond deposits of these oases to develop (Stokes, 1991). The continuous supply of fresh water provided favorable environments for life and the deposition of carbonate rocks (figure 11-5). The Alashan area of the Gobi Desert contains a high water table producing similar lakes between massive dunes today (Webster, 2002).

Some Navajo interdunes were erosional (deflation) areas associated with running water, such as a wadi or desert wash (Chidsey and others, 2000a, 2000b). An ancient wadi deposit can be observed in the Navajo Sandstone in Rainbow Bridge National Monument, Utah (figure 11-1) and is represented by several dark, iron-stained channelform features present on the south side of Rainbow Bridge Canyon (figure 11-7A), a tributary canyon to Glen Canyon and the Colorado River. A wadi is a usually dry streambed or channel in a desert region. A few large blocks of a wadi deposit fell to the terrace bench, near the Rainbow Bridge viewing area, from a channel bed about 3 feet (1 m) thick about 50 feet (15 m) up the cliff. The deposit is a "pudding stone" consisting of tan to reddish-orange, rounded sandstone fragments or clasts, and gray to dark gray, subangular to subrounded dolomitic limestone clasts (figure 11-7B). Clasts vary from pea to small boulder sized. The matrix is medium- to coarse-grained sandstone cemented with iron-bearing quartz and minor calcite. The fallen blocks are horizontally

stratified and have some small-scale cross-beds. They contain rip-up clasts of lime muds; some imbricated rip-up clasts are inclined in the downstream direction. Additional wadi deposits are located in other parts of Rainbow Bridge Canyon and nearby Forbidding Canyon, and possibly belonged to the same ancient wadi system (figure 11-7C).

Navajo interdune lithofacies have significantly poorer reservoir characteristics than the dune lithofacies. Although interdune lithofacies are generally not as aerially extensive as the dune reservoir lithofacies above and below, they can compartmentalize a reservoir as observed in outcrops along the west flank of the San Rafael Swell (figure 11-8) (Dalrymple and Morris, 2007). Poorly developed interdune or wadi interdune lithofacies are not laterally extensive and are not effective barriers. These lithofacies have low permeability, giving them the potential to create baffles within a reservoir. Low porosity and permeable limestone of oasis deposits can create a significant barrier to fluid flow. From outcrop observations, oasis lithofacies form barriers if their lateral extent is within the limits of the structural closure of an oil field; the reservoir will be partitioned. If the interdune lithofacies only partially covers the structure, then it will act as a baffle and fluids can move around the impermeable layers (Dalrymple and Morris, 2007).

Identification and correlation of dune/interdune lithofacies in individual Nugget reservoirs in the thrust belt is critical to understanding their effects on production rates and paths of petroleum movement (Lindquist, 1983). Avalanche laminae, soft-sediment deformation, and other depositional features can also result in significant reservoir heterogeneity, even within the dune lithofacies.

Jurassic Twin Creek Limestone

The best outcrop analogs of the Twin Creek Limestone reservoir are found about 20 miles (32 km) west of Anschutz Ranch field at Devils Slide on the Crawford thrust plate (figures 11-9 and 11-10), and 9 miles (15 km) southwest of Lodgepole field near the town of Peoa, Utah, on the Absaroka thrust plate (?) (figures 11-9 and 11-11). Both sites are located along highways; however, the Devils Slide outcrop is within a large cement quarry operated by Holcim (U.S.) Inc. and permission must be obtained to gain access. All seven formal members are recognized in these outcrops (figure 11-12).

Although the sections are faulted and display some bed repetition, portions, or the entire thickness, of all seven Twin Creek members are exposed at the Devils Slide and Peoa sites. Sections at both sites were measured and described. The Twin Creek at Devils Slide strikes generally parallel to the leading edge of the Crawford thrust (north-northeast) with beds dipping greater than 65° east to overturned to the west; several small back thrusts are present (figure 11-10). The Twin Creek at Peoa strikes generally parallel to the leading edge of the Absaroka thrust (east-northeast) and the North Flank fault of the Uinta uplift, with beds dipping more than 70° north-northwest (figure 11-11).

These sections display the same reservoir heterogeneity characteristics that affect production or provide horizontal drilling targets in the Twin Creek Limestone productive fields. This heterogeneity, created by fracturing (or the lack thereof), and lithologic variation provide both the reservoir storage capacity and/or seals (barriers) within the traps. Fractures in the Twin Creek, as is the case with other sedimentary rocks, generally have a consistent geometry with respect to the three principal stresses (σ_1 = greatest, σ_2 = intermediate, σ_3 = least principal compressive effective stress) at the time of the fracture development (Stearns, 1984). Fractures

near faults depict the stress field responsible for the fault. Fractures in folds are genetically related to the folding process itself, not a consequence of the regional stress field that produced the folding. Parallel fracture sets are commonly present, and their geometry results from compression and extension (when σ_2 is either parallel or normal to bedding) associated with the fold development as well as the type of sedimentary rock involved (Stearns, 1984). Four different orientations of the three principal stresses are recognized in folds (figure 11-13): (1) σ_1 and σ_3 in the bedding plane, σ_1 parallel to the dip direction, (2) σ_1 and σ_3 in the bedding plane, σ_1 parallel to the strike direction, (3) σ_2 parallel to bedding strike, σ_1 normal to bedding, and (4) σ_2 parallel to bedding strike, σ_3 normal to bedding. These four orientations produce 12 possible fracture planes – two shear and one extension for each orientation (Stearns, 1984).

Both faulting and folding account for outcrop orientations at the Devils Slide and Peoa sites. Thus, fractures as described above have likely been generated by these structural events. The general fracture pattern observed in the rocks at these locations can be applied to planning directions of horizontal wells proposed in the Twin Creek Limestone play.

The following sections are general outcrop descriptions of the lithology, sedimentary structures, and fracture patterns in each member of the Twin Creek Limestone, in ascending order, compiled from the Devils Slide and Peoa field observations and measured stratigraphic sections. Detailed descriptions, regional correlation, fossils, and depositional environments of these members are included in Imlay (1967).

Gypsum Spring Member: The Gypsum Spring Member consists of shale (covered) and a basal pebble-rich to coarse-grained sandstone. Bedding is thick to medium, and tabular. The sandstone is composed of rounded to subrounded frosted grains derived from the underlying Nugget Sandstone.

Sliderock Member: The Sliderock Member is composed of dark gray, micritic limestone. It is medium to thick bedded, often forming a resistant ledge with some thin laminations and silt partings. Fractures are abundant and commonly closely spaced. Some less resistant (highly fractured) units weather into slopes littered with plates, chips, and pencils.

Rich Member: Devils Slide is composed of resistant and non-resistant units of the Rich Member. The Rich consists of dense, finely crystalline to micritic limestone with some sandy to calcarenite units forming the lower and upper resistant ledges of Devils Slide, respectively (figure 11-14). Red-brown, calcareous siltstone forms the non-resistant center of Devils Slide. Laminated siltstone partings and sandy limestone are also found in several units of the Rich. Bedding is thick to thin with occasional planar cross-beds and current ripples (figure 11-15A).

Rhombic fracture patterns are developed on bedding planes (figures 11-15B and 11-15C), likely the result of σ_1 and σ_3 in the bedding plane, with σ_1 parallel to the dip direction (set 1 on figure 11-13). Weathering along closely spaced rectilinear fractures within dense homogeneous limestone beds yields abundant pencils and plates (figures 11-15D and 11-15E). Two sets of rhombic fractures, low angle and high angle in relationship to bedding, and another set parallel to bedding are apparent in the outcrop shown on figure 11-15D. As shown on figure 11-13, these fractures correspond to both set 3, where σ_2 is parallel to bedding strike and σ_1 is normal to bedding, and set 4, where σ_2 is parallel to bedding strike and σ_3 is normal to bedding.

There is little to no primary porosity within the crystalline to micritic limestone units of the Rich. However, the contact with the basal siltstone unit (where fractures are sealed) of the

overlying Boundary Ridge Member sets up the Rich for hydrocarbon trapping and production (figure 11-15F).

Boundary Ridge Member: The Boundary Ridge Member is composed of dark, red-brown siltstone to claystone, gray-green, micritic limestone, and very fine to fine-grained, well-sorted, gray sandstone and calcarenite. Bedding is thin to thick, with some contorted bedding (within lensoidal-shaped bodies), cross-bedding, parallel lamina, and occasional ripples. Some units contain peloids and possible fossil hash.

Watton Canyon Member: The Watton Canyon Member is composed of dark to medium gray, dense, resistant, finely crystalline to micritic limestone. Bedding is thin to thick, with large-scale current ripples and silty lamina that exhibit cross-bedding in some units. Limestones occasionally contain stylolites, oolites, peloids, and fossils (primarily pelecypods).

Rectilinear fracturing is pervasive and includes both open and calcite-filled fractures (figure 11-16A through 11-16D); calcite-filled vugs are also present in some beds. Rhombic fracture patterns on bedding planes (figures 11-16A through 11-16D) formed from stresses with σ_1 and σ_3 in the bedding plane and with σ_1 parallel to the dip direction (set 1 on figure 11-13), and/or from σ_1 and σ_3 in the bedding plane, and σ_1 parallel to the strike direction (set 2 on figure 11-13). Fractures also occur parallel to strike on the bedding planes as shown in figures 11-16A and 11-16D, and correspond to set 3 on figure 11-13, where σ_2 is parallel to bedding strike and σ_1 is normal to bedding. The differing fracture patterns formed as the stress fields changed with folding and faulting of the stratigraphic sections over time.

Like the Rich Member, the uppermost fractured limestone unit of the Watton Canyon Member is sealed, in this case by the argillaceous basal unit of the overlying Leeds Creek Member (figure 11-16E). Reservoir heterogeneity within the Watton Canyon itself is observed in outcrop, where thin-bedded siltstones create additional barriers or baffles to fluid flow (figure 11-16F).

Leeds Creek Member: The Leeds Creek Member is composed of interbedded gray, laminated, fissile to dense, microcrystalline limestone, red-brown siltstone to gray-green calcareous mudstone, and very fine grained, well-sorted sandstone and calcarenite. Bedding is thin to thick, weathering into small chips, thick pencils, and plates. Some limestone units contain peloids or coated grains. Argillaceous or clay-rich units may contain sandy interference ripples and cross-beds. Fractures and vugs tend to be calcite filled; calcite veinlets may also be present.

Giraffe Creek Member: The Giraffe Creek Member is composed of interbedded moderately resistant, gray, medium crystalline limestone, calcareous siltstone, and fine- to medium-grained calcarenite. Some units contain oolites, and coated and lithic grains. Cross-bedding and current and interference ripples are also common; a few silty beds are lensoid. At the Devils Slide section, a rectilinear fracture pattern at the top of the Giraffe Creek is marked by a bedding-parallel back thrust (figure 11-10).

Uinta Basin

Deep Uinta Basin Overpressured Continuous Play

The depositional environments of the Tertiary Green River and Colton reservoirs in the Altamont-Bluebell-Cedar Rim field area of the DUBOC play are, from north to south (proximal to distal): alluvial fans to fan deltas, and marginal lacustrine to open lacustrine. Sediment source was the Uinta uplift north of the field area. The Green River and Colton do not crop out north of the field area, therefore a similar tectonic setting along the western arm of Lake Uinta is presented as a reservoir analog (figure 11-17).

No single outcrop or outcrop belt provides a view of the complete proximal to distal facies changes in the Flagstaff Limestone (equivalent to the Flagstaff Member of the Green River Formation) as the depositional environment of this unit changes from fan deltas to open lacustrine. Three different locations in Sevier and Sanpete Counties provide good outcrop examples of the various facies shed off the western highlands into Lake Uinta (figure 11-18). South Cedar Ridge Canyon contains exposures of proximal facies consisting of interbedded conglomerate, sandstone, and siltstone that were commonly deposited in water as fan deltas extending into Lake Uinta (figures 11-19 and 11-20). Exposures of medial facies in Lone Cedar Canyon have been described as interbedded shale, sandstone, and limestone deposited in a marginal-lacustrine environment. Another good exposure of the Flagstaff that is more accessible is in Price River Canyon (figure 11-21); here the medial facies of the Flagstaff is composed of open-lacustrine shale and limestone. Distal Flagstaff facies are also exposed at Musinia Peak on the Gunnison Plateau and in Manti Canyon (figure 11-22) on the Wasatch Plateau.

Conventional Northern Uinta Basin Play

An outcrop analog for the major oil reservoirs in the Green River Formation in the CNUB play is available along Raven Ridge in the northeastern Uinta Basin (figure 11-23). The Raven Ridge outcrop belt is a 20-mile-long (32 km), dip-oblique transect. Shoreline trends in the Green River are generally east-west and therefore the northwest to southeast outcrop exhibits about 14 miles (23 km) of landward to lakeward facies transitions (Borer, 2003). Several locations offer excellent exposures of shoreline deposits (figure 11-24) that serve as reservoirs, and bay-fill deposits (figure 11-25) that provide organic-rich source rocks for the play. Borer and McPherson (1998), and Borer (2003) have done extensive work on the Raven Ridge outcrops and presented their results in two unpublished field trip guidebooks. Oil Gully is just one of their measured sections, although there are numerous other excellent exposures along Raven Ridge described by Borer and McPherson (1998), and Borer (2003). The following description of Oil Gully is taken largely from their work.

Oil Gully, named for the many tar sands in the exposed rocks, is a good outcrop analog for the reservoirs at Red Wash field. Borer (2003) measured 300 feet (100 m) of section in Oil Gully, which contains numerous depositional rise-to-fall cycles (figure 11-26). Some of the features that Borer describes at Oil Gully include landward-migrating bar forms that develop transgressive caps; gravity flow cycles; and lagoonal and high-energy, upper shoreface facies.

Conventional Southern Uinta Basin Play

Outcrop analogs for the major oil reservoirs in the Green River Formation in the CSUB play are presented in the following sections. The Green River Formation is well exposed in Willow Creek, Indian, and Nine Mile Canyons in the south-central Uinta Basin (figure 11-27). Morgan (2003a) presented road logs describing the exposures in these canyons. The exposures in Willow Creek Canyon are generally limited to road cuts, which provide easy access but limited lateral extent. Indian Canyon provides an excellent view of the upper and saline members of the Green River. Nine Mile Canyon has more than 30 miles (50 km) of continuous exposures of the Green River Formation.

Uteland Butte interval: The Uteland Butte interval is exposed at the junction of Minnie Maud and Nine Mile Canyons (figure 11-28). At this location, the Uteland Butte interval overlies the Colton Formation and is overlain by a tongue of the Colton (figure 11-29). Little (1988) described the interval as dolomitized ostracod and pellet grainstone and packstone deposited in shallow-water mudflats; pelecypod-gastropod sandy grainstone, commonly interbedded with silty claystone or carbonate mudstone that was deposited in shallow open-lacustrine environments; and dark-gray kerogen-rich carbonates that were deposited in deeper offshore environments (figures 11-30 and 11-31). The reservoir rock is thin grainstones and fractured carbonates.

Castle Peak interval: The Castle Peak interval is exposed in the western portion of Nine Mile Canyon (figure 11-32). At this location, the interval overlies the previously mentioned Colton tongue and is overlain by the Travis interval. The top of the Castle Peak is picked at the top of the carbonate marker bed of Ryder and others (1976). At this location, Remy (1992) measured 443 feet (135 m) of interbedded carbonate, shale, and sandstone (figure 11-33). The primary reservoir rocks are the channel sandstone beds described as generally having a sharp base with some rip-up clasts and trough cross-beds, fining upwards from medium to fine grained, with low-angle to planar bedding. The sandstone beds are typically isolated channel deposits (figure 11-34).

Travis, Monument Butte, and Beluga intervals: The primary reservoirs for the Travis interval are turbidite and gravity-flow deposits, which have not been identified in outcrop. The secondary reservoirs in the Travis interval and the primary reservoirs in the Monument Butte and Beluga intervals are distributary-channel deposits. The Monument Butte interval typically contains amalgamated stacked channel deposits, whereas in the Travis and Beluga intervals, the distributary channels are generally isolated individual channels. Although the volume of reservoir rock varies between the intervals, the depositional and petrophysical properties are similar. Therefore, one location is described as an outcrop analog for the Travis (secondary reservoir), Monument Butte, and Beluga intervals.

We studied the outcrops from Petes Canyon to Gate Canyon in Nine Mile Canyon (figure 11-35) as an analog to the oil reservoirs in the Monument Butte and adjacent oil fields (Morgan and others, 2003). These outcrops, termed the Nutter's Ranch study site because of its proximity to the historical Nutter Ranch house, lie within section 32, T. 11 S., R. 15 E. (Salt Lake Base Line and Meridian [SLBL&M]), in Duchesne County, and contain a well-exposed,

large-scale depositional cycle (table 11-1). The complete sequence exposed at the Nutter's Ranch study site was described by Remy (1992).

Detailed examination of the outcrop identified the potential heterogeneity that can exist between wells in two dimensions (as well as over a square mile), as an analogy to a typical water-flood unit in the Monument Butte area to the north. Wells in the Monument Butte area are drilled on 40-acre (16.2-ha) spacing resulting in about 1320 feet (400 m) between wells. The typical water-flood unit in the Monument Butte area is a square mile (one section) or larger, with wells in the center of every 40-acre (16.2-ha) lot, or 16 wells per section. The wells are initially completed as oil wells, but after they have all been drilled and the primary production drops below a minimum level, every other well is converted to a water injection well, resulting in eight producing and eight injection wells per section.

The Nutter's Ranch study site includes portions of Petes Canyon and Gate Canyon, and the portion of Nine Mile Canyon between these canyons. The exposure is about 2000 feet (600 m) in the east-to-west direction in Nine Mile Canyon and in the north-to-south direction in Gate Canyon, and about 4200 feet (1300 m) in the north-to-south direction in Petes Canyon. The stratigraphic interval studied is slightly more than 100 feet (30 m) thick, and is bounded by carbonate beds at the base (M8) and at the top (M9) (figure 11-36). Eight sections were measured and described, and gamma-ray data were gathered from five of the sections. To aid in the stratigraphic interpretation, the site was photographed from the canyon walls opposite the study site, and photomontages were compiled. The photomontages were used to map out individual beds and their relationships (Morgan and others, 1999, 2003).

Two imaginary wells along the Nine Mile Canyon portion of the Nutter's Ranch study site are shown 1320 feet (400 m) apart to illustrate the type of reservoir heterogeneity that could exist between two wells drilled on 40-acre (16.2-ha) spacing units (figures 11-37 and 11-38). Both of the imaginary wells encounter a carbonate bed above (M9) and below (M8), and two reservoir-quality sandstone beds. Well logs could be interpreted to show excellent correlation of the carbonate and sandstone beds (figure 11-37). As a result, good lateral continuity of the sandstone beds would be expected. However, contrary to the interpretation in figure 11-37, the upper sandstone in the two wells is actually two separate deposits (Ss-e and Ss-f) that would probably have very poor to no fluid flow between them (figure 11-38). Ss-e is an amalgamated channel deposit that has good reservoir potential, but Ss-f is a crevasse splay deposit that has complex internal heterogeneity in the proximal channel facies and high clay content in the distal bar facies. As seen on outcrop, the lower sandstone (Ss-c) is the same bed in both of the wells, but has been locally cut out by the overlying channel sandstone (Ss-d). In some places Ss-e has incised down to Ss-c, creating a potential for fluid-flow communication between the two sandstone beds. Ss-d nearly cuts out Ss-c and is a potential reservoir that is not penetrated by either of the imaginary wells. Ss-a is laterally continuous but thin and has poor porosity and permeability due to abundant clay. Ss-b is a very narrow bed that would rarely be penetrated by a well with 40-acre (16.2-ha) spacing and would probably not have sufficient storage capacity to be an economical oil reservoir.

The thickness of the three potential reservoir sandstone beds (Ss-c, Ss-d, and Ss-e) was determined by direct measurement and by extrapolating between the measured sections using photomontages. The sandstone thickness values and associated Universal Transverse Mercator (UTM) coordinates were entered into an Arcview® database. The section that contains the study site (section 32, T. 11 S., R. 15 E., SLBL) was divided into 40-acre (16.2-ha) lots, and the UTM coordinates for the center of each lot were determined and entered into the database as an oil

well location with a well number (figure 11-39). Every other well was designated as a water injection well, the typical pattern for a water flood in the Monument Butte area. The imaginary wells in the two-dimensional model were located directly along the outcrop. The imaginary well locations for the three-dimensional model are the centers of 40-acre (16.2-ha) lots, and are not the same as the two-dimensional model imaginary well locations.

Sandstone thickness maps, based on the outcrop values, were constructed using Arcview Spatial Analyst® and by hand contouring. Sandstone thickness for each of the three beds was assigned to the imaginary wells based on the draft thickness maps and entered into the database. Final sandstone thickness maps for the three beds were generated using Arcview Spatial Analyst. Ss-c (figure 11-40) is the most laterally extensive of the three potential reservoir beds and ranges from less than 5 feet to more than 55 feet thick (16-180 m). The bed is laterally extensive because it overlies a muddy limestone that it could not cut through, causing the channel to migrate back and forth resulting in laterally extensive deposits. The alternating pattern of producer well and injector well locations would have some success in this bed. However, the thickest portion of this bed, located in the northwest quarter of the section, is not penetrated and would be produced by wells on the flanks of the sandstone trend. Ss-d, which was shown in the two-dimensional model to nearly cut out Ss-c, isolates a portion of Ss-c in the center of the easternmost portion of the section. While up to 30 feet thick (98 m), Ss-d is narrow (a few meters), has a very limited extent in the study area (figure 11-41), and would contain a very limited volume of oil. The 8-32 production well and the 9-32 injection well penetrate Ss-d, but not along the axis of the sandstone bed. As a result, only a small portion of the limited oil volume of Ss-d would be produced. Ss-e has moderate lateral extent (up to 2500 feet [8202 m]) across in the study site but is generally thicker (up to 55 feet thick [180 m]), where present, than Ss-c (figure 11-42). The alternating pattern of production and injection wells appears to be moderately effective in draining Ss-e. Some of the thickest sandstone is between injection well 7-32 and production well 8-32. Production well 8-32 penetrates only 4 feet (1.2 m) of Ss-e; as a result, it would probably be a very poor producer because most of the oil contained in the thick sandstone between the two wells would remain in the ground.

Duchesne interval fractured shale/marlstone: The Duchesne interval is defined as from MGR 18 to the top of the Green River Formation, and includes the upper portion of the middle member and all of the upper and saline members. The interval represents the maximum rise and eventual waning stages of ancient Lake Uinta and is well exposed in Indian Canyon south of the town of Duchesne (figure 11-27). Fractures can be observed in the Green River Formation in Indian Canyon and throughout the surface exposures in the Duchesne field along the Duchesne fault zone. Any fractured outcrop (sandstones, shale, and marlstones) in the upper and saline members can be considered a reservoir analog, but a person can take a hike to the abandoned wurtzillite mine in Indian Canyon to observe fractures containing hydrocarbons. Wurtzillite is a solid hydrocarbon that was mined from the saline member (?). The trail begins 16.1 miles (25.9 km) south on U.S. Highway 33 from the junction of U.S. Highway 33 and U.S. Highway 40 in the town of Duchesne, 0.4 miles (0.6 km) past the Forest Service sign.

Paradox Basin

Mississippian Leadville Limestone

South Flank of the Uinta Mountains, Utah: Although not exposed in southeastern Utah, Mississippian rocks equivalent to the Leadville Limestone outcrop in the northern and western parts of the state (figure 11-43). These formations include the Madison, Gardison, and Deseret Limestones (figure 11-44), and have generally the same characteristics as the Leadville (if the Delle Phosphatic Member is present, the formation is the equivalent Deseret Limestone [Hintze, 1993]). They provide production-scale analogs of the facies characteristics, geometry, distribution, and the nature of boundaries contributing to the overall heterogeneity of Leadville reservoir rocks. Excellent examples of Leadville-equivalent rocks (Madison Limestone) are found along the south flank of the Uinta Mountains where they are up to 600 feet (200 m) thick (figure 11-43).

The Madison Limestone is mostly light- to dark-gray, fine- to coarse-crystalline, cherty limestone (figure 11-45A). Dolomitic units are gray to tan, sucrosic to crystalline, and medium bedded with occasional silty partings; both limestone and dolomite are the prime reservoir lithologies for the Leadville Limestone. The Madison is generally thick to massive and unevenly bedded, forming vertical cliffs and dip slopes. Fossils include corals, brachiopods, crinoids, pelecypods, and gastropods (Rowley and Hansen, 1979); however, fossils are relatively rare in some areas. Chert is typically light gray, forming lenses and nodules. In the Whiterocks Canyon area (figure 11-43), the Madison contains some thin-bedded, tan, calcareous, fine- to medium-grained sandstone (Kinney, 1955).

The Madison, Gardison, and Deseret Limestones commonly contain numerous caverns, sinkholes, and local zones of breccia (due to either collapse associated with karstification or natural hydrofracturing) and vugs (figures 11-44, 11-45B, and 11-45C). Stylolites, jointing, and fractures are also present creating rock sections with high heterogeneity (figures 11-45A, 11-45B, 11-45D, and 11-45E). Possible buildups or oolitic shoals are found in the Madison Limestone in Dry Fork Canyon (figures 11-43 and 11-45F). Brecciation associated with hydrothermal events, fracturing, and dissolution enhance reservoir quality in the Leadville Limestone.

Marble Canyon, Grand Canyon National Park, Arizona: The Mississippian (upper Kinderhookian through lower Meramecian) Redwall Limestone in Grand Canyon National Park forms a prominent and spectacular cliff over 500 feet (170 m) in height (figures 11-46 and 11-47). It is stratigraphically equivalent to the Leadville Limestone reservoir and provides an excellent outcrop analog. The Marble Canyon area is the best place in the park to observe the stratigraphy, depositional environments, fracturing, and karst-type features of the Redwall as the Colorado River cuts down section through the entire formation (figures 11-46 and 11-47). However, access requires either guided river trips or special scientific permits from the National Park Service.

The Redwall Limestone is divided into four members based on distinct lithologic variations (McKee, 1969; McKee and Gutschick, 1969) in ascending order: the Whitmore Wash, Thunder Springs, Mooney Falls, and Horseshoe Mesa Members (figure 11-48). The Whitmore Wash is a fine-grained dolomite in Marble Canyon with a thickness up to 100 feet (30 m). The Thunder Springs contains thin beds of dolomite and elongate lenses of chert; the member is

nearly 90 feet (27 m) thick. The Mooney Falls is nearly 220 feet (67 m) thick with massive bedding (3 to 20 feet [1-6 m] in thickness) composed of pure limestone that is free of terrigenous material (less than 1%) and locally dolomitic. The Horseshoe Mesa is the thinnest member, about 35 to 125 feet (11-38 m), containing thin limestone beds and chert lenses that form receding ledges (Hamblin and Rigby, 1968; McKee, 1969). The Whitmore Wash and Horseshoe Mesa represent the best reservoir analog units while the Thunder Springs represents the worst reservoir analog unit.

The most common lithology of the Redwall Limestone consists of peloidal, skeletal, and oolitic grainstone, packstone, and wackestone; rudstone and floatstone are also present. An open-marine facies is represented by corals, brachiopods, foraminifers, and crinoids (figure 11-49A). Other common fauna include bryozoans, pelecypods, cephalopods, and gastropods. Algae, trilobites, ostracods, and fish are present in some Redwall zones (McKee, 1969; McKee and Gutschick, 1969). Several carbonate buildups are observed in the lower half of the Redwall such as shoals or banks of cross-bedded crinoid debris (encrinites) (figure 11-49B). Other buildups may indicate a Waulsortian-type facies (figure 11-49C) consisting of bands of encrinite, containing fenestrate bryozoan, interbedded with chert. With good porosity/permeability development encrinites and Waulsortian buildups represent the best reservoir analog units while low porosity/permeability open marine packstone and wackestone represent the worst reservoir analog units.

Mudstones appear as microcrystalline and cryptocrystalline limestone. Most dolomite zones form early as sedimentary dolomite in nearshore environments (McKee, 1969; MeKee and Gutschick, 1969). The pure limestone of the Mooney Falls Member likely formed in a broad, shallow, quiet sea far from terrigenous deposition associated with distant shorelines (Hamblin and Rigby, 1968).

Fracturing is present in the Redwall Limestone, especially in the upper members. It is best expressed as closely spaced, vertical fractures throughout thin to medium thick beds or as swarms associated with large and small faults (figure 11-49D) and collapse features. Possible breccia pipes are also observed in the Redwall and may be related to past hydrothermal activity (figure 11-49E). These features enhance reservoir quality.

The contact between the Redwall Limestone and overlying Pennsylvanian (Morrowan) Supai Group is marked by a major unconformity—upper Meramecian and Chesterian rocks are absent (McKee, 1969; Hintze, 1993). This unconformity formed karst topography which has many expressions in Marble Canyon. These include a surface with relief up to 40 feet (12 m) along the top of the Redwall, carbonate breccia-filled sinkholes (figure 11-50A) and solution channels, transported gravel within channels, and abundant caverns and springs. Terra rosa (cave fill) (figure 11-50B), in-place cave perils (figure 11-50C), and collapse features also provide evidence for filled-in caves and karst topography near the top of the Redwall. However, hundreds of caves, filled or partially filled with collapse debris (figure 11-50D), and springs (figure 11-50E) are exposed throughout the Redwall cliffs. Controls on these features are vertical joints, fractures, and selected bedding planes rather than the unconformity at the top of the Redwall (Hamblin and Rigby, 1968). Karst features also can enhance reservoir quality.

Pennsylvanian Paradox Formation

Carbonate buildups exposed in outcrops of the Paradox Formation along the San Juan River of southeastern Utah provide production-scale analogs of reservoir-facies characteristics,

geometry, distribution, and the nature of boundaries contributing to the overall heterogeneity of these rocks. Algal buildups in the Ismay zone are exposed at river level 10 river miles (16 km) east of Mexican Hat, Utah, with some of the best examples in the Eight-Foot Rapid area (figure 11-51). High-resolution, outcrop-based sequence-stratigraphic analysis has been conducted on these rocks by Goldhammer and others (1991, 1994), Simo and others (1994), Best and others (1995), Weber and others (1995a, 1995b), Gianniny and Simo (1996), and Grammar and others (1996). Ten river miles (16 km) west of Mexican Hat, over 1300 feet (400 m) of Pennsylvanian rocks, including almost the entire Paradox Formation, is exposed through the famous Goosenecks of the San Juan River (figures 11-51 and 11-52A) and along the Honaker Trail, which provides access to the river from the canyon rim (figures 11-51 and 11-52B). The Honaker Trail section has been extensively studied by Pray and Wray (1963), Wengerd (1963), Weber and others (1995a), Stevenson (2000), Ritter and others (2002), and many other workers.

Eight-Foot Rapid area, San Juan River: Phylloid-algal buildups of the Ismay zone exposed in the Eight-Foot Rapid area were deposited in northwest-trending elongate banks on a shallow carbonate shelf. The Ismay zone is divided into two intervals: the lower Ismay, which consists of a single, thick, shoaling-upward carbonate sequence, and the upper Ismay, which consists of three or more thinner, shoaling-upward, carbonate and carbonate-evaporite cycles.

Recognizing the morphologic variations in this area is critical to understanding controls on deposition. The following terms distinguish buildup geometry (Brinton, 1986). These are shown schematically in figures 11-53 and 11-54.

> Algal bank: The massive, lenticular, biostromal algal buildups, 30 to 40 feet (10-13 m) thick, exposed for several miles along the walls of San Juan Canyon.
>
> Interbank: The channel-like feature that separates, or bisects, algal banks.
>
> Algal mound: Secondary, ridge-and-swale or wave-form-like features that define the upper surfaces of the algal banks and impart the wavy topography that characterizes outcrops.
>
> Intermound: The shallow trough region between algal-mound crests.

The lower Ismay zone algal banks or buildups exposed along the San Juan River appear as flat-bottomed, convex-upward lenticular bioherms with undulating, wave-like upper surfaces and relief as great as 50 feet (15 m) (figure 11-55). The most distinctive feature of buildups and adjacent facies is the undulatory or ridge-and-swale upper surface of the algal banks. The wavy topographic features (mounds and intermounds) extend for miles along the walls of the canyon, displaying regular wavelengths (150 to 200 feet [46-61 m]) and amplitudes (10 to 20 feet [3-6 m]). Mounds appear to be superimposed on the larger-scale algal banks whose length/width ratios are more characteristic of biostromes (Brinton, 1986).

Cyclic sedimentation is recorded by four dominant lithofacies recognized in a single, shoaling-upward sequence (figure 11-56): (1) substrate carbonate, (2) phylloid algal, (3) intermound, and (4) skeletal capping (Brinton, 1986; Grammar and others, 1996). An outcrop in the Eight-Foot Rapid area displaying these and additional lithofacies was selected for detailed study (figure 11-57A) (Chidsey and others, 1996d). The phylloid algal and skeletal capping

lithofacies represent the best reservoir analog units while the substrate carbonate and intermound lithofacies represent the worst reservoir analog units.

The Eight-Foot Rapid study site is interpreted as consisting of three principal reservoir features: (1) a phylloid-algal mound with grainstone buildups deposited at or near sea level, (2) a "reef wall" that formed in a higher energy, more marginal setting than the mound, and (3) a carbonate detrital wedge and fan consisting of shelf debris. Figure 11-58 is a schematic block diagram illustrating hypothetical lithofacies relationships. This interpretation is not only based on observations made at the outcrop, but also incorporates subsurface core data that are discussed in Chidsey and others (1996b).

Bafflestone and *Chaetetes*- and rugose-coral-bearing grainstone and packstone textures observed in the northern part of the Eight-Foot Rapid complex comprise the main phylloid-algal mound (figure 11-57B). A flooding surface recognized on top of the buildup and probable low-permeability lithotypes (packstone and cementstone) within the buildup might act as barriers or baffles to fluid flow in the subsurface. The Eight-Foot Rapid outcrop appears to be only a portion of a larger algal-bank complex, or one of a series observed in San Juan Canyon. Although not documented at this outcrop, observations from cores in other areas in the subsurface suggest an interior-lagoon and other associated lithofacies likely formed to the west as part of this complex (Chidsey and others, 1996b).

The rudstone, cementstone, and lumpstone depositional textures represent deposits that were part of, or near, what might be interpreted as a "reef wall" (figure 11-58). The presence of internal sediments in these rocks indicates an influx of mud during storms, or mud routinely distributed by stronger currents. The reef wall records deposition and intense sea-floor cementation as a result of reflux of large pore volumes of water through sediments occupying a high-energy setting that is marginal between shallow-shelf and deeper, open-marine conditions. The reef wall may have served as a barrier behind which algal buildups could develop and thrive in a more protected setting that facilitated preservation of primary shelter porosity. The presence of reef-wall lithofacies in a well core might serve as a proximity indicator for a more prospective algal-buildup drilling target. Examples of this relationship have been observed in the Blue Hogan and Brown Hogan fields to the southwest of the Greater Aneth field (figure 10-4) (Chidsey and others, 1996b).

An intermound trough in the center of a mound could represent a tidal channel flowing across the reef wall (figure 11-58). Material shed from the mound and reef wall was subsequently carried through the tidal channel and might have been deposited as a detrital wedge or fan on open-marine carbonate muds. These features are recorded by the grainstone and transported material observed on the east side of the outcrop complex. Coralline-algal buildups may have also developed near the carbonate detrital fan but were not observed at this locality in the canyon.

Reservoir-quality porosity may have developed in troughs, detrital wedges, and fans identified from core and facies mapping. If these types of deposits are in communication with mound-reservoir lithofacies in the subsurface, they could serve as conduits facilitating sweep efficiency in secondary/tertiary recovery projects. However, the relatively small size and the abundance of intermound troughs over short distances, as observed along the river, suggests caution should be used when correlating these lithofacies between development wells. Lithofacies that appear correlative and connected from one well to another may actually be separated by low-permeability lithofacies which inhibit flow and decrease production potential.

Honaker Trail and The Goosenecks: The Paradox Formation section along the Honaker Trail includes both the Ismay and Desert Creek zones, and the Akah and Barker Creek (at river level) zones as well. The Horn Point marker bed defines the top of the lower Ismay zone. Ritter and others (2002) have identified 30 high-frequency cycles or 5th-order parasequences (Goldhammer and others, 1991) from the Horn Point to the bottom of the section based on conodont sequence biostratigraphy. These cycles are 6 to 21 feet (2-7 m) thick and grade from deeper-water sediments at the base to subtidal and shoaling carbonates at the top (Ritter and others, 2002).

The top of the Horn Point is a flooding surface (figure 11-59) representing a 4^{th}-order sequence boundary indicated here by (1) evidence of subaerial exposure, (2) regionally traceable surfaces, and (3) the presence of deeper-water black shales at the contact, in this case the Hovenweep shale above the Horn Point (Goldhammer and others, 1991). This type of surface or sequence boundary, as well as parasequence boundaries (also flooding surfaces [figure 11-60]), is a time-correlative marker in the subsurface. If these surfaces are not recognized and the intervals erroneously correlated lithostratigraphically, the result might be failure to recognize significant fluid-flow barriers, and misinterpretation of reservoir facies geometries and distributions. These surfaces must be recognized in conventional core and/or geophysical logs in order to accurately predict the distribution and continuity of reservoirs (Weber and others, 1995a, 1995b).

The Paradox Formation along the Honaker Trail (Horn Point marker bed of the lower Ismay zone to the base of the section in the Barker Creek zone) displays most of the major lithofacies associated with carbonate buildups observed in the formation at Eight-Foot Rapid. Carbonate fabrics, from deepest to shallowest, include shaley lime mudstone, sponge spicule-bearing wackestone, skeletal (mainly crinoidal and phylloid-algal) and peloidal wackestone to packstone, and oolitic grainstone (Ritter and others, 2002). An unusual cross-bedded, 5-foot-thick (2-m) quartz sandstone unit (figure 11-61) is present near the top of the lower Ismay above a fossiliferous wackestone. Similar cross-bedded sandstone units have been recognized by Eby and others (2003) in core from wells in the Blanding sub-basin. Large chert nodules, presumably derived from sponge spicules, are common in laminated, deeper-water limestone (figure 11-62). *Chaetetes* are also commonly associated with fossiliferous wackestone in the skeletal-capping facies above the phylloid-algal facies (figure 11-63). Peloidal and oolitic grainstone in the cap and intermound facies display well-developed cross-bedding (figure 11-64).

Distinct phylloid-algal mounds, the primary reservoir lithology, are exposed in the Barker Creek and Akah zones throughout The Goosenecks section of the San Juan River. These mounds vary in length from a few tens of feet to several hundred feet, often rapidly pinching out into non-mound lithofacies (figures 11-65, 11-66, and 11-67). The thickness is also variable from a few tens of feet to well over 50 feet (16 m). Mounds are occasionally stacked but separated by either mound-cap or substrate facies (figure 11-68). Mound flanks are well exposed and consist of angular, poorly sorted clasts of mound material (figure 11-69), whereas intermound channel grainstone deposits show excellent cross-bedding (figure 11-70).

Horizontal drilling has only been conducted in a few typical fields in the Paradox Basin with no commercial success; the exception is within the atypical Greater Aneth field where horizontal drilling has become a significant best practice (see Chapter 15). Phylloid-algal mounds in The Goosenecks demonstrate that there are various targets and risks when considering potential horizontal drilling in small, heterogeneous reservoirs in the Paradox Basin. Before selecting the optimal location, orientation, and type of horizontal well (for example single or multiple horizontal laterals, radially stacked laterals, splays or branches), the distribution, both laterally and vertically, of the mound or mounds, mound flanks, and other associated lithofacies must be carefully evaluated.

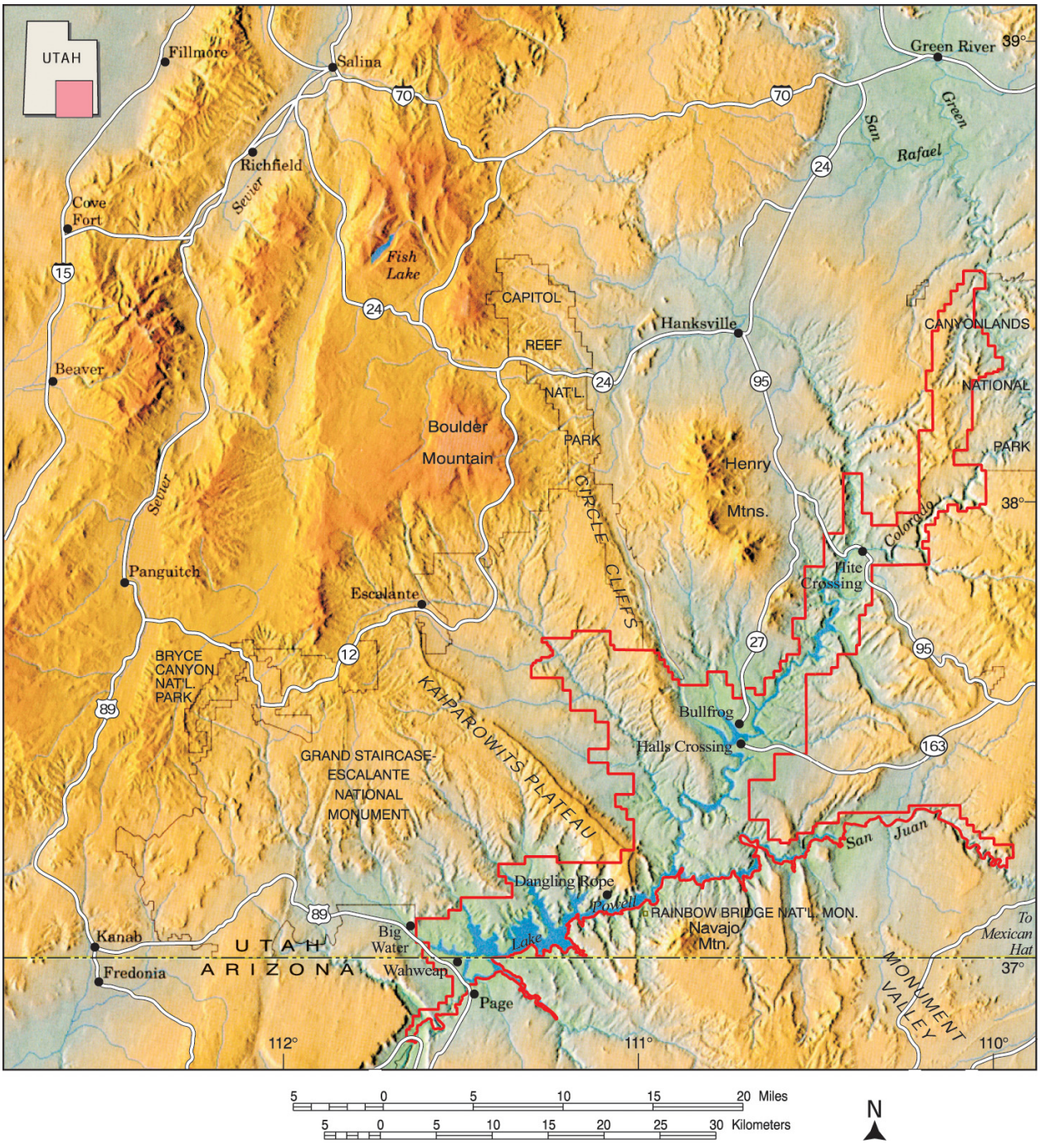


Figure 11-1. Index map to Glen Canyon National Recreation Area, Utah and Arizona (modified from Hintze, 1997; topographic relief base map modified with permission, courtesy of Chalk Butte, Inc., Boulder, Wyoming).

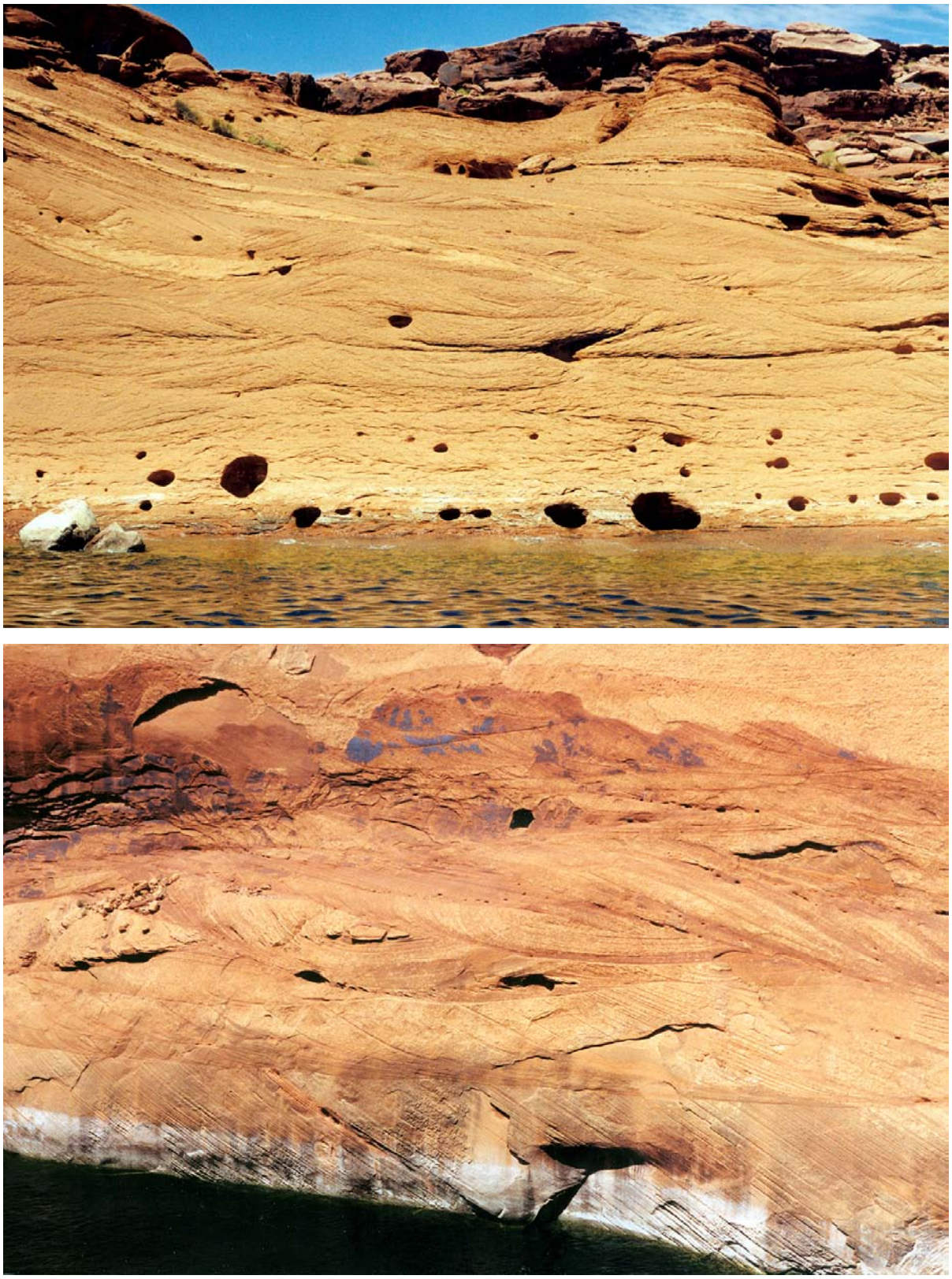
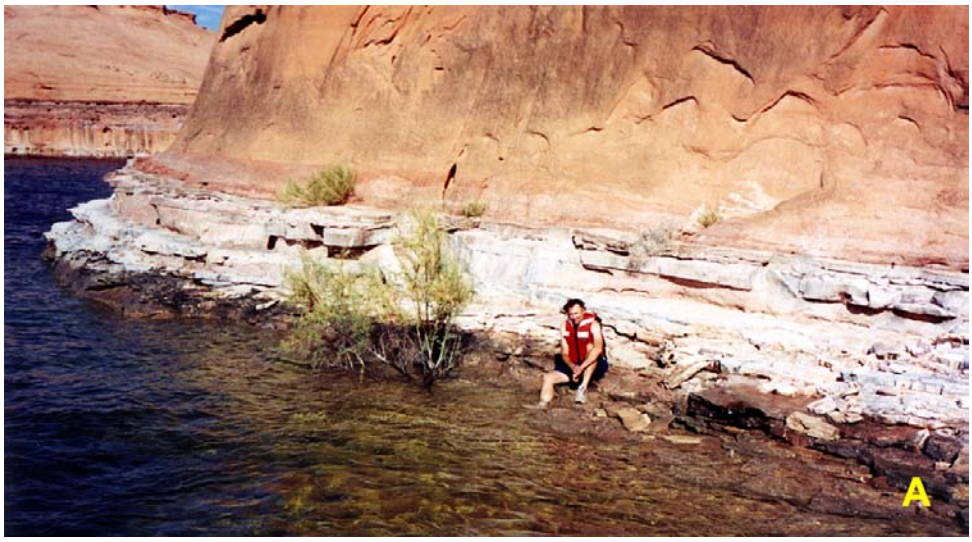


Figure 11-2. Navajo Sandstone beds display pronounced trough cross-bedding which indicates the paleowinds were from the north and northwest, Lake Powell, Glen Canyon National Recreation Area, Utah.



Figure 11-3. Spectacular contorted bedding in Navajo Sandstone; south side of Antelope Island in Lake Powell, Glen Canyon National Recreation Area, Arizona.



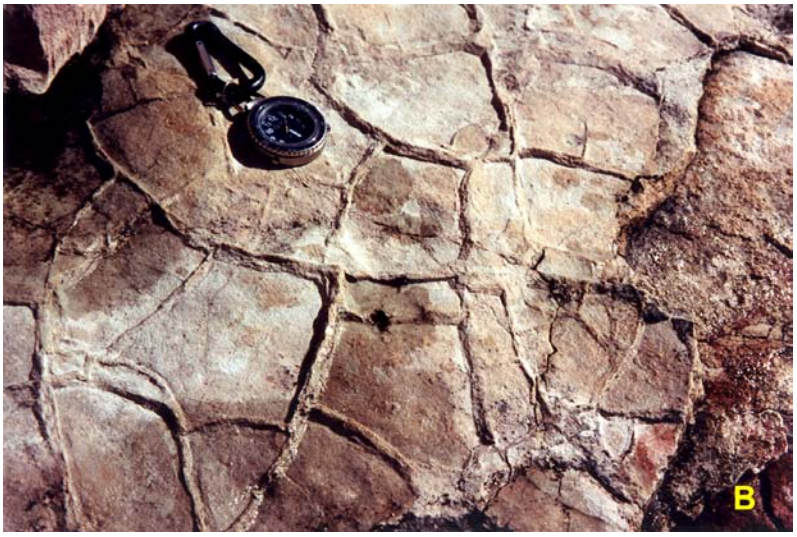
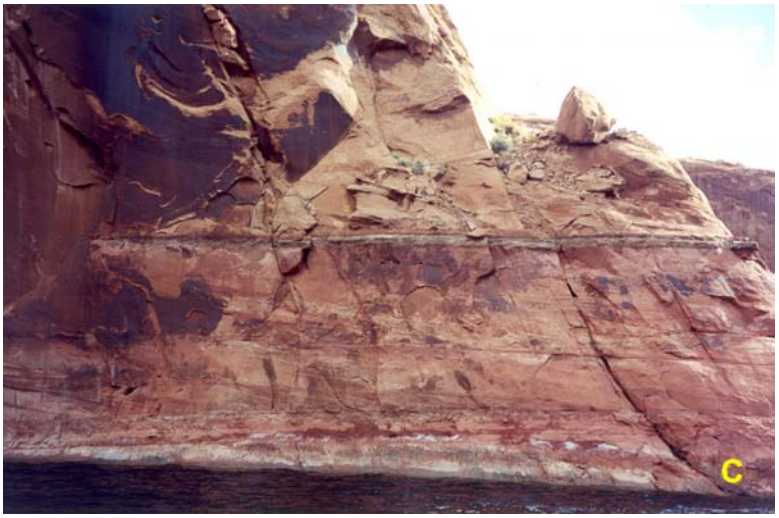
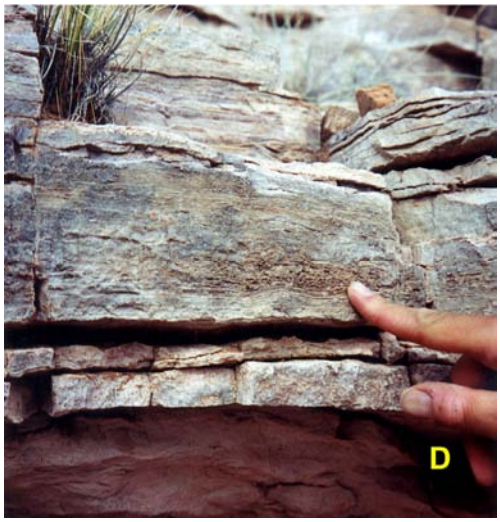


Figure 11-4. Oasis deposits in the Navajo Sandstone, Lake Powell, Glen Canyon National Recreation Area, Utah. A - Typical limestone oasis deposit near the top of the Navajo Sandstone; Forgotten Canyon. B - Mudcracks in oasis limestone mud above bed containing ripple marks; Forgotten Canyon. C - Rapid pinch out of thin limestone bed; Moki Canyon. D – Algal laminae within the limestone oasis beds in the Navajo Sandstone; Moki Canyon.





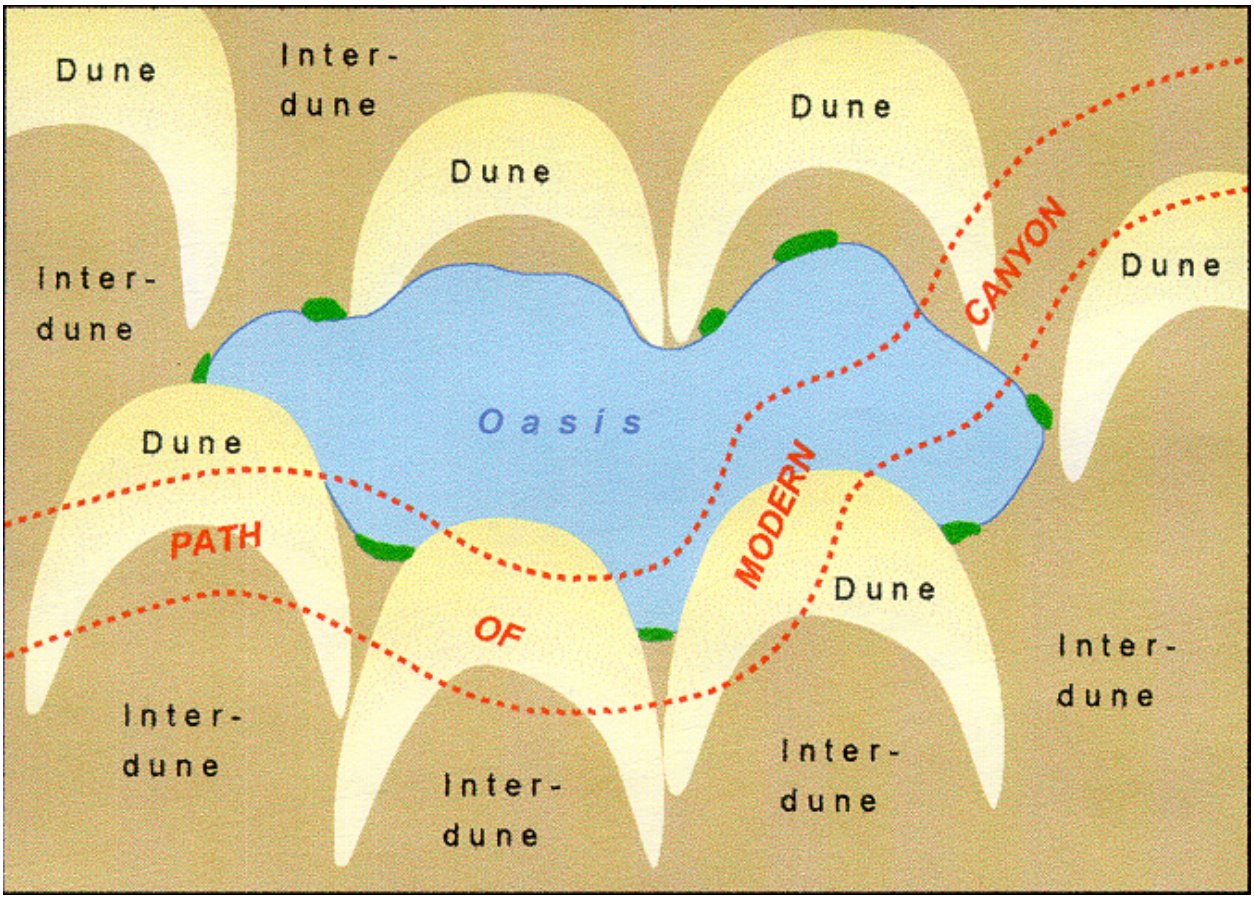


Figure 11
large dunes. The path of a modern canyon is superimposed to demonstrate the rapid pinch outs of limestones observed along the canyon walls; many of the limestones probably belong to the same oasis deposits.

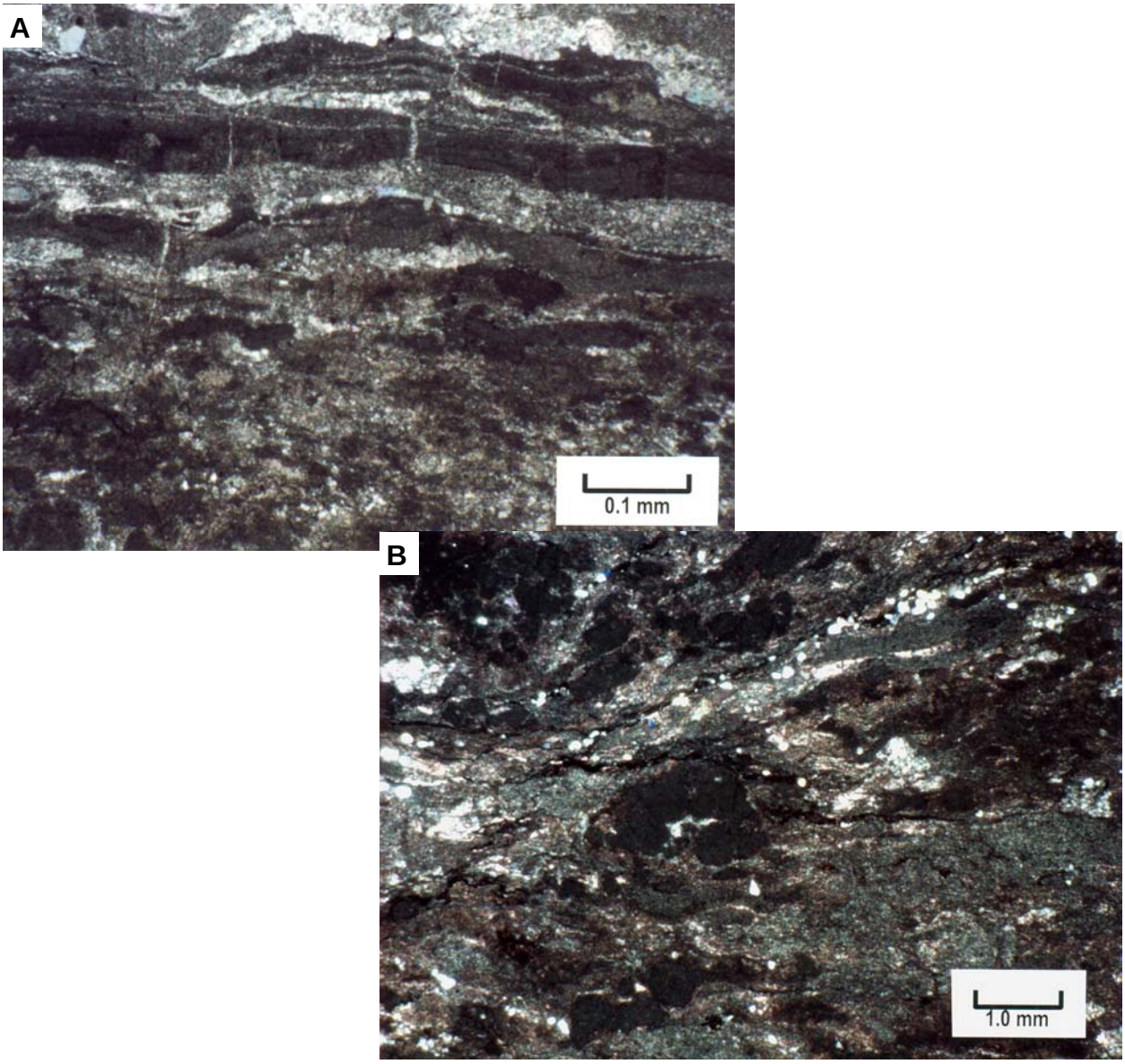


Figure 11-6. Photomicrographs (crossed nicols) of oasis deposits, Navajo Sandstone, Glen Canyon National Recreation Area, Utah. A - Couplets of alternating cryptalgalaminites and massive microcrystalline layers dominate the upper half of this micrograph. The laminated bands are mostly calcitic (limestones) while the lighter-colored microcrystalline bands are mostly dolomites. These mm-scale couplets are typical of organic blue-green algal or cyanobacterial mats. The lighter-colored, massive or microcrystalline bands are probably the result of dolomitized storm deposits while the microlaminated layers are the result of normal microbial mat trapping and binding activities. The lower half of this image shows a greater concentration of dark-colored rip-up intraclasts. B - Dark-colored clots and pin cushion-like patches of micrite are surrounded by lighter-colored, partially dolomitized detrital sediments and small, white quartz grains. Several of these lumpy clots can be termed "thrombolites." They were most likely created by coccoid blue-green algal or cyanobacterial processes. Such microbial structures could have easily formed in stressed environments that were intermittently desiccated. Salinity stresses, ranging from fresh to hypersaline waters, can promote these types of microbial mini-structures. Photomicrographs and description by D.E. Eby, Eby Petrography & Consulting, Inc., written communication, 2003.

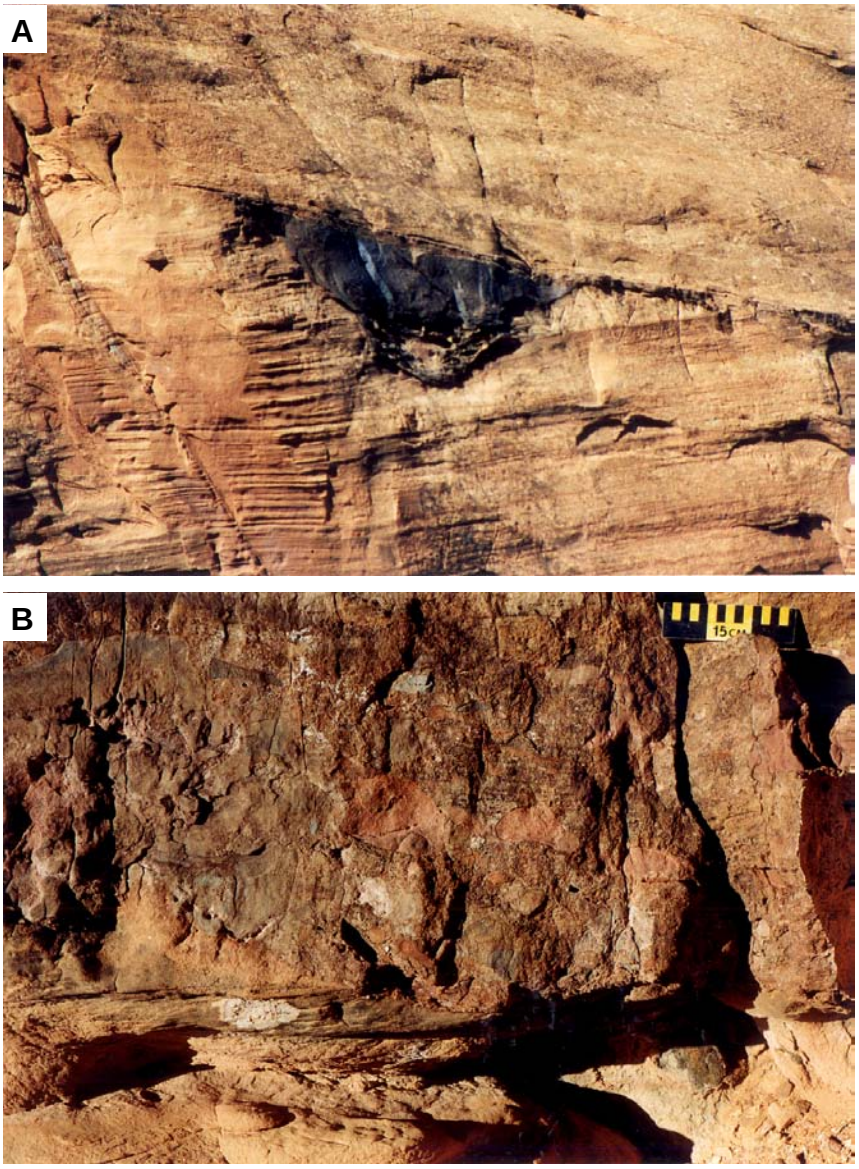


Figure 11-7. Wadi deposits in the Navajo Sandstone at Rainbow Bridge National Monument, Utah. A – Wadi channel, filled with strongly cemented sand, on the cliff face of the south side of the canyon; channel deposit is about 5 feet (2 m) thick (taken with a telephoto lens). B – Wadi "pudding stone" consisting of sandstone and dolomitic limestone rip-up clasts in a medium- to coarse-grained sandstone matrix. Note horizontal stratification and small-scale cross-beds at base of photo. C - Schematic interpretation, map view, of a Navajo wadi system between large dunes with the path of a modern canyon superimposed.

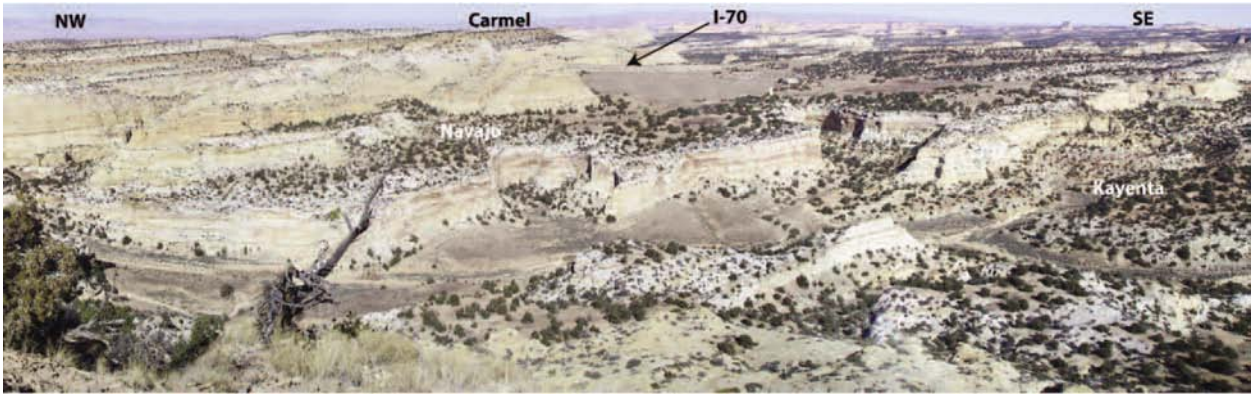


Figure 11-8. Panorama of the Devils Canyon area, west flank of the San Rafael Swell, central Utah, showing the Navajo Sandstone. A prevalent surface within the Navajo Sandstone represents a laterally extensive interdune deposit with low permeabilities making this facies likely a barrier to fluid flow if it were in a reservoir. Juniper trees for scale. After Dalrymple and Morris (2007).

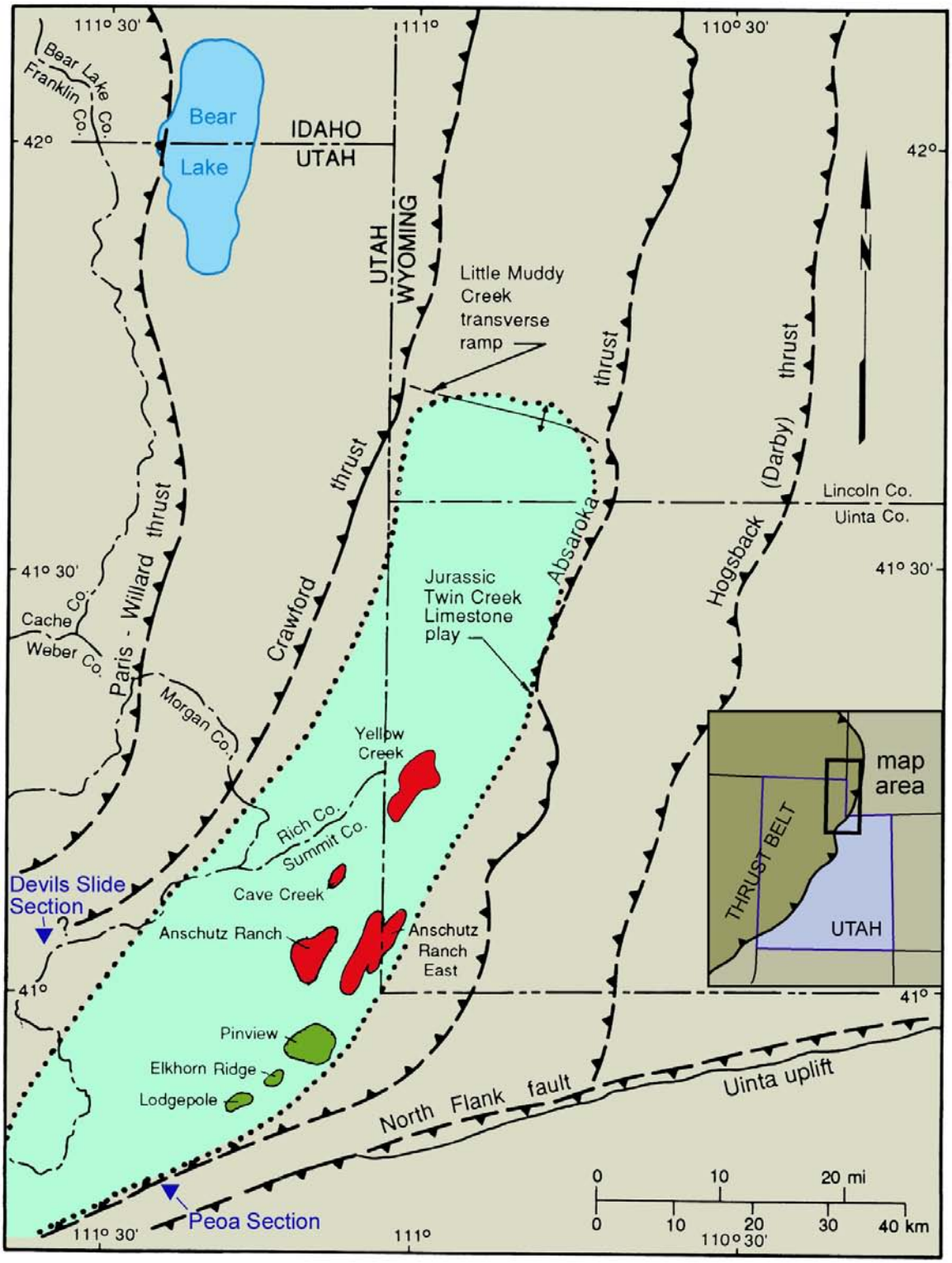


Figure 11-9. Location of outcrop analogs for reservoirs that produce oil (green) and gas and condensate (red) from the Jurassic Twin Creek Limestone, Utah and Wyoming; major thrust faults are dashed where approximate (teeth indicate hanging wall). The Twin Creek Limestone play area is dotted (modified from Sprinkel and Chidsey, 1993).

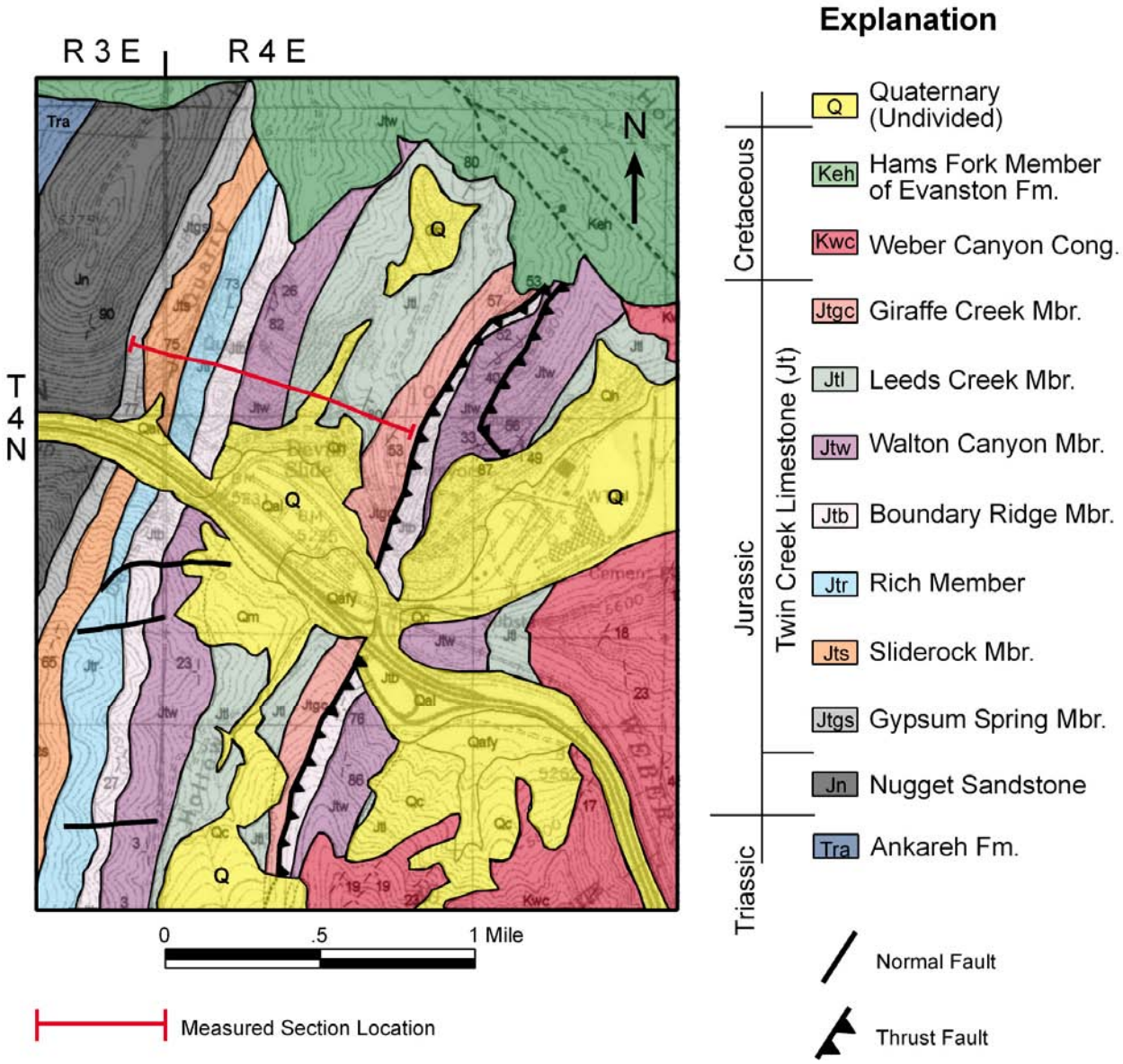


Figure 11-10. Geologic map of the Devils Slide area, Morgan and Summit Counties, Utah, showing the location of the stratigraphic measured section through the Twin Creek Limestone (modified from Coogan, 1999). See figure 11-9 for location of Devils Slide area.

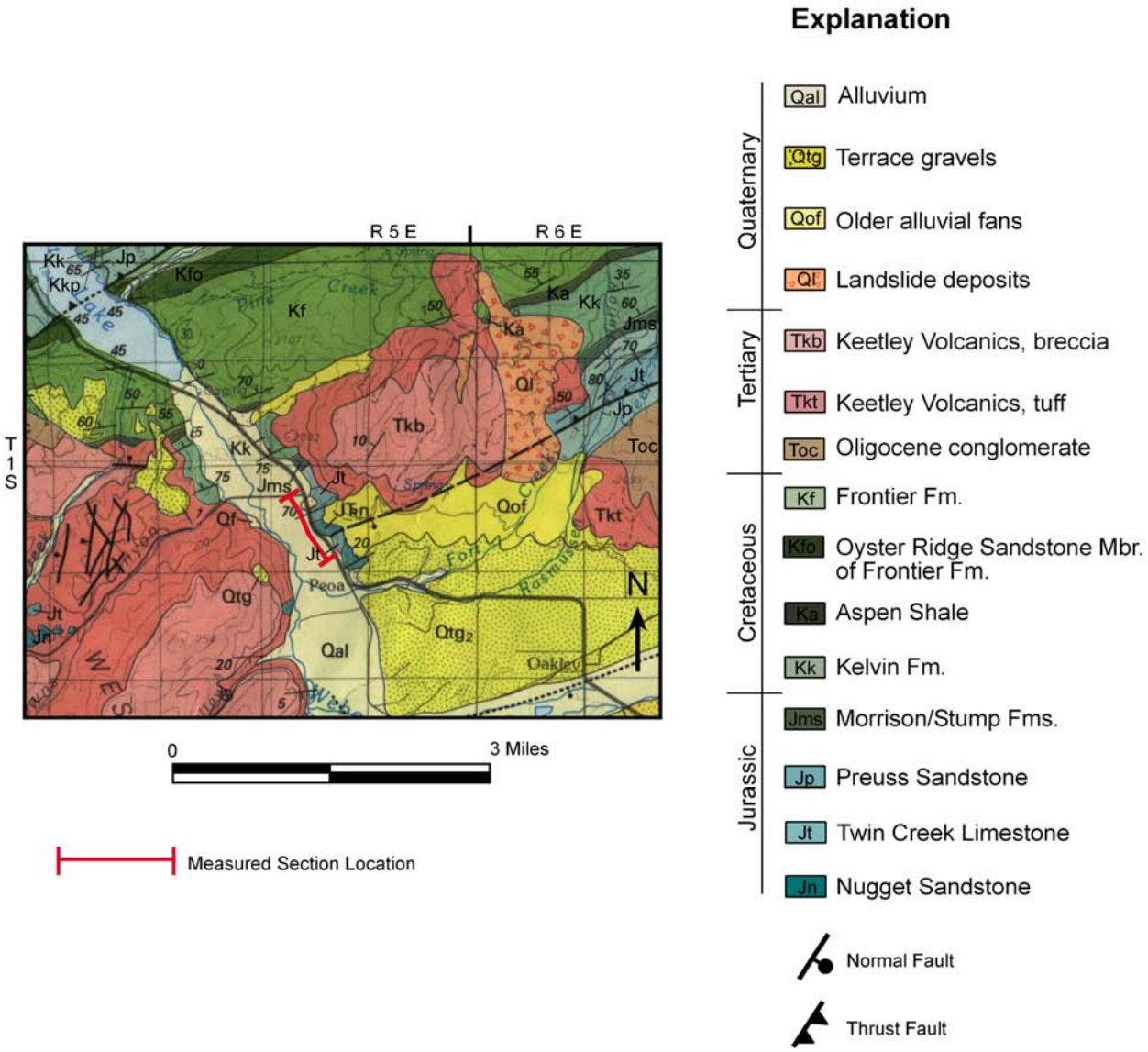


Figure 11-11. Geologic map of the Peoa area, Summit County, Utah, showing the location of the stratigraphic measured section through the Twin Creek Limestone (modified from Bryant, 1990). See figure 11-9 for location of Peoa area.

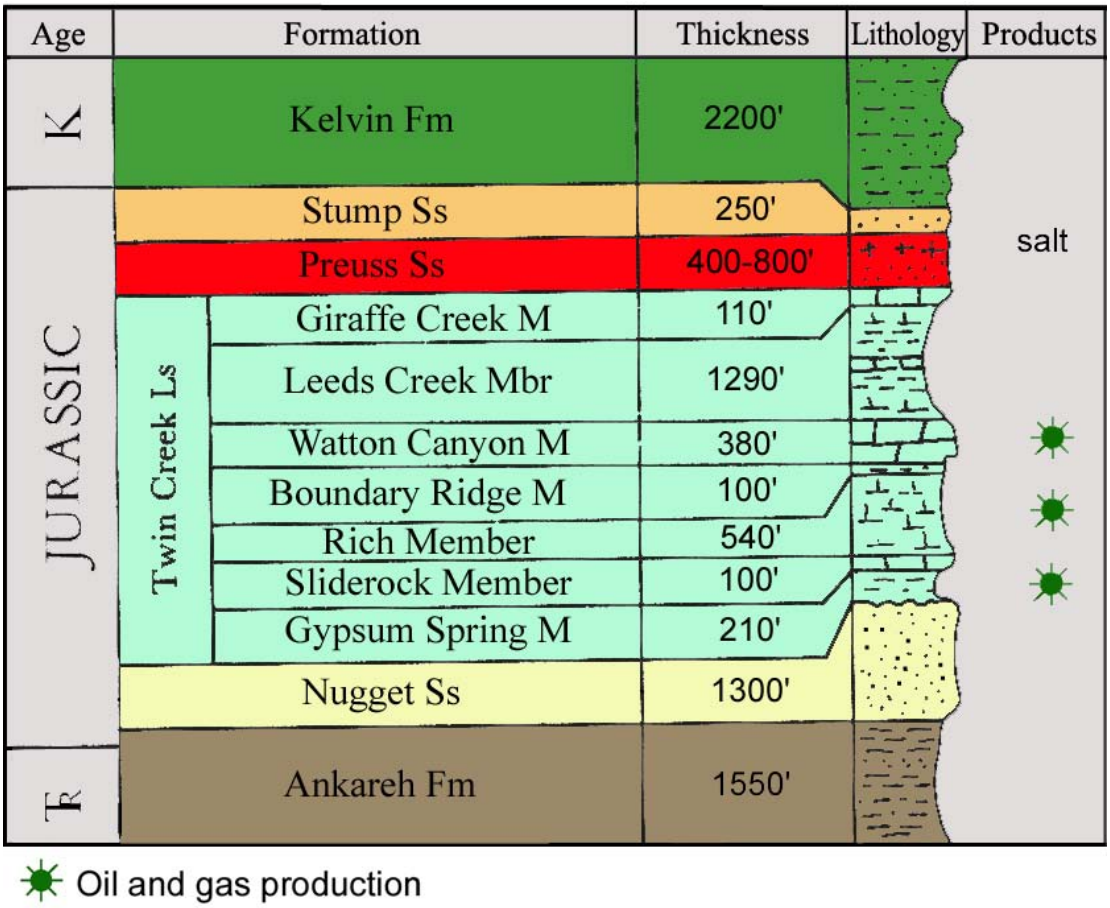


Figure 11-12. Stratigraphic column of a portion of the Mesozoic section, including members of the Jurassic Twin Creek Limestone, exposed in Weber Canyon near Devils Slide, Morgan and Summit Counties, Utah (modified from Hintze, 1993).

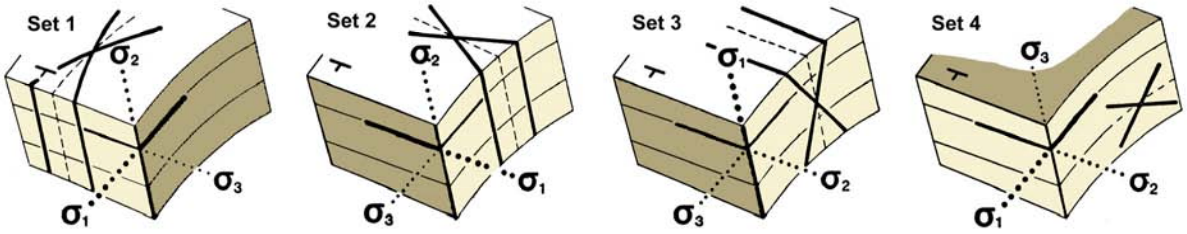


Figure 11-13. Fracture planes generated by four orientations of the three principal stresses during folding of sedimentary rocks (after Stearns, 1984).



Figure 11-14. Devils Slide, a famous landmark along Interstate 84 in Weber Canyon, composed of resistant and non-resistant units of the Rich Member of the Twin Creek Limestone.

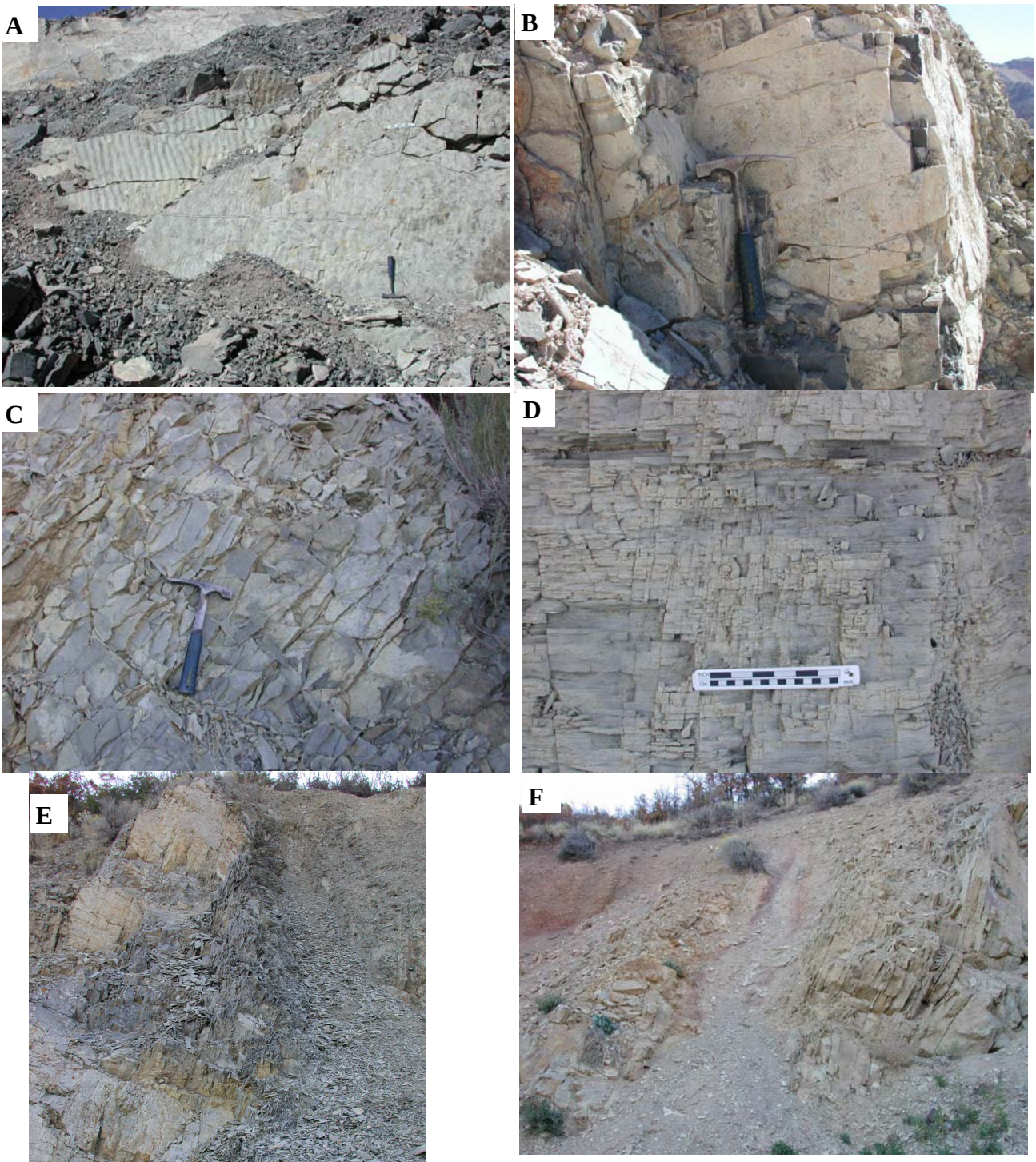


Figure 11-15. Characteristics of the Rich Member of the Twin Creek Limestone. A - Well-developed current ripples on bedding surface with silt-filled fractures, Devils Slide section. B and C – Rhombic fracture patterns on bedding planes, Devils Slide and Peoa sections, respectively. D – Closely spaced rectilinear fracturing, Peoa section, E – Pencil weathering, Peoa section. F – Contact between fractured Rich Member limestone and basal siltstone with sealed fractures of the overlying Boundary Ridge Member, Peoa section.

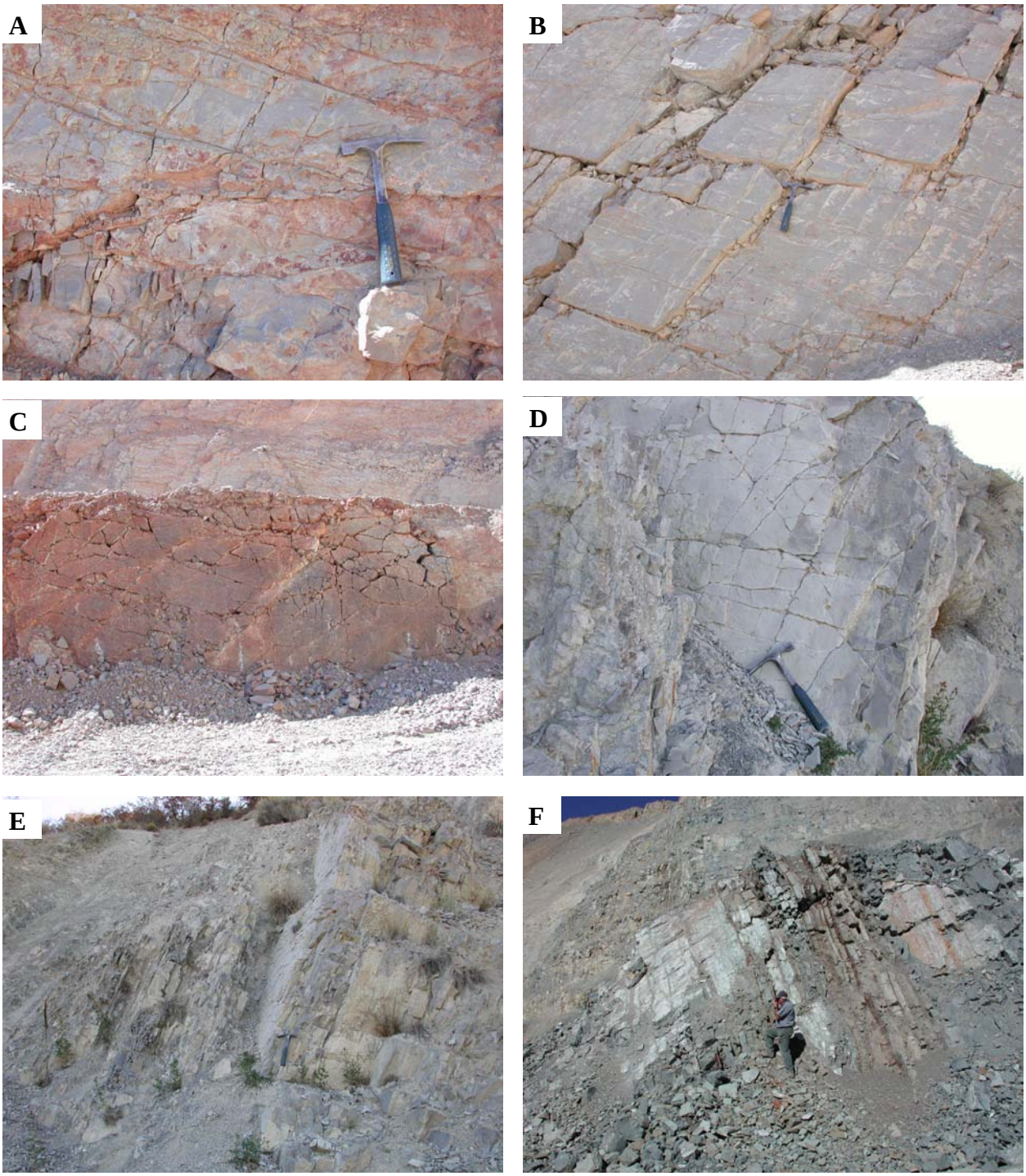


Figure 11-16. Characteristics of the Watton Canyon Member of the Twin Creek Limestone. A - Closely spaced rectilinear fracturing in dense, micritic limestone, Devils Slide section. B – Large-scale, well-displayed rectilinear fracturing in steeply dipping limestone, Devils Slide section. C - Large-scale, open fractures on bedding plane surface, Devils Slide section. D - Well-displayed rectilinear fracturing on top of the Watton Canyon, Peoa section. E - Contact between fractured Watton Canyon Member limestone and basal argillaceous unit of the overlying Leeds Creek Member, Peoa section. F – Heterogeneity within the Watton Canyon Member caused by thin-bedded siltstone, Devils Slide section.

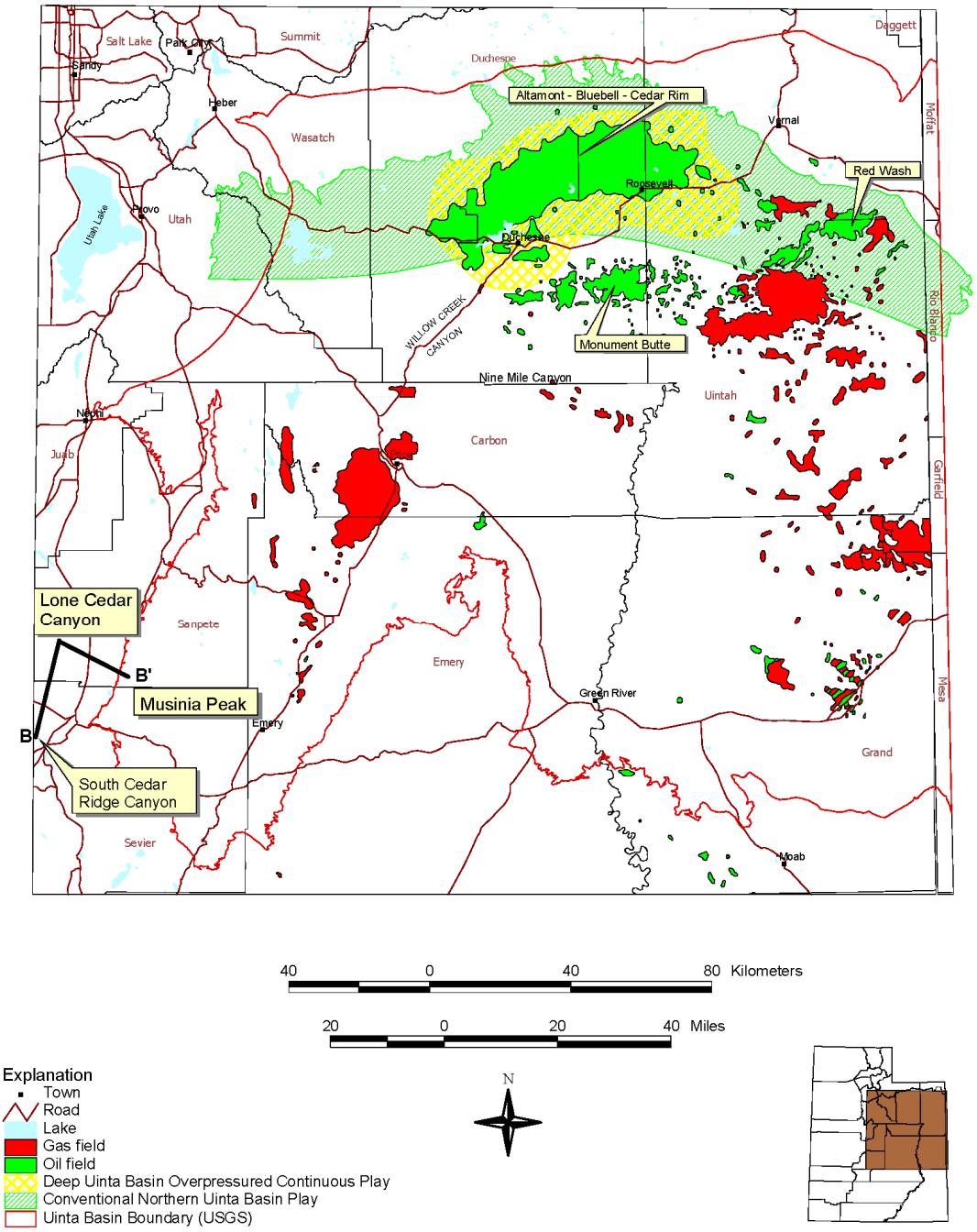


Figure 11-17. Location map showing the outline of the Uinta Basin and major oil and gas fields. The Conventional Uinta Basin Northern play area and the Deep Uinta Basin Overpressured Continuous play area are shown. Cross section B – B' (figure 11-18) is a series of outcrops in the Flagstaff Limestone demonstrating the proximal to distal facies change that is typical of the two plays.

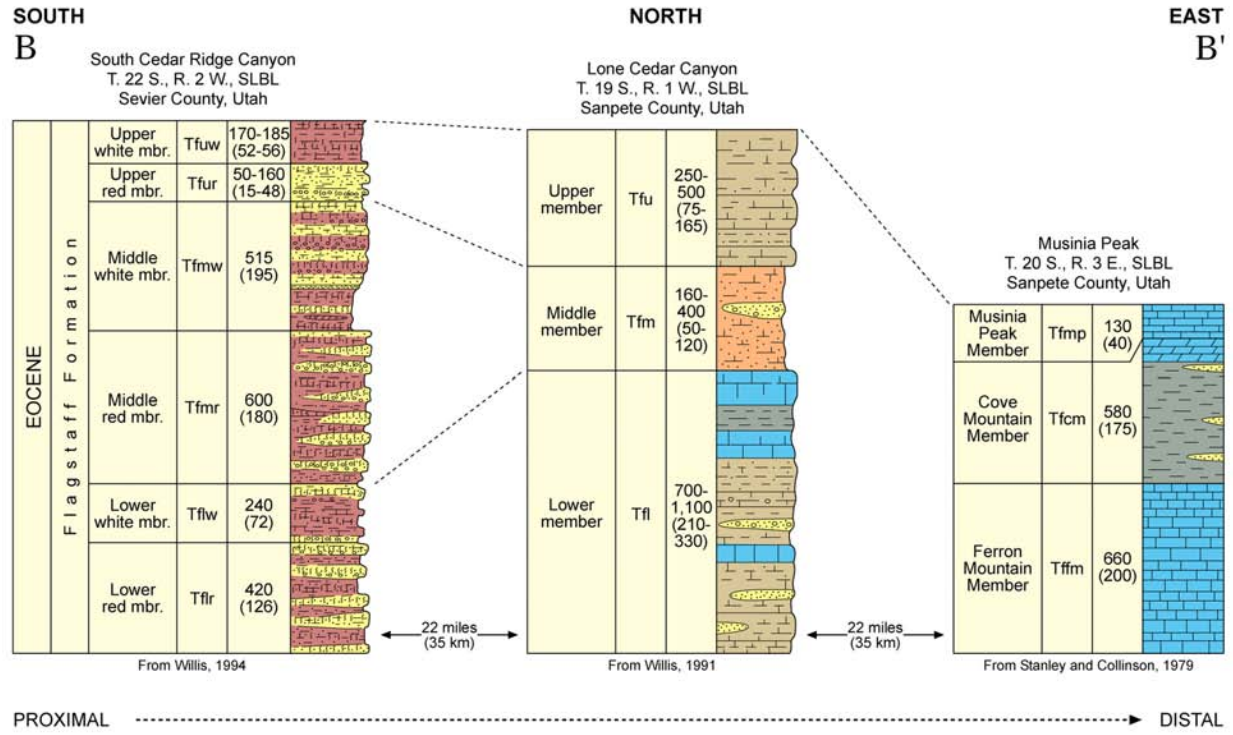


Figure 11-18. Cross section of measured stratigraphic sections showing transition from proximal to distal facies in the Flagstaff Limestone, similar to the north-south facies change in the Altamont-Bluebell-Cedar Rim field area. Line of section shown on figure 11-17.



Figure 11-19. Proximal facies of the Flagstaff Limestone exposed along the east face of the Gunnison Plateau. At this location the Flagstaff is composed of sandstone and siltstone deposited as alluvial fans from the highlands to the southwest.



Figure 11-20. Sandstone and conglomerate beds in the proximal facies of the Flagstaff Limestone in South Cedar Ridge Canyon. Some of these beds appear to have been deposited in shallow lake water as fan deltas.



Figure 11-21. Marginal-lacustrine medial facies of the Flagstaff Member of the Green River Formation in Price River Canyon. The outcrop is composed of interbedded red and gray shale, sandstone, and some carbonate.



Figure 11-22. Distal facies of the Flagstaff Limestone exposed in Manti Canyon on the Wasatch Plateau. The outcrop is composed of open-lacustrine limestone and shale overlying the North Horn Formation (red beds).

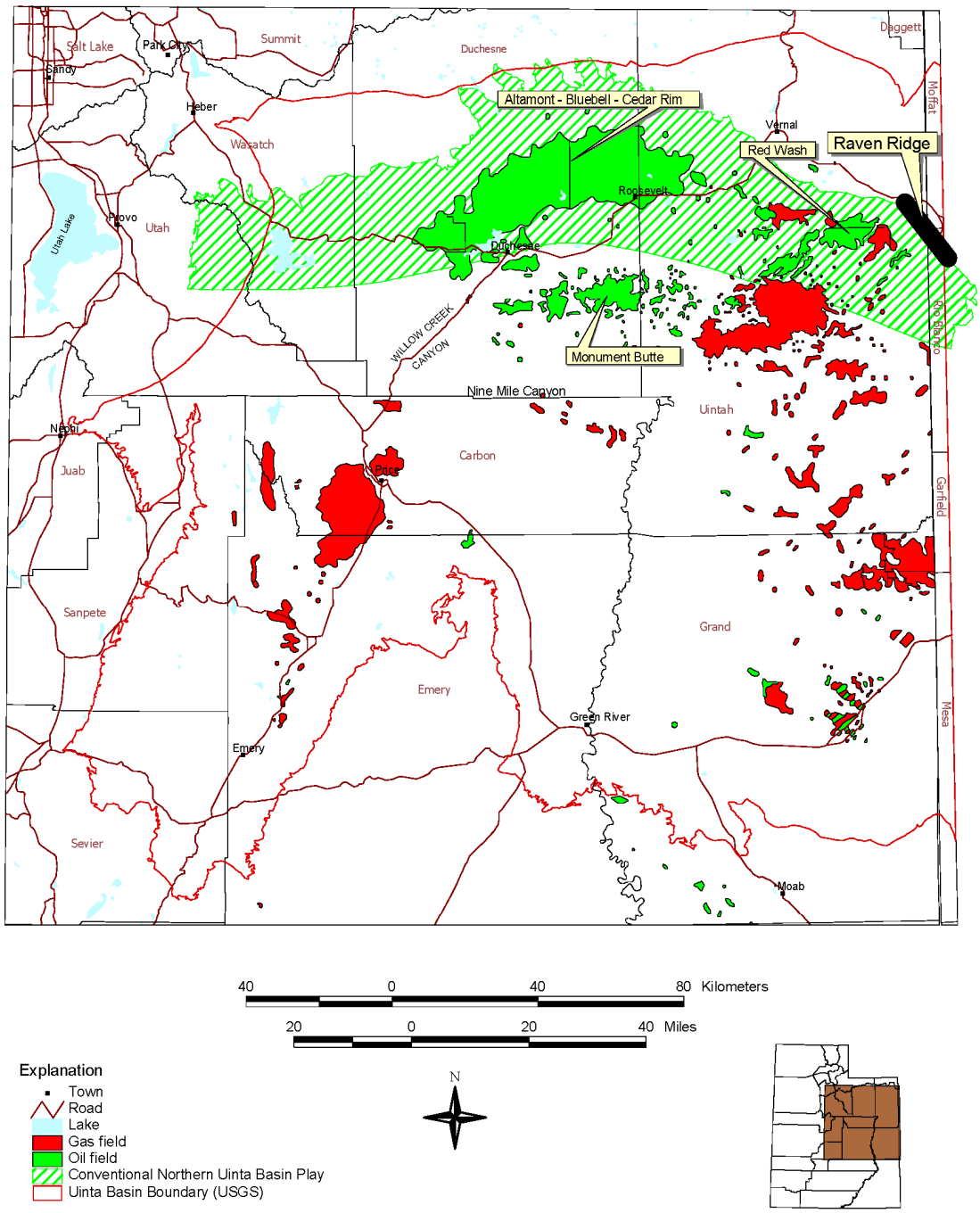


Figure 11-23. Location map showing the outline of the Uinta Basin and major oil and gas fields. The Conventional Northern Uinta Basin play area is colored light green and the location of Raven Ridge where the Green River Formation is exposed is indicated.



Figure 11-24. Douglas Creek Member of the Green River Formation and underlying Wasatch Formation exposed along Raven Ridge. The outcrop is a good analog to sandstone reservoirs in Red Wash field of the Conventional Northern Uinta Basin play.



Figure 11-25. Organic-rich shale representing good oil source rock in the Douglas Creek Member of the Green River Formation at Raven Ridge of the Conventional Northern Uinta Basin play.

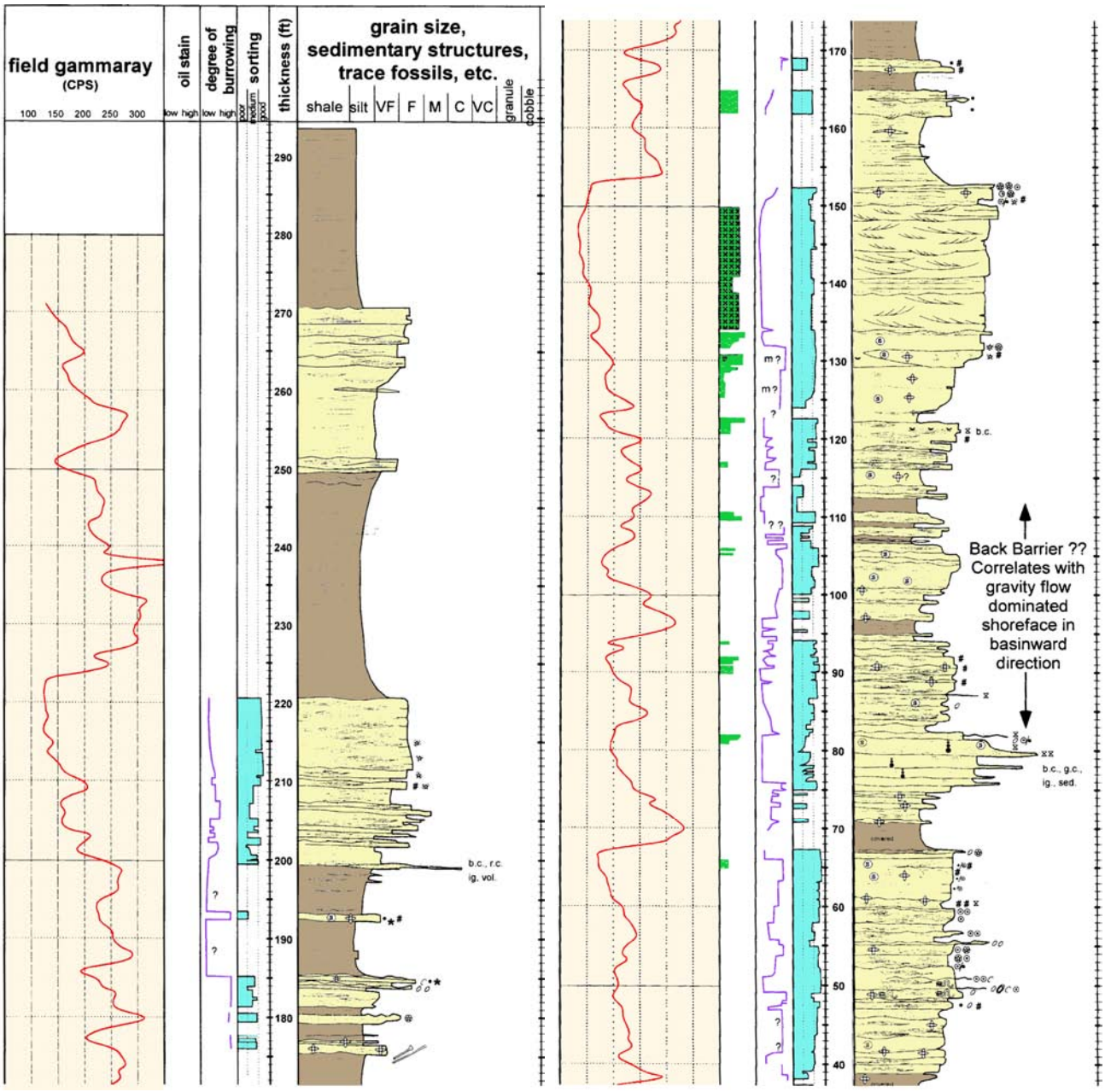


Figure 11-26. Stratigraphic measured section of the Douglas Creek Member, Green River Formation at Oil Gully, Raven Ridge, Uintah County, Utah. From Borer (2003).

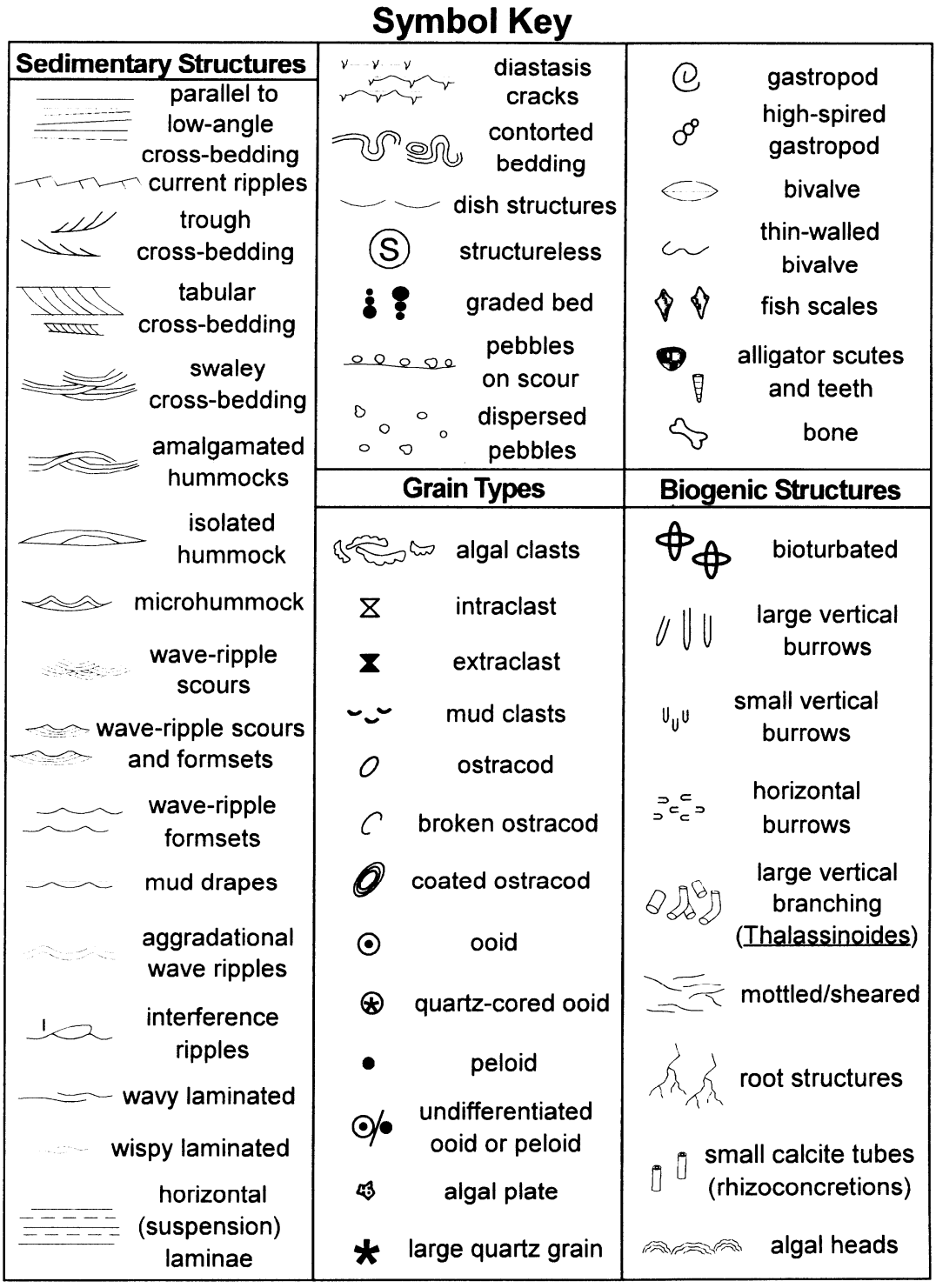


Figure 11-26. Continued

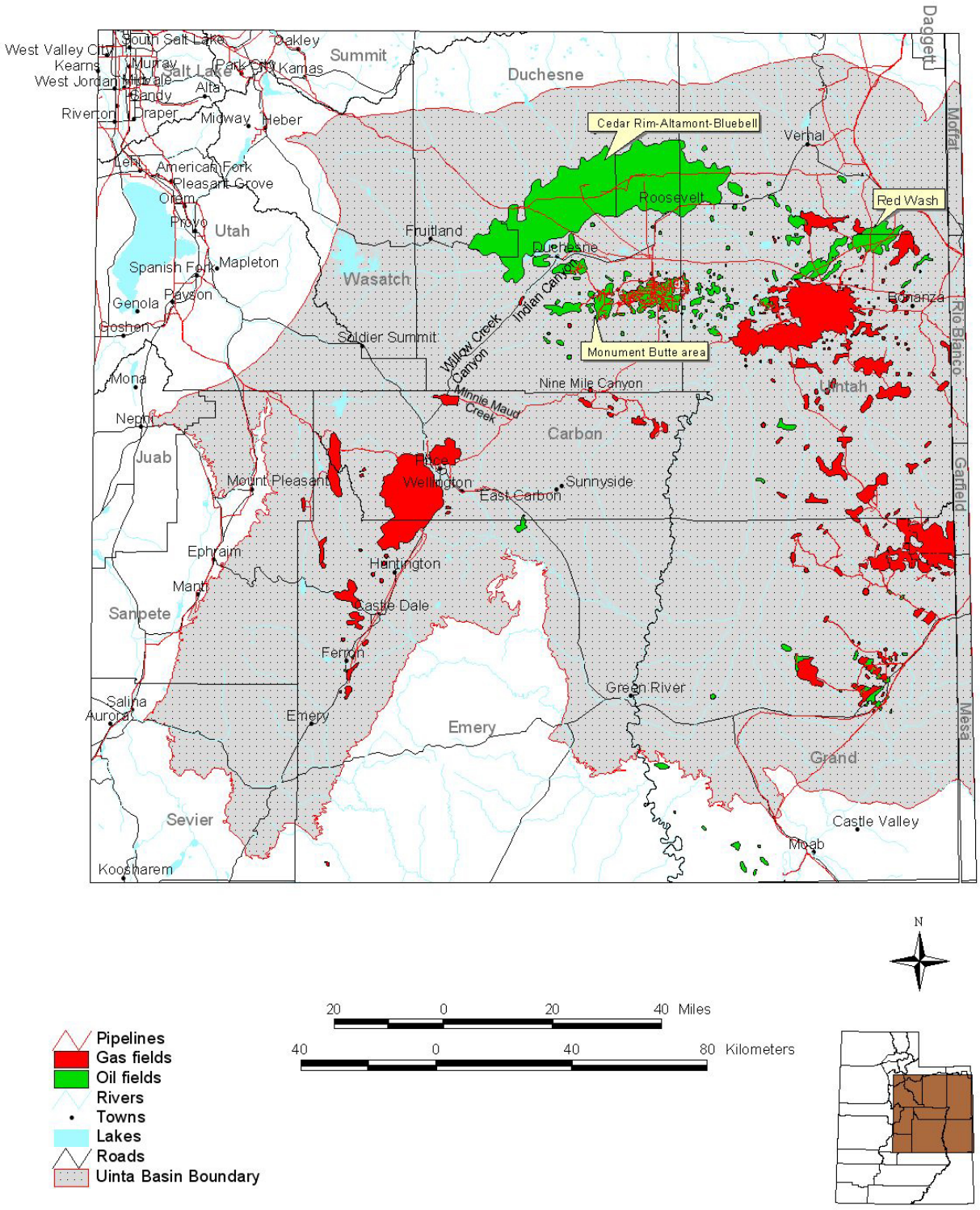


Figure 11-27. Map showing the location of the Uinta Basin (as defined by Dubiel [2003]), outcrop analogs (Willow Creek, Indian, and Nine Mile Canyons), and the oil and gas fields in and around the basin.

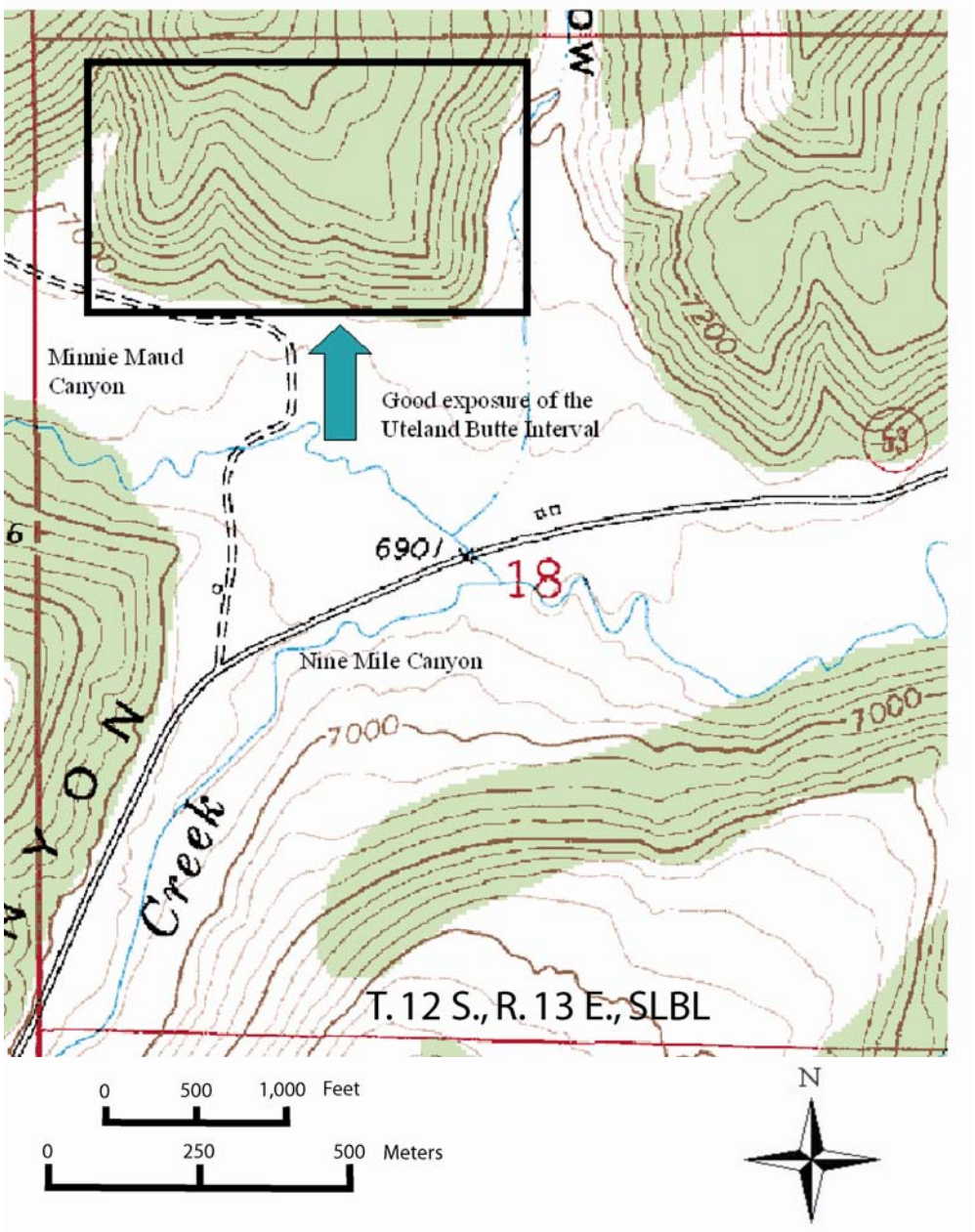


Figure 11-28. Map showing the location of exposures of the Uteland Butte interval in the lower Green River Formation, described by Little (1988) at the junction of Minnie Maud and Nine Mile Canyons. Base map modified from the USGS Minnie Maud Creek East 7.5 minute quadrangle.

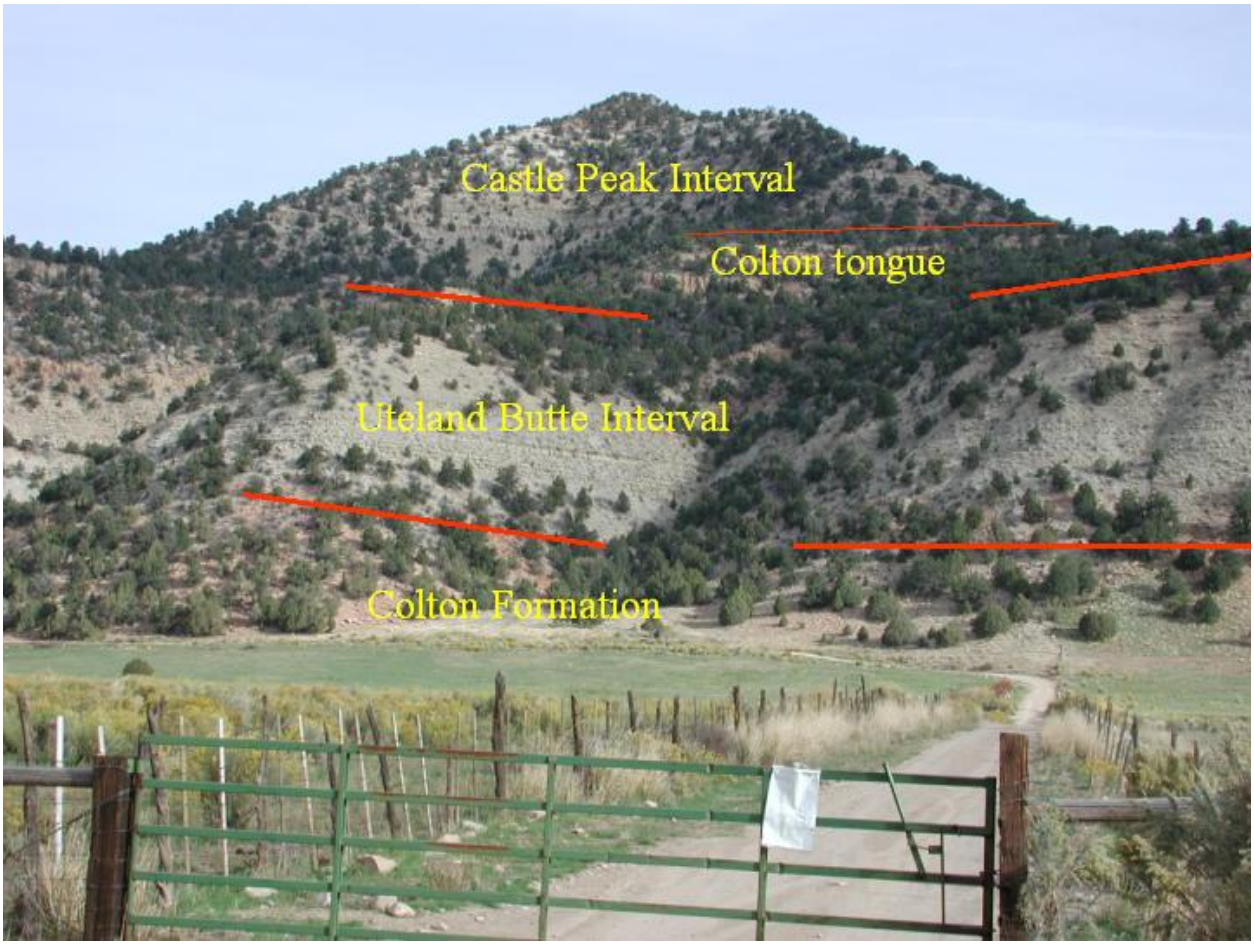


Figure 11-29. Exposure of the Uteland Butte interval of the lower Green River Formation, at the junction of Minnie Maud and Nine Mile Canyons; see figure 11-28 for location.

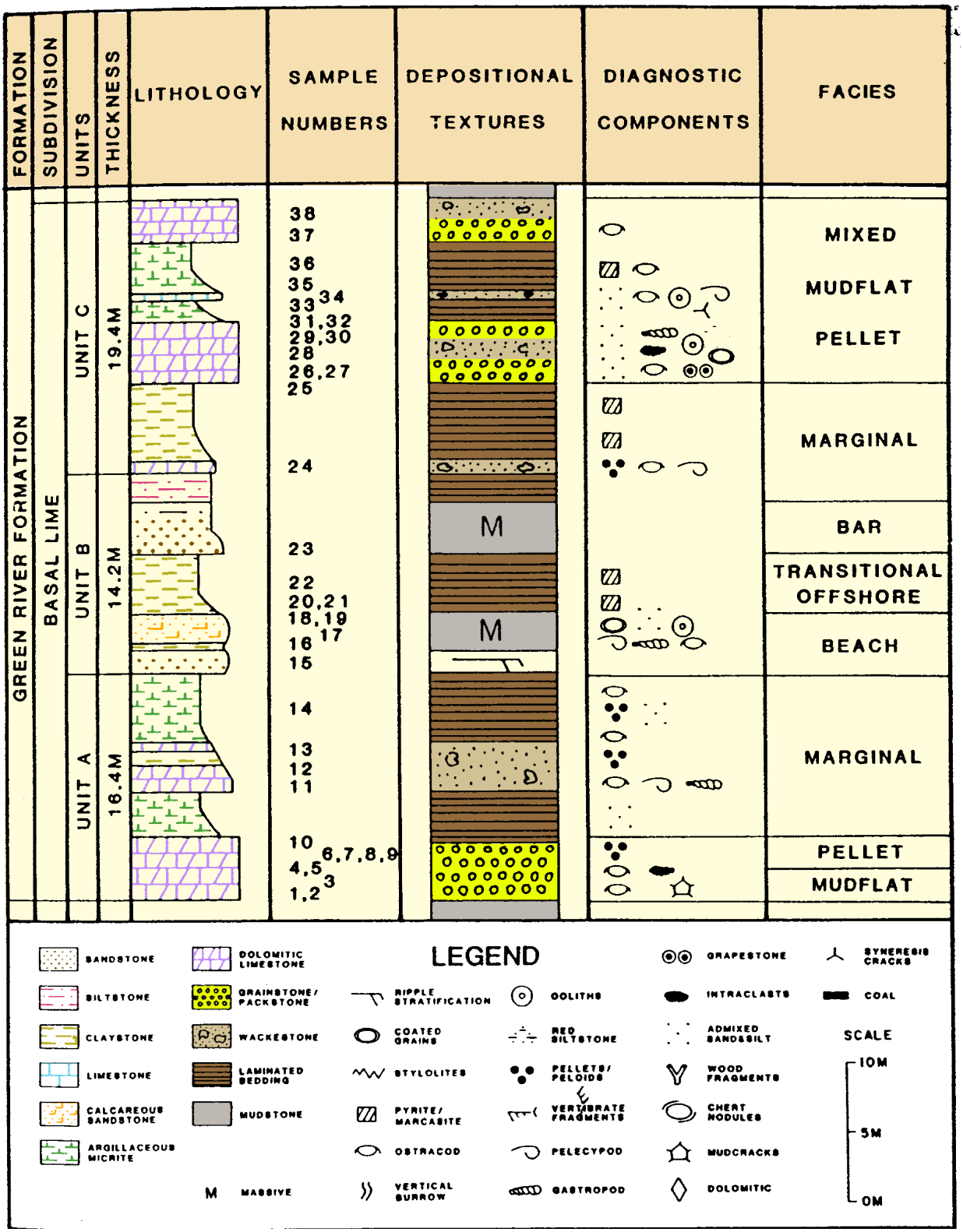


Figure 11-30. Stratigraphic measured section by Little (1988) of the Uteland Butte interval of the Green River Formation (Little's basal limestone facies) at the junction of Minnie Maud and Nine Mile Canyons.

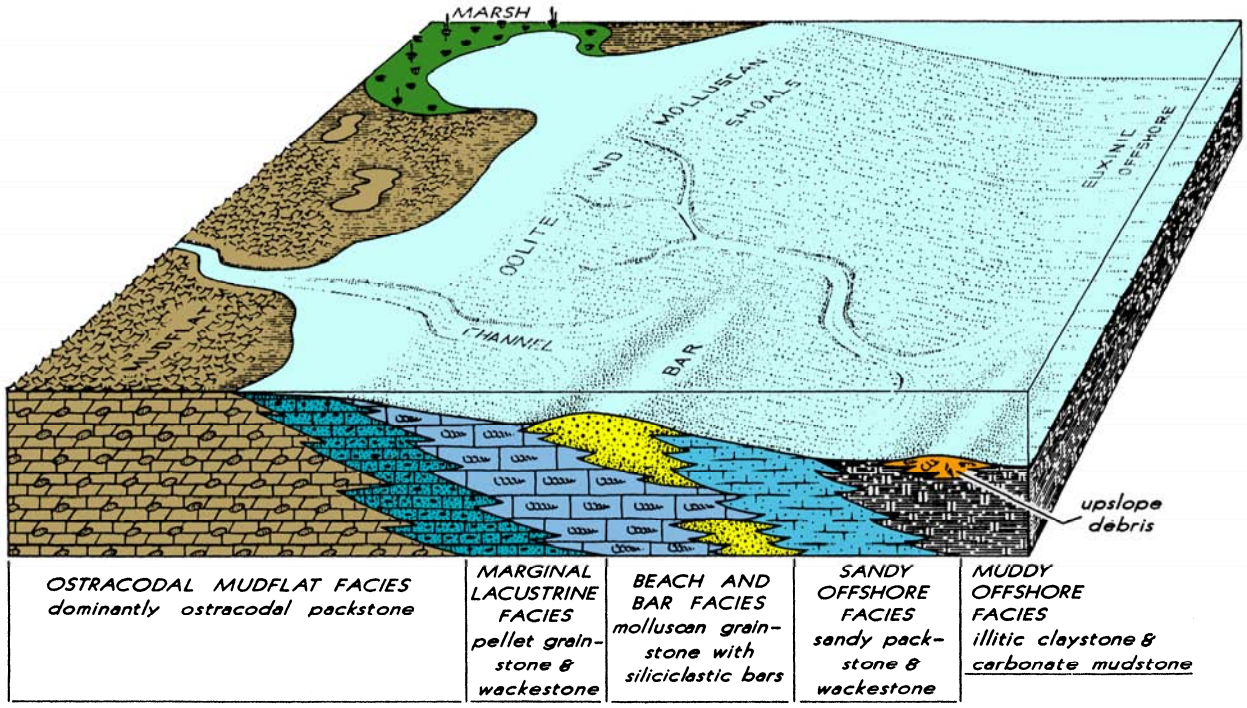


Figure 11-31. Conceptual three-dimensional diagram depicting major facies of the Uteland Butte interval of the Green River Formation. From Little (1988).

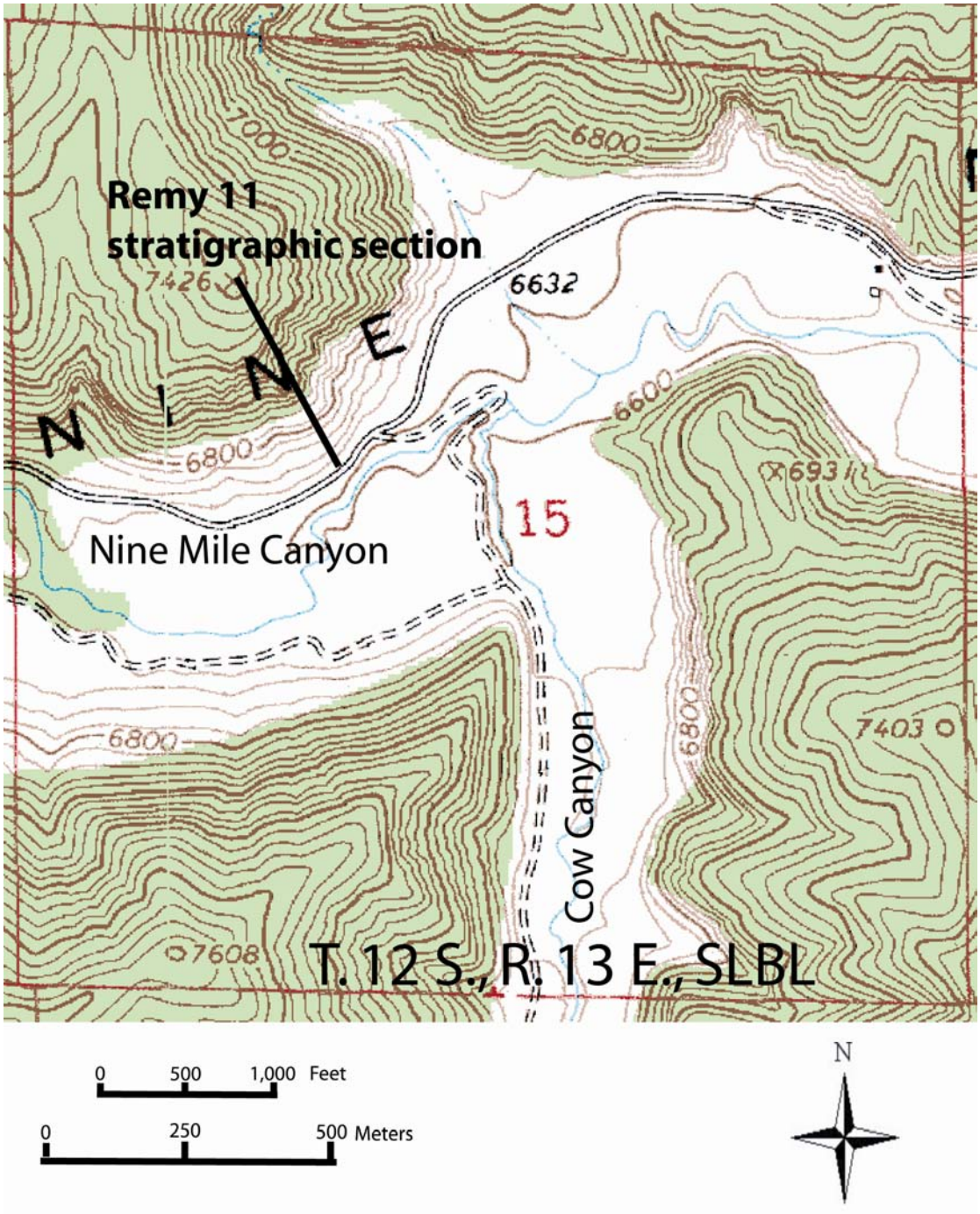


Figure 11-32. Map showing the location of the stratigraphic measured section of the Castle Peak interval and lower part of the Travis interval of the Green River Formation, by Remy (1992). Base map modified from the USGS Wood Canyon 7.5-minute quadrangle.

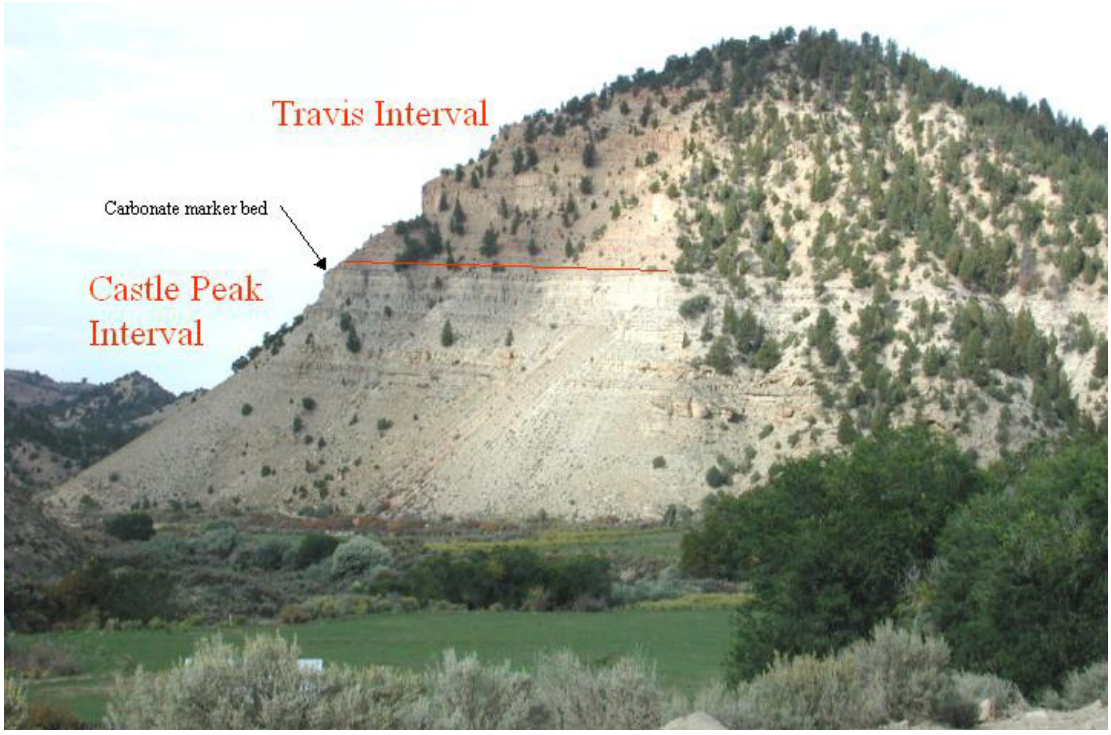


Figure 11-33. Photograph showing the location (figure 11-32) of Remy's (1992) stratigraphic measured section of the Castle Peak interval and lower part of the Travis interval of the Green River Formation.



Figure 11-34. Photograph of a carbonate bed and overlying channel sandstone deposit in the Castle Peak interval of the Green River Formation, Nine Mile Canyon.

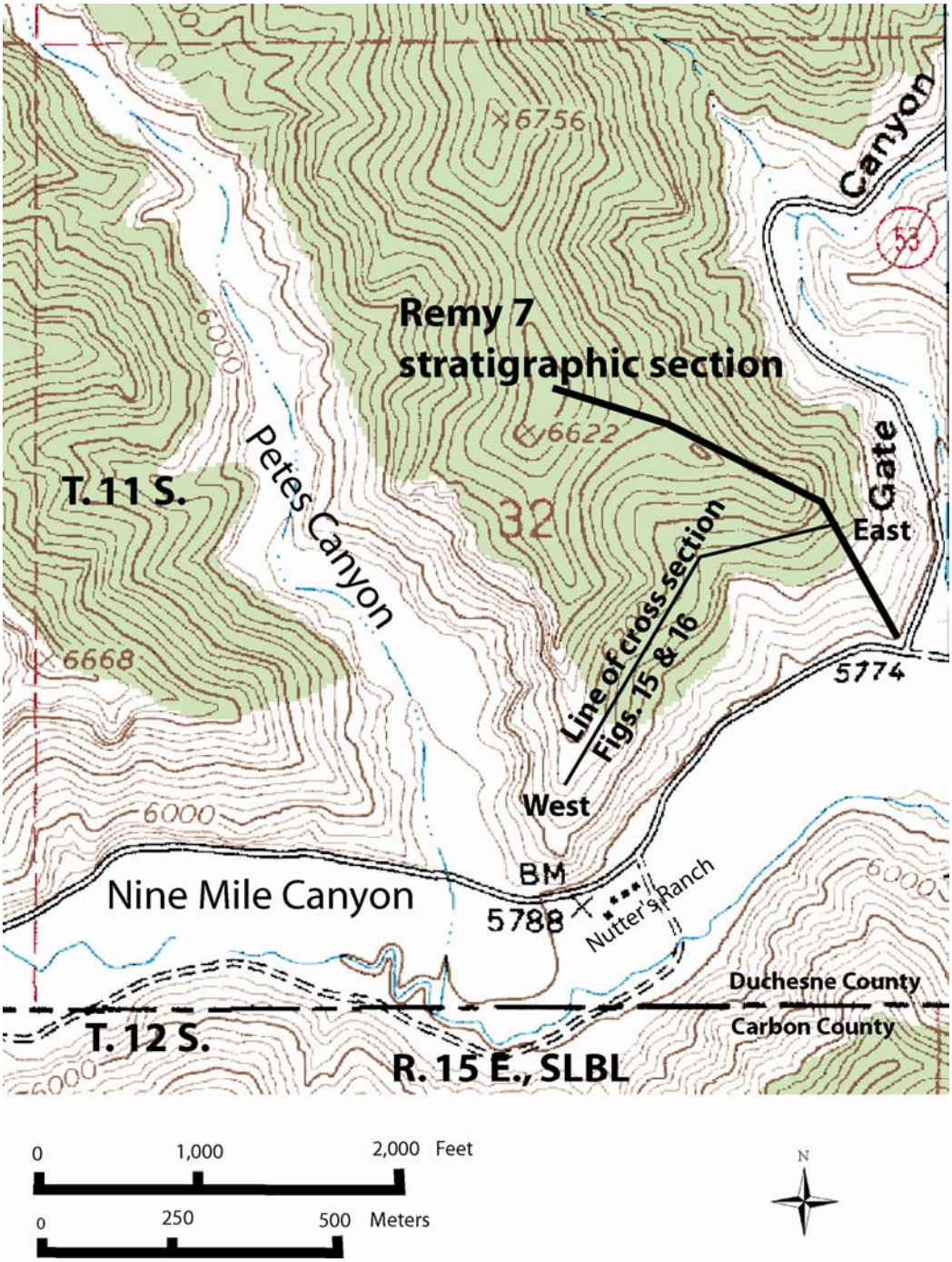


Figure 11-35. Map showing the location of the stratigraphic measured section of the Monument Butte and Beluga intervals of the middle Green River Formation, by Remy (1992), and the Nutter's Ranch study site between Petes and Gate Canyons in Nine Mile Canyon. Base map modified from the USGS Current Canyon 7.5-minute quadrangle.

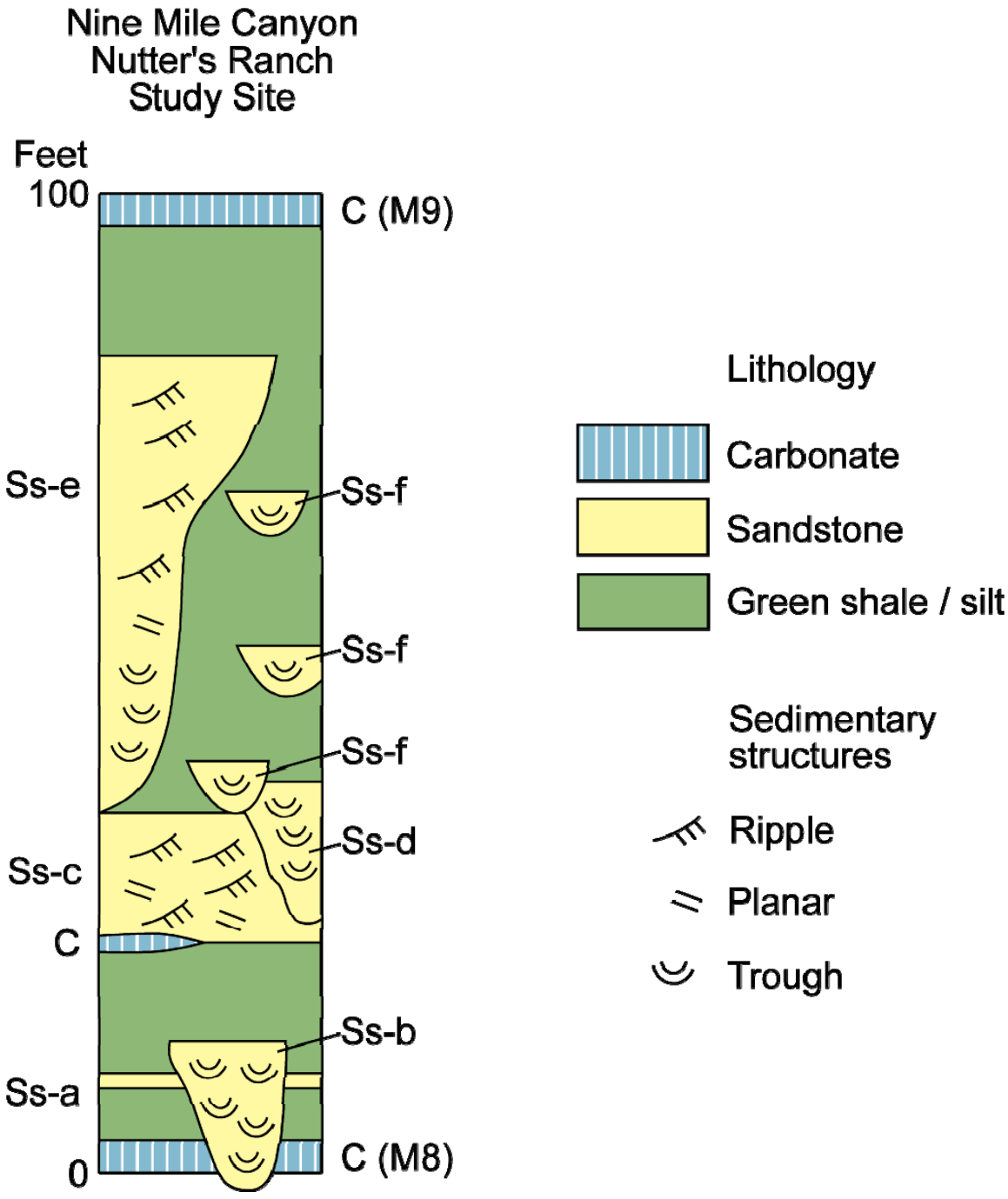


Figure 11-36. Composite vertical stratigraphic section of the middle Green River Formation, 100-foot depositional cycle in the Nutter's Ranch study site in Nine Mile Canyon. C = carbonate, Ss = sandstone.

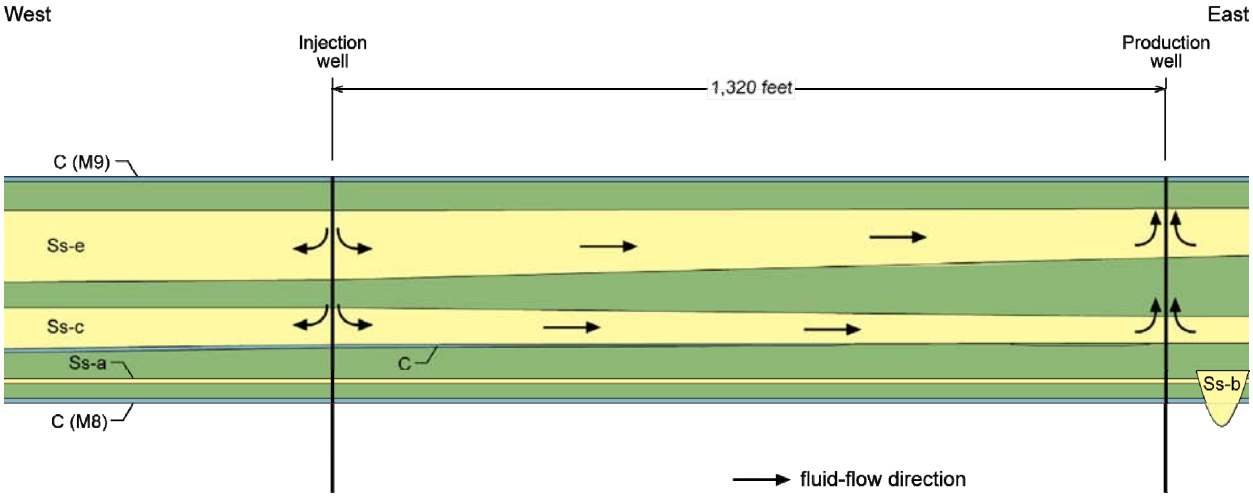


Figure 11-37. Hypothetical two-dimensional correlation and potential fluid-flow pattern between two imaginary wells "drilled" at the Nutter's Ranch study site. See figure 11-35 for location of cross section.

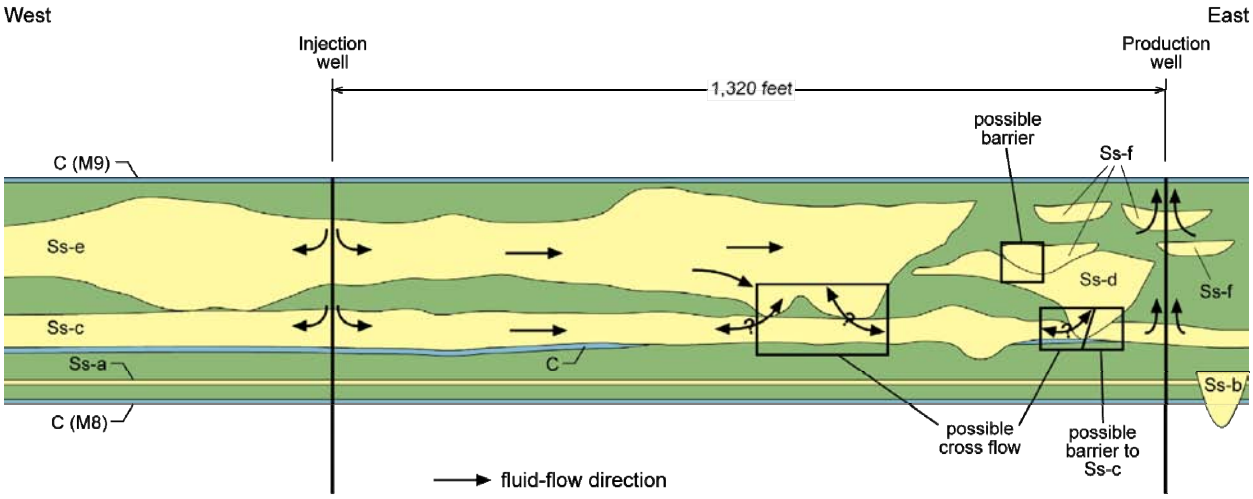


Figure 11-38. Actual two-dimensional correlation and potential fluid-flow pattern between the same two imaginary wells "drilled" at the Nutter's Ranch study site as in figure 11-37. The water-flood effectiveness and the "total oil produced" are much less than in the hypothetical model due to the reservoir heterogeneity. If a barrier exists between Ss-f and Ss-e, and a barrier exists between Ss-d and Ss-c, then oil in Ss-e and most of the oil in Ss-c will not be produced. Oil in Ss-d will also probably not be produced. The production "well" will only produce oil from Ss-f and a very limited amount of oil from Ss-c. See figure 11-35 for location of cross section.

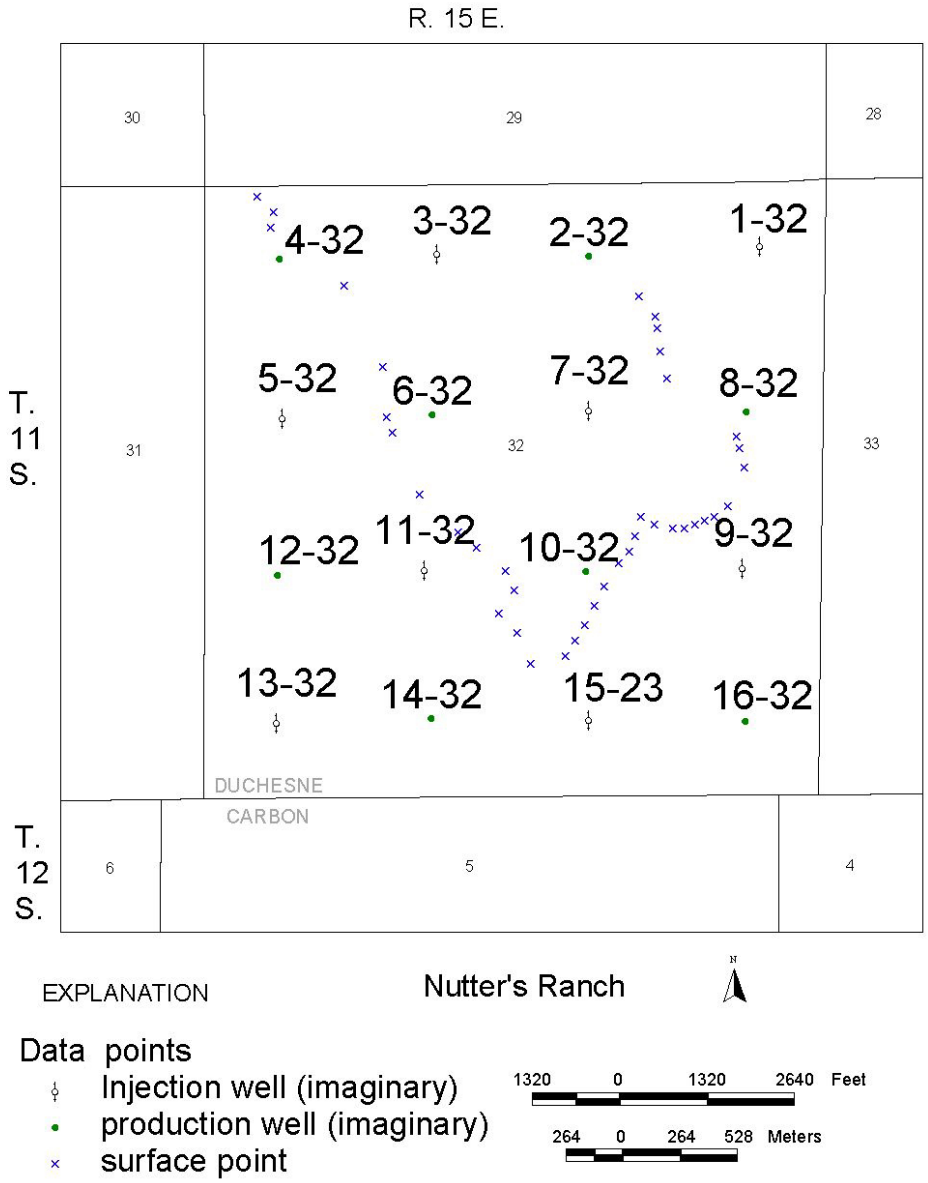


Figure 11-39. Map of the Nutter's Ranch study site with imaginary well locations in the center of 40-acre lots.

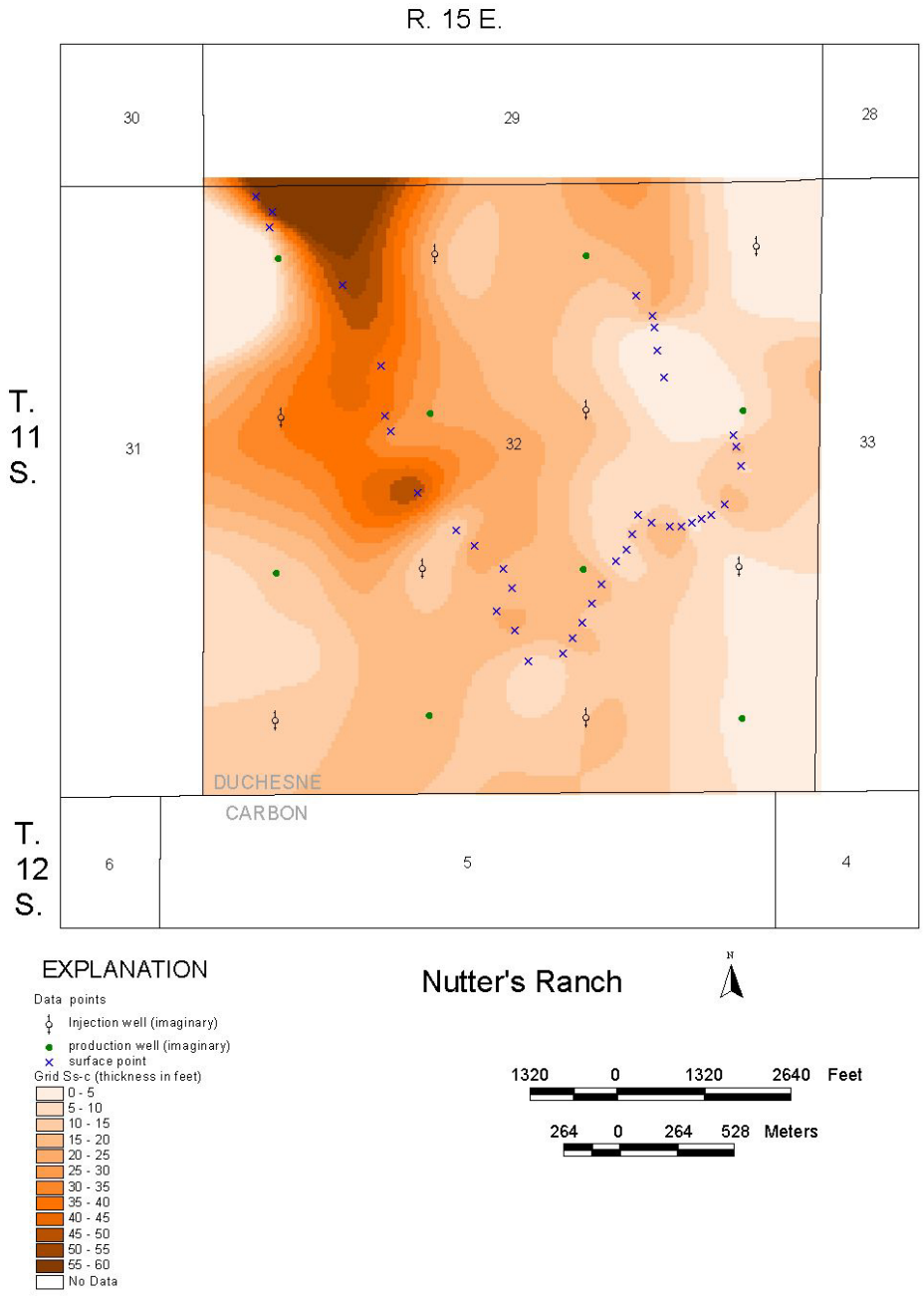


Figure 11-40. Map of Ss-c bed in the Nutter's Ranch study site. Grid interval is 5 feet.

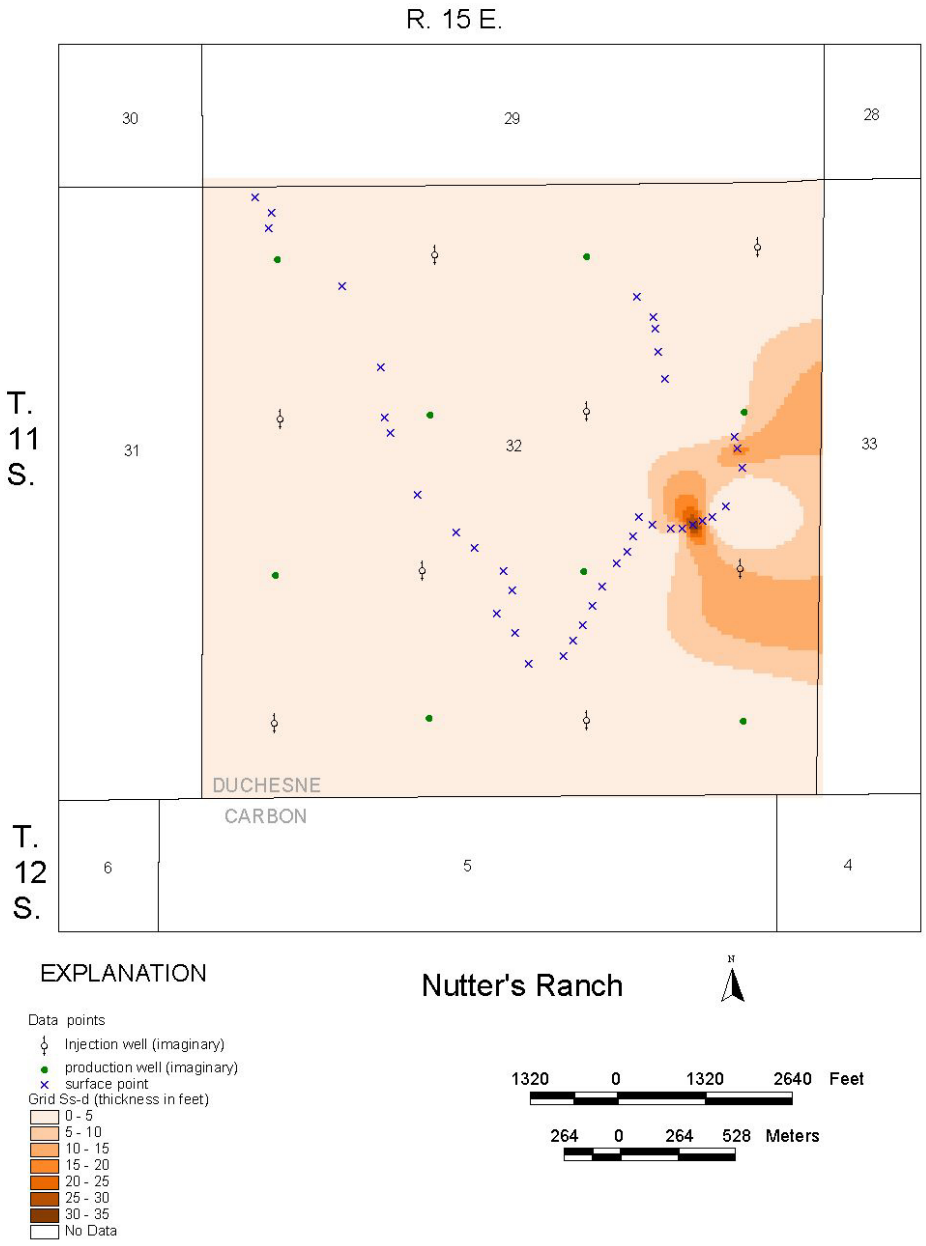


Figure 11-41. Map of Ss-d bed in the Nutter's Ranch study site. Grid interval is 5 feet.

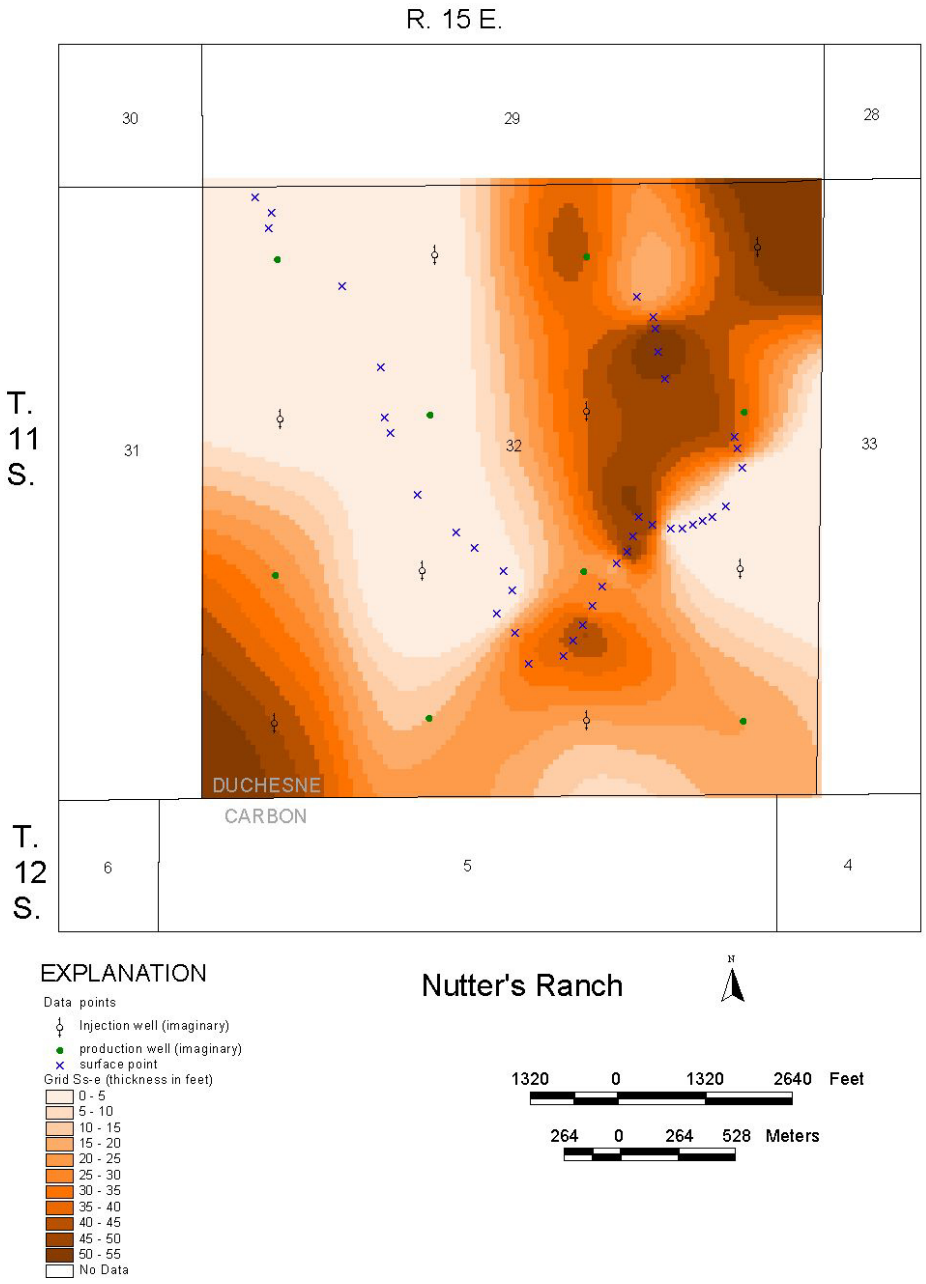
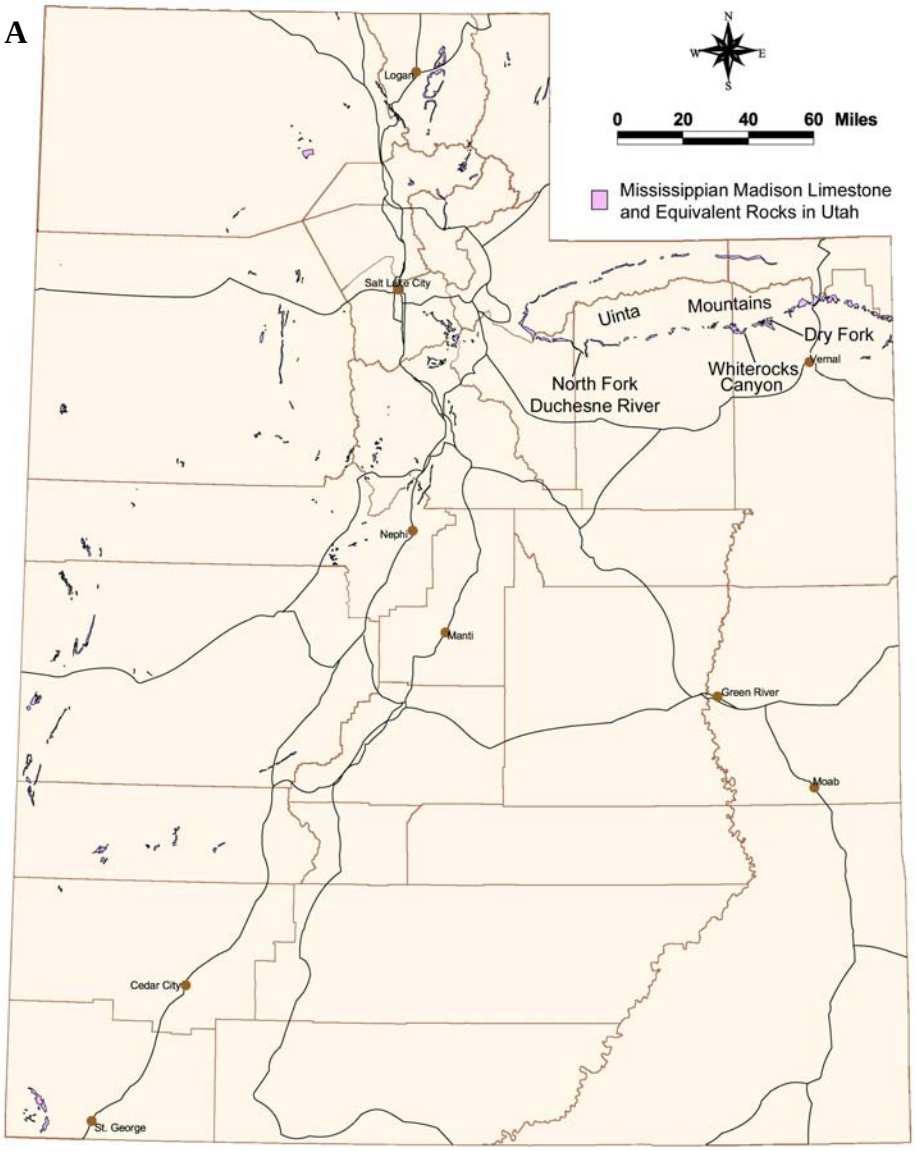


Figure 11-42. Map of Ss-e bed in the Nutter's Ranch study site. Grid interval is 5 feet.

A



B

Age	Formation		Thickness	Lithology
PENN	Morgan Fm	Upper Mbr	600-650'	
		Lower Mbr	150-250'	
	Round Valley Ls		200-350'	
MISS	Doughnut Shale		100-180'	
	Humbug Fm		150-200'	
	Madison Ls		600'	
€	Lodore Fm		400-600'	

Figure 11-43. A - Location of Mississippian rock outcrops in Utah equivalent to the Leadville Limestone. B - Stratigraphic column of a portion of the Paleozoic section along the south flank of the Uinta Mountains (modified from Hintze, 1993).



Figure 11-44. Mississippian Deseret Limestone forming a jagged, vertical cliff, North Fork of the Duchesne River, Duchesne County, Utah. Note the cavernous nature of the outcrop. See figure 11-43A for location of North Fork of the Duchesne River area.

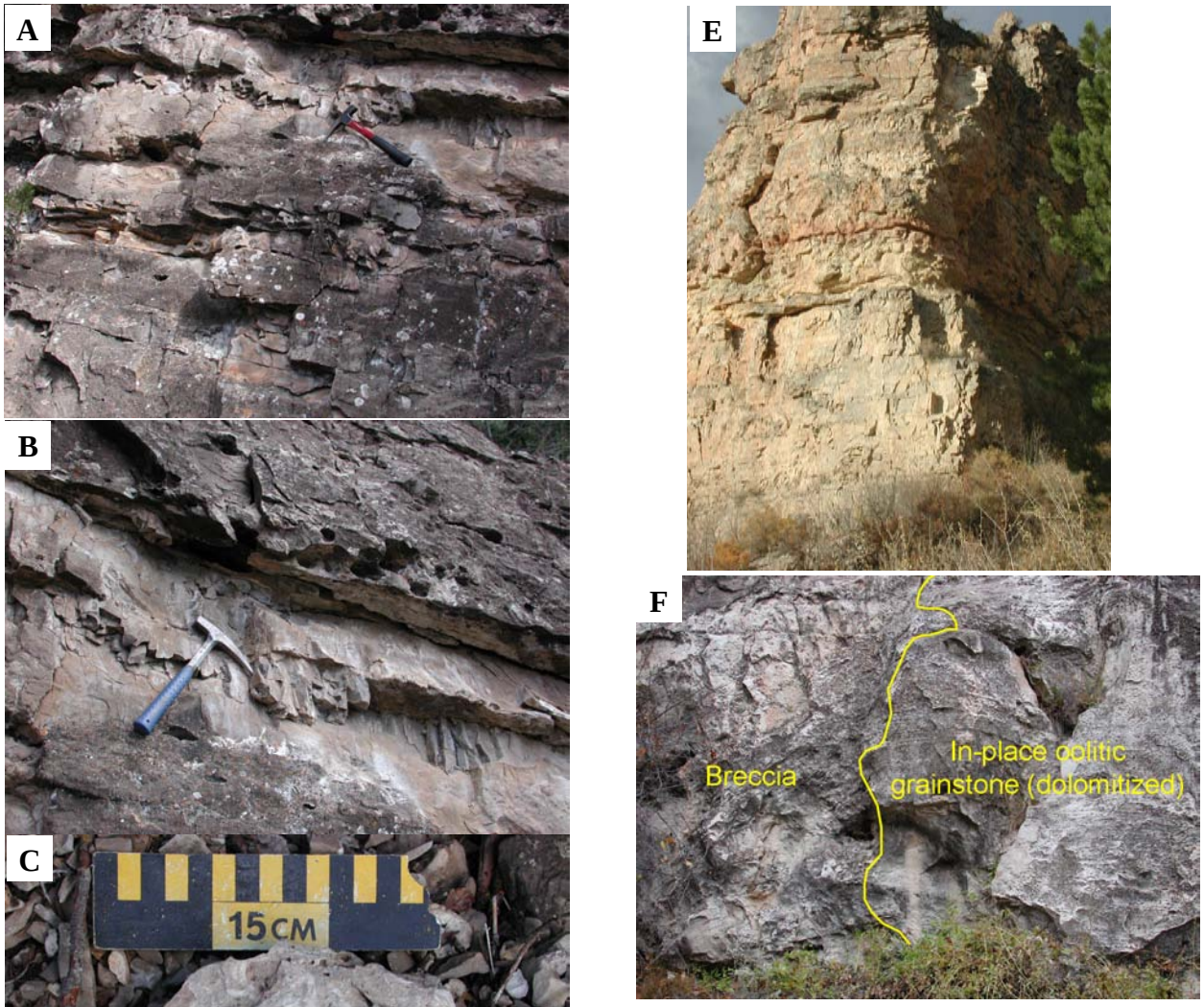


Figure 11-45. Characteristics of the Mississippian Madison Limestone along the south flank of the Uinta Mountains, Uintah County, Utah. A - Typical exposure of light to dark gray, medium bedded, fine to coarse crystalline, limestone and dolomite containing fractures, stylolites, and crinoid hash, Whiterocks Canyon. B - Vugs and fractures in limestone and dolomitic units, Whiterocks Canyon. C - Close-up of open and calcite-filled vugs in limestone matrix, Whiterocks Canyon. D - Close-up of small-scale, calcite-filled rectilinear fractures in limestone matrix, Whiterocks Canyon. E - A combination of interbedded limestone and dolomite, containing fractures and zones of solution breccia and vugs, results in a heterogeneous stratigraphic section, Dry Fork Canyon. F - small-scale oolitic shoal and collapse breccia (outcrop is approximately 10 feet [3 m] high), Dry Fork Canyon. See figure 11-43A for locations of Whiterocks and Dry Fork Canyons.



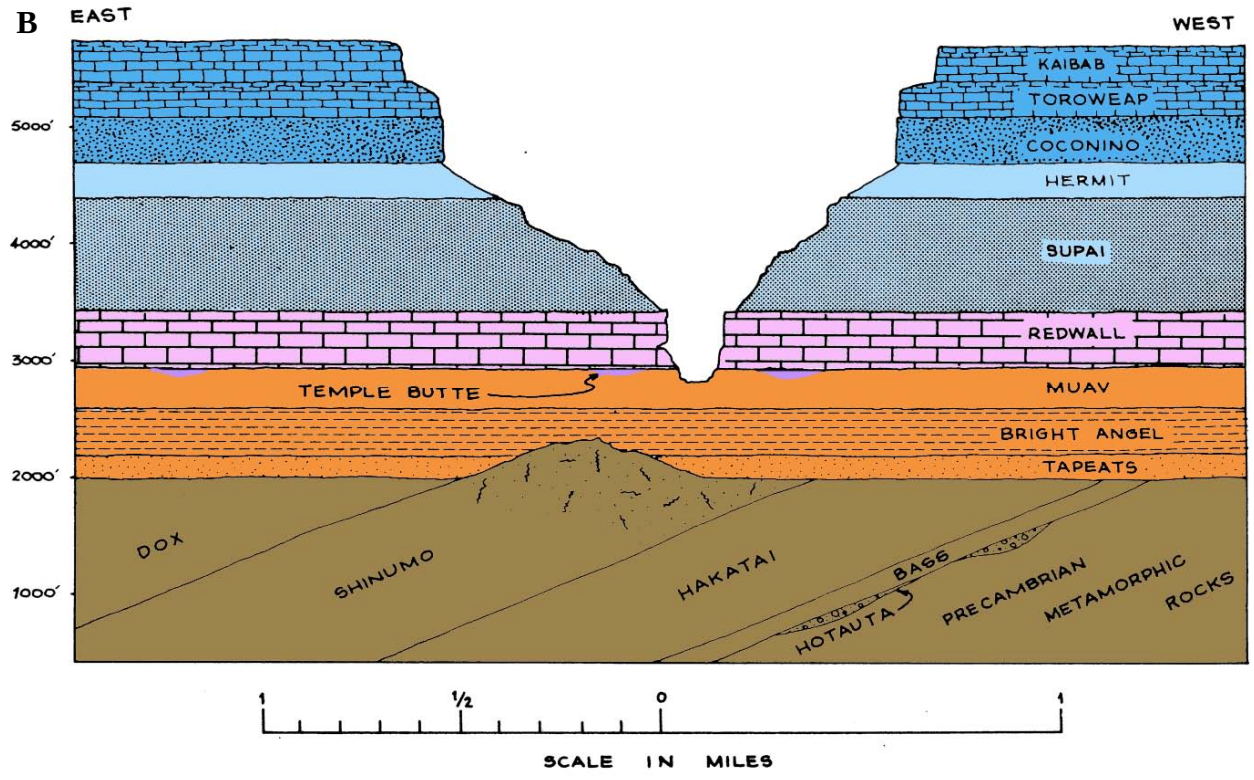


Figure 11-46. River mile 40, Colorado River, Grand Canyon National Park. A – Mississippian Redwall Limestone spectacularly exposed in Marble Canyon, Grand Canyon National Park, Arizona. B – Generalized cross section showing basic stratigraphy and canyon profile in the Marble Canyon (after Hamblin and Rigby, 1968).



Figure 11-47. Location of Marble Canyon in Grand Canyon National Park, Arizona, and major physiographic features (after Hamblin and Rigby, 1968).

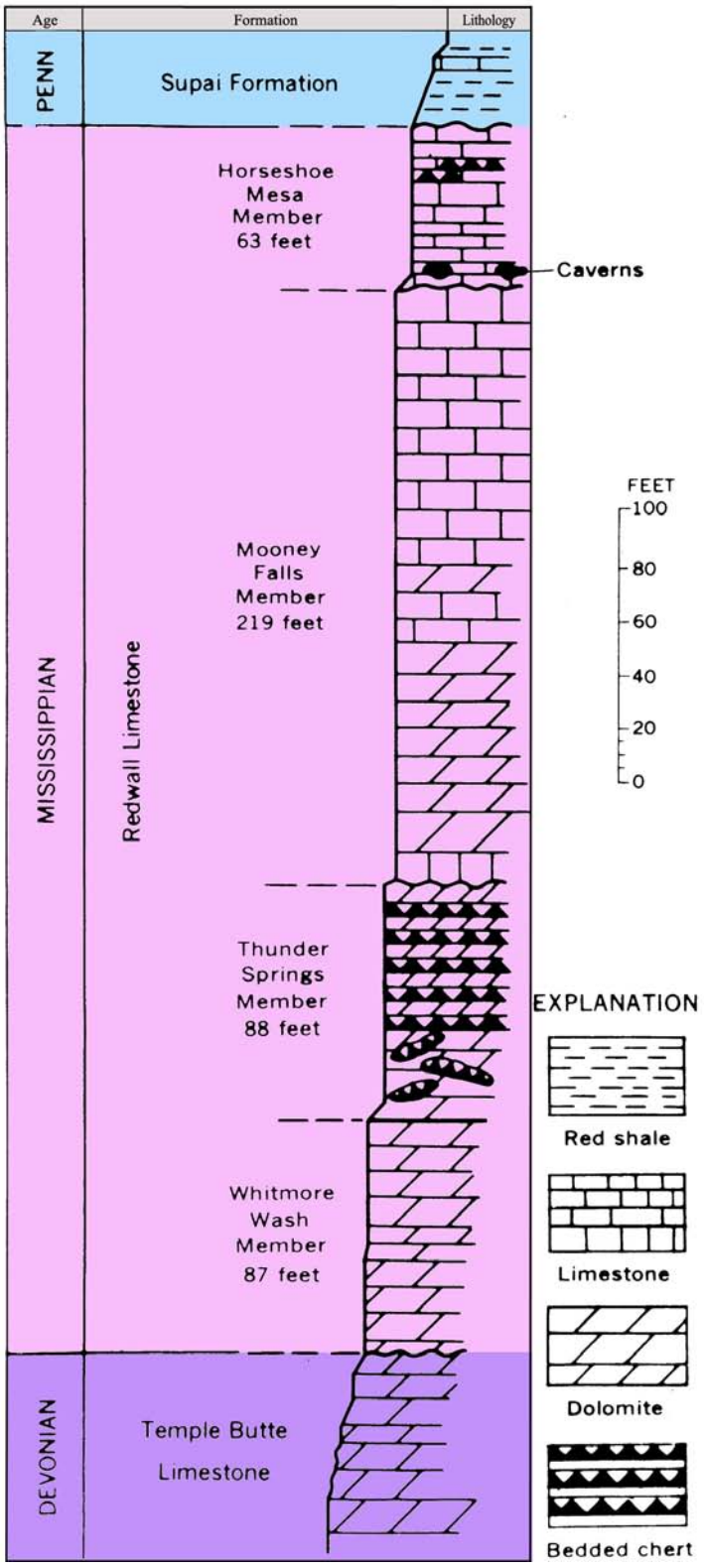


Figure 11-48. Generalized stratigraphic column for the Mississippian Redwall Limestone, Grand Canyon (after McKee, 1969).

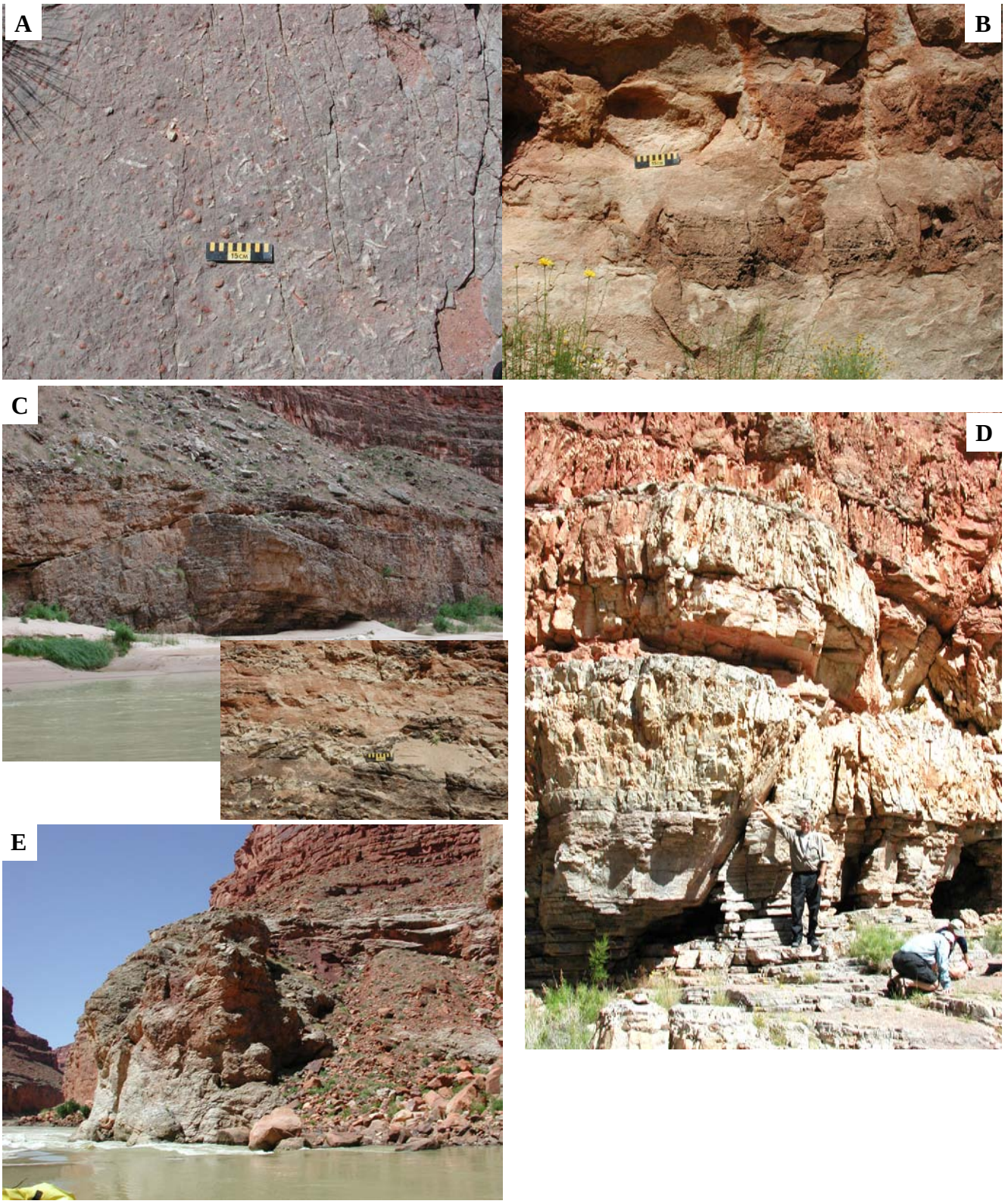


Figure 11-49. General depositional characteristics and structural features of the Redwall Limestone. A – Open-marine facies is represented by corals, brachiopods, and bryozoans; river mile 24.5. B – Cross-bedded crinoid debris (encrinites) that formed shoals or banks; trail to Stanton's Cave along river mile 31.7. C – Waulsortian-type facies buildups consisting of bands of encrinite, containing fenestrate bryozoan, interbedded with chert (inset), near Redwall Cavern; river mile 33. D – Closely spaced, vertical fractures associated with a small fault; river mile 25.5 near Cave Springs Rapid. E – Possible breccia pipe; river mile 26.8 near Tiger Wash.

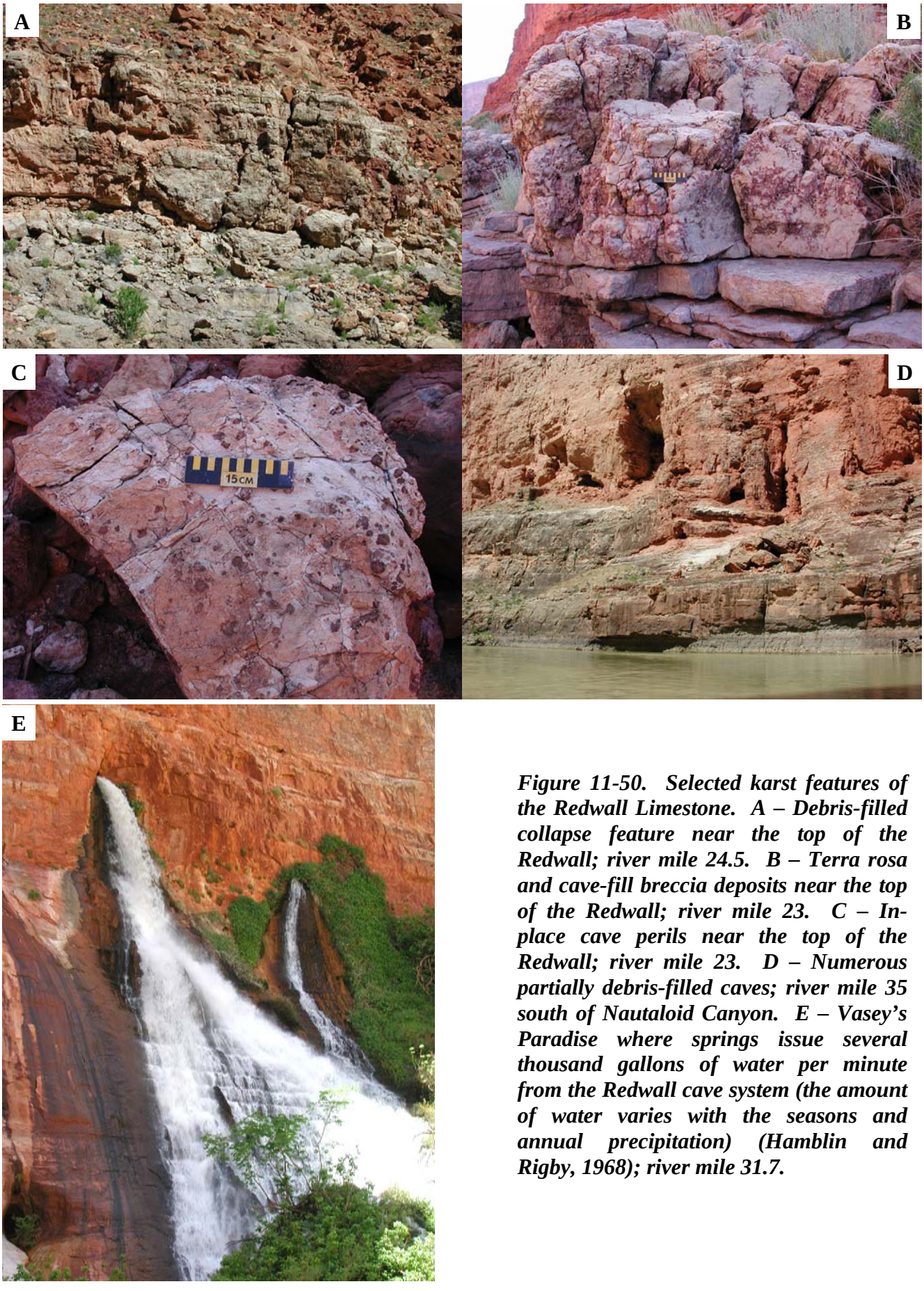


Figure 11-50. Selected karst features of the Redwall Limestone. A – Debris-filled collapse feature near the top of the Redwall; river mile 24.5. B – Terra rosa and cave-fill breccia deposits near the top of the Redwall; river mile 23. C – In-place cave perils near the top of the Redwall; river mile 23. D – Numerous partially debris-filled caves; river mile 35 south of Nautaloid Canyon. E – Vasey's Paradise where springs issue several thousand gallons of water per minute from the Redwall cave system (the amount of water varies with the seasons and annual precipitation) (Hamblin and Rigby, 1968); river mile 31.7.

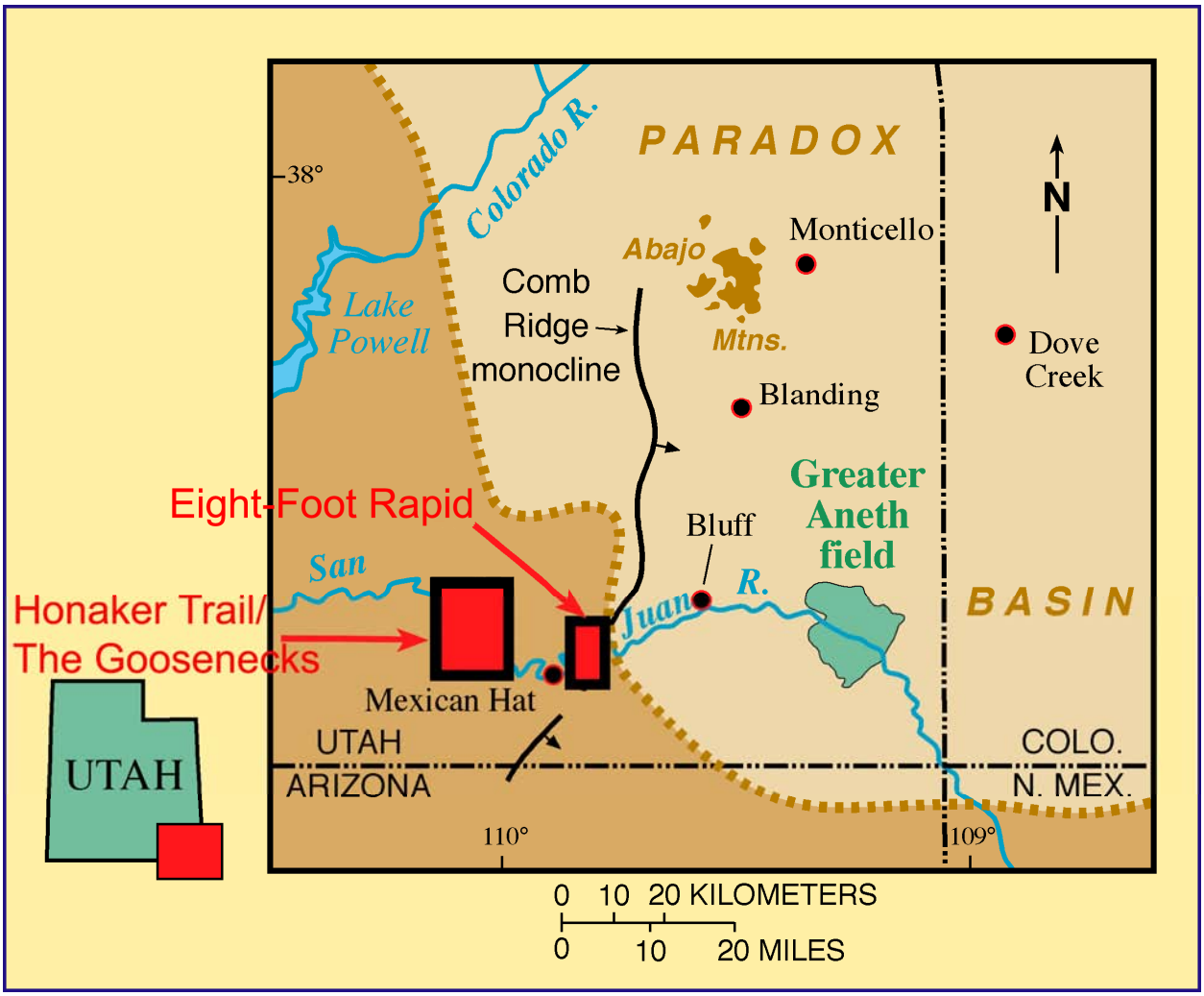


Figure 11-51. Location of Paradox Formation outcrops in the Eight-Foot Rapid area and The Goosenecks/Honaker Trail, San Juan River, southeastern Utah.

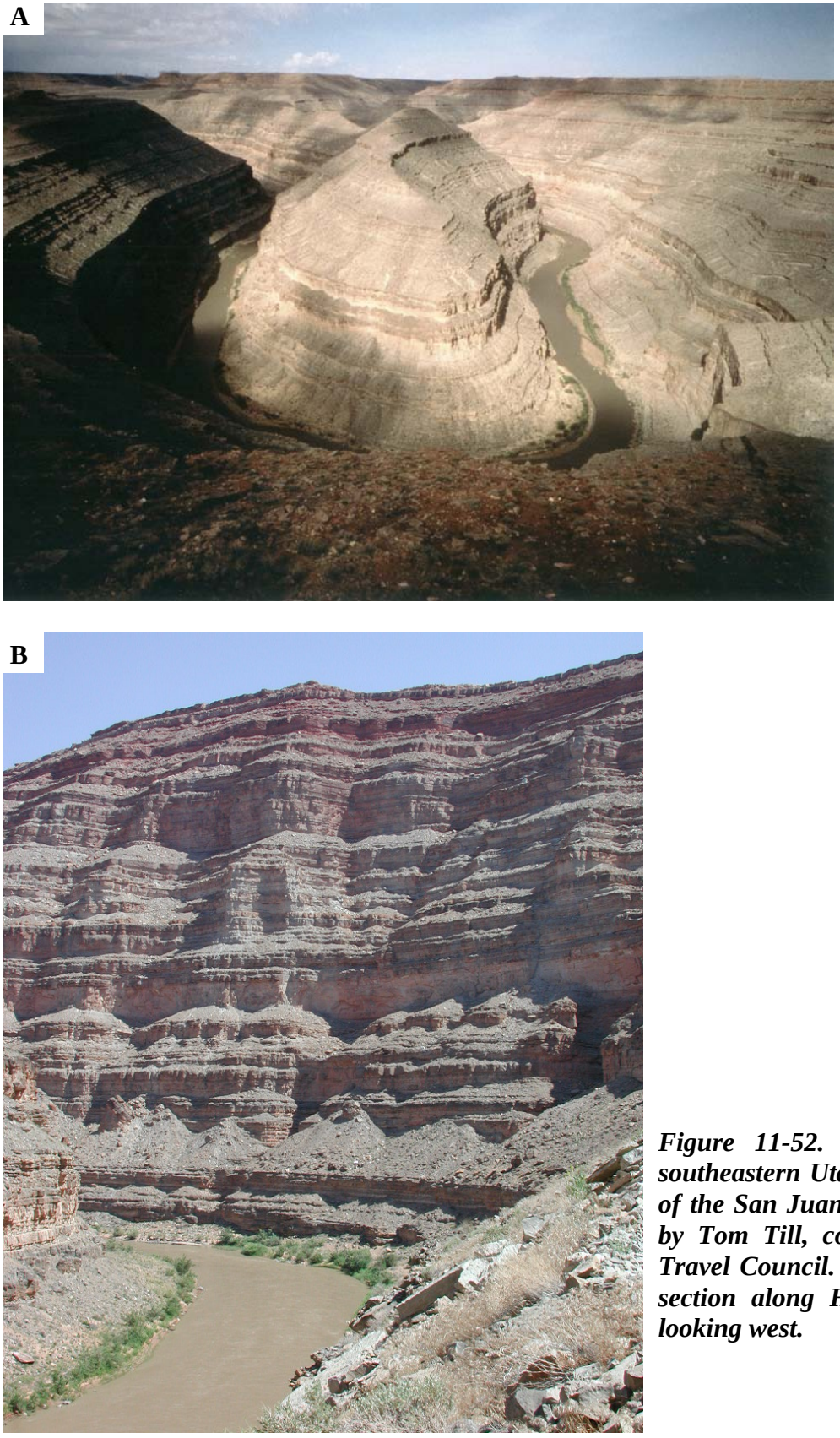


Figure 11-52. San Juan River, southeastern Utah. A – Goosenecks of the San Juan River. Photograph by Tom Till, courtesy of the Utah Travel Council. B – Pennsylvanian section along Honaker Trail, view looking west.

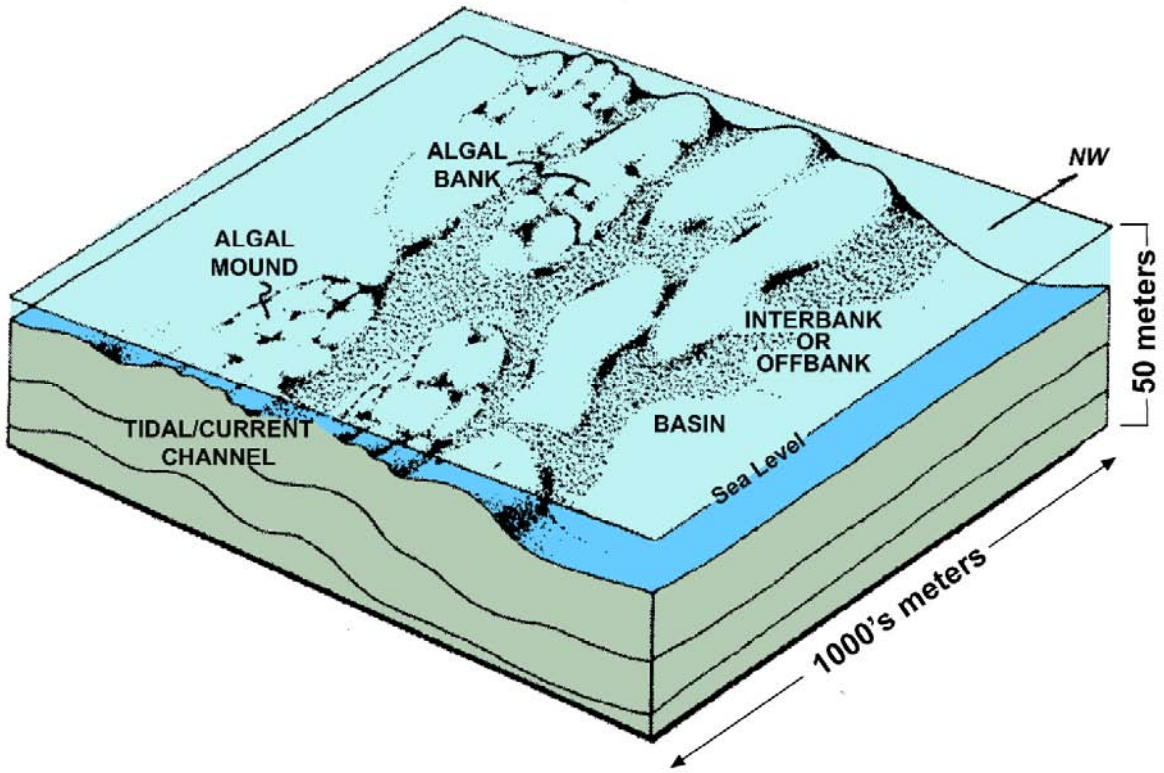


Figure 11-53. Schematic diagram of Paradox Formation algal banks (from Brinton, 1986).

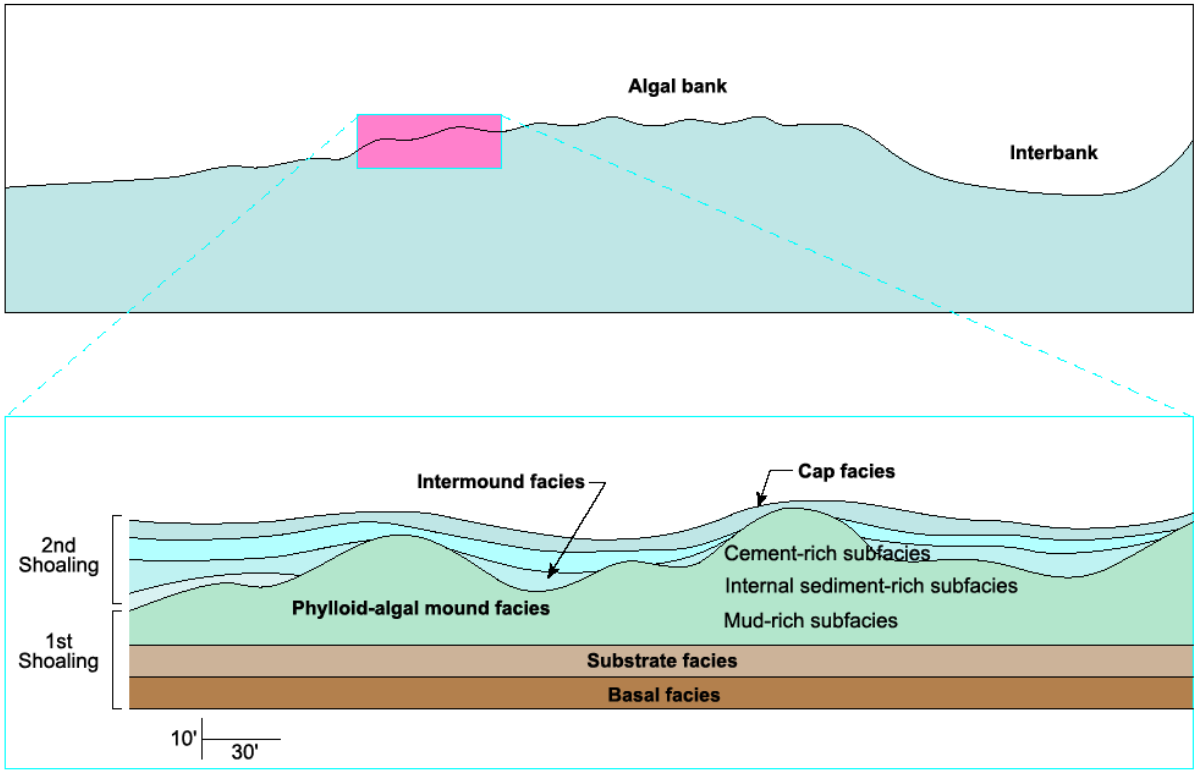


Figure 11-54. Paradox Formation algal bank/mound topography, morphology, and facies relationships as seen along the San Juan River, Utah (from Brinton, 1986).



Figure 11-55. Ismay zone algal banks near Eight-Foot Rapid as illustrated in figures 11-53 and 11-54.

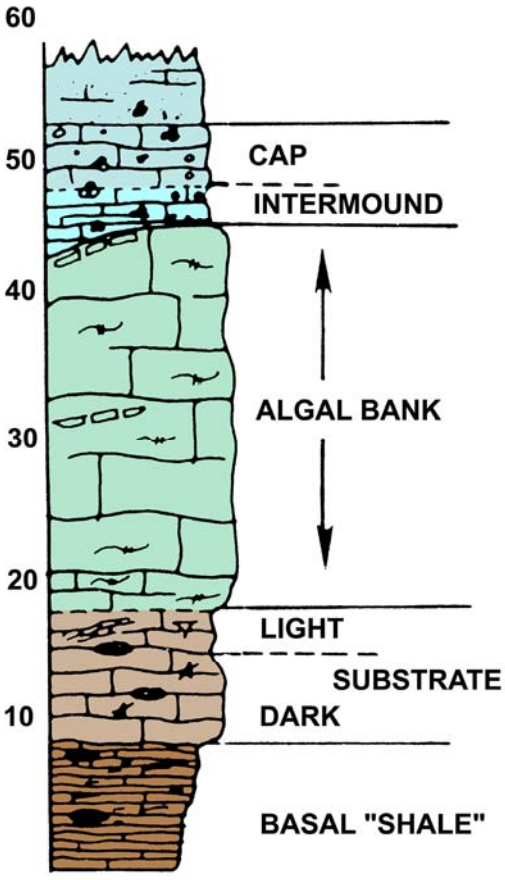


Figure 11-56. Typical vertical facies succession preserved in the Ismay zone at Eight-Foot Rapid (from Brinton, 1986).

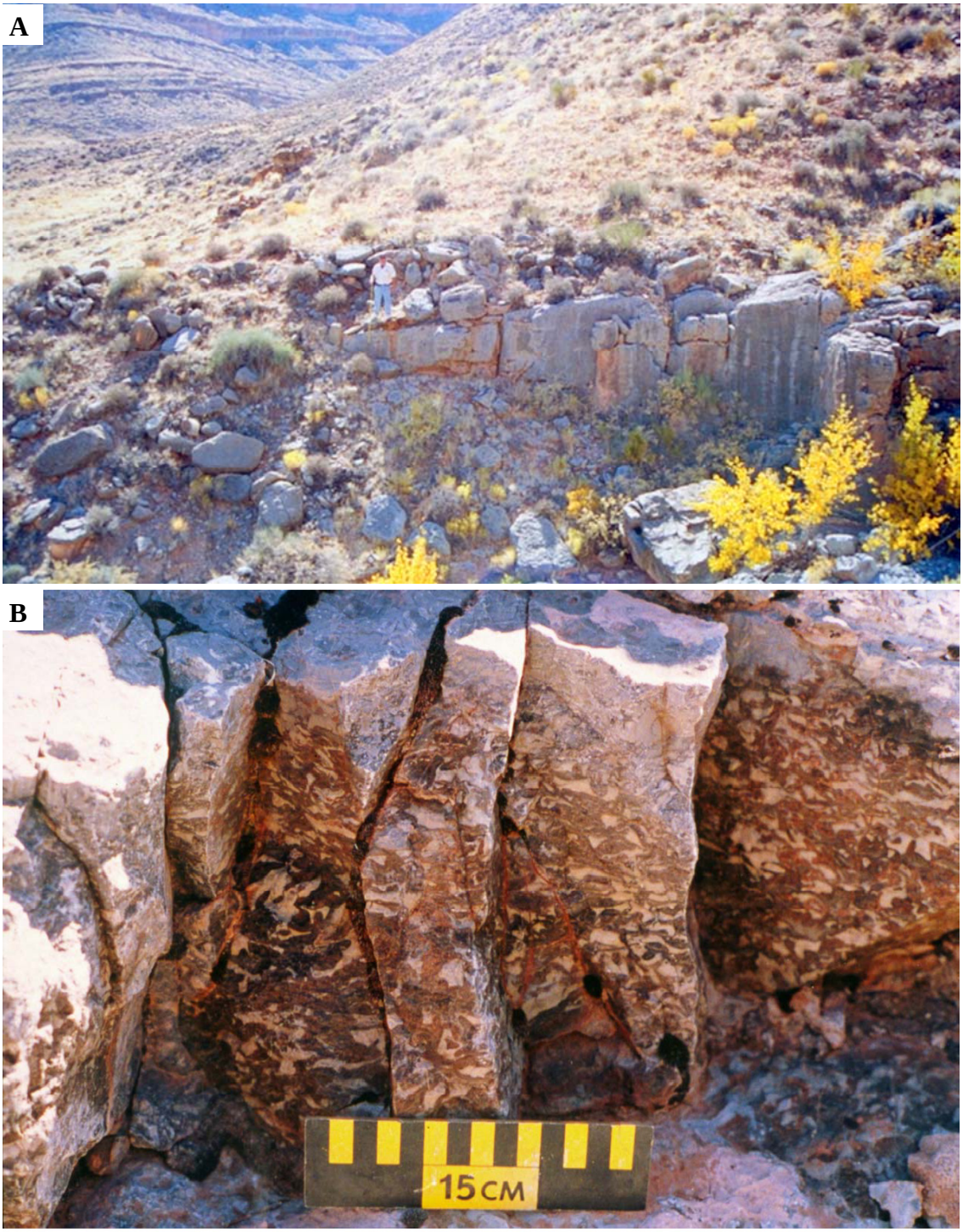


Figure 11-57. Outcrops in the Ismay zone of the Paradox Formation, Eight-Foot Rapid area near the San Juan River, southeastern Utah. A - Typical phylloid-algal mound composed of algal bafflestone, skeletal grainstone, and packstone. A flooding surface is present at the top of the mound. B - Cement-rich algal bafflestone exposed in a phylloid-algal mound. Original sheltered pore spaces were filled with mud; cement rinds are developed around algal plates.

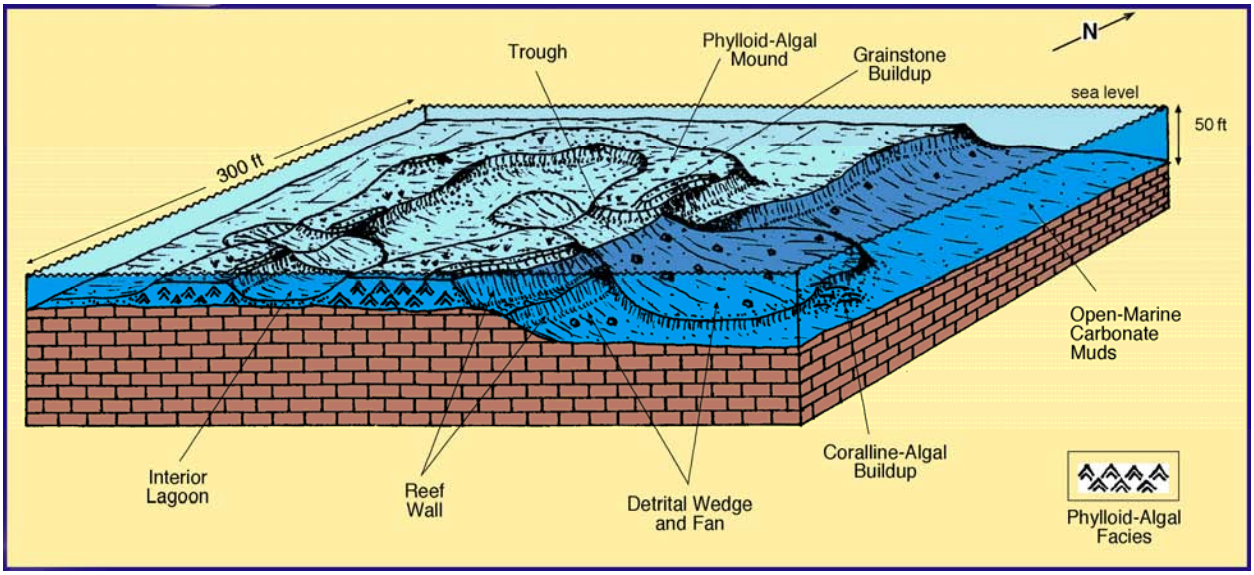


Figure 11-58. Block diagram displaying depositional interpretation of a mound complex and associated features in the Eight-Foot Rapid area (from Chidsey and others, 1996a). This interpretation is a composite of inferences made from outcrop and subsurface data.



Figure 11-59. Flooding surface (4th-order sequence boundary) at the top of the Horn Point marker bed, lower Ismay zone of the Paradox Formation along the Honaker Trail. Note abundant intact and fragmented productid brachiopods in the medium gray limestone matrix.



Figure 11-60. Flooding surface (5th-order parasequence boundary?) at the top of the Barker Creek zone of the Paradox Formation along the Honaker Trail. Note abundant rip-up clasts and sharp contact with the overlying unit.



Figure 11-61. Very fine grained, cross-bedded quartz sandstone near the top of the lower Ismay zone of the Paradox Formation along the Honaker Trail.



Figure 11-62. Large chert nodules in laminated lime mudstone, Akah zone of the Paradox Formation along the Honaker Trail.



Figure 11-63. Chaetetes in fossiliferous wackestone of a skeletal-capping facies, lower Ismay zone of the Paradox Formation along the Honaker Trail.



Figure 11-64. Well-developed cross-bedding in peloidal and oolitic grainstone in the cap and intermound facies of the Barker Creek zone of the Paradox Formation along the Honaker Trail. Close-up shown in inset photo.



Figure 11-65. Small phylloid-algal mound in the Barker Creek zone of the Paradox Formation, river mile 44.3, San Juan River.



Figure 11-66. Medium-sized phylloid-algal mound in the Akah zone of the Paradox Formation, river mile 38.5, San Juan River.



Figure 11-67. Photomosaic of a large phylloid-algal mound complex in the Barker Creek zone of the Paradox Formation, river mile 40.5, San Juan River.

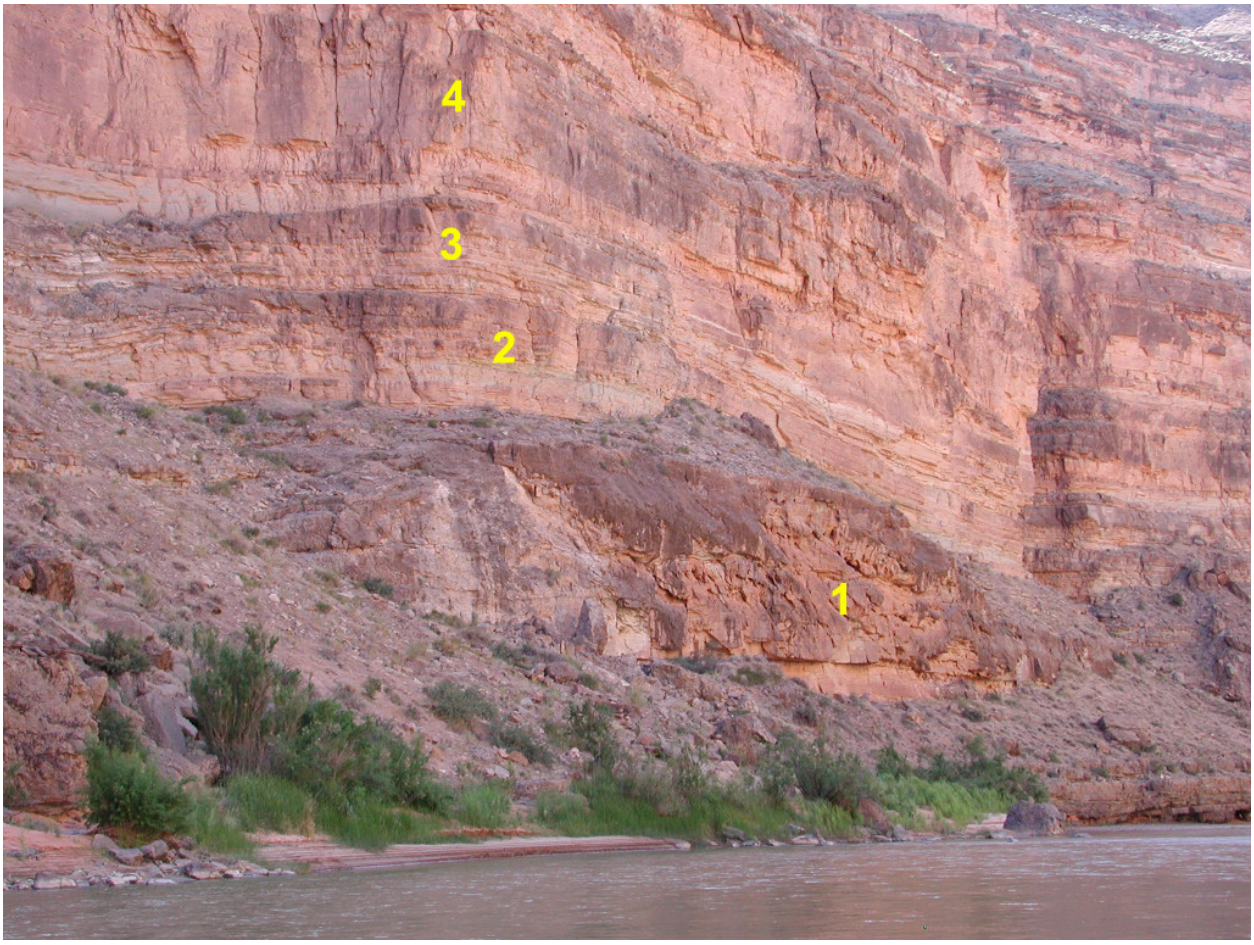


Figure 11-68. Stacked complex of four phylloid-algal mounds in the Akah and Barker Creek zones of the Paradox Formation, river mile 39.8, San Juan River.

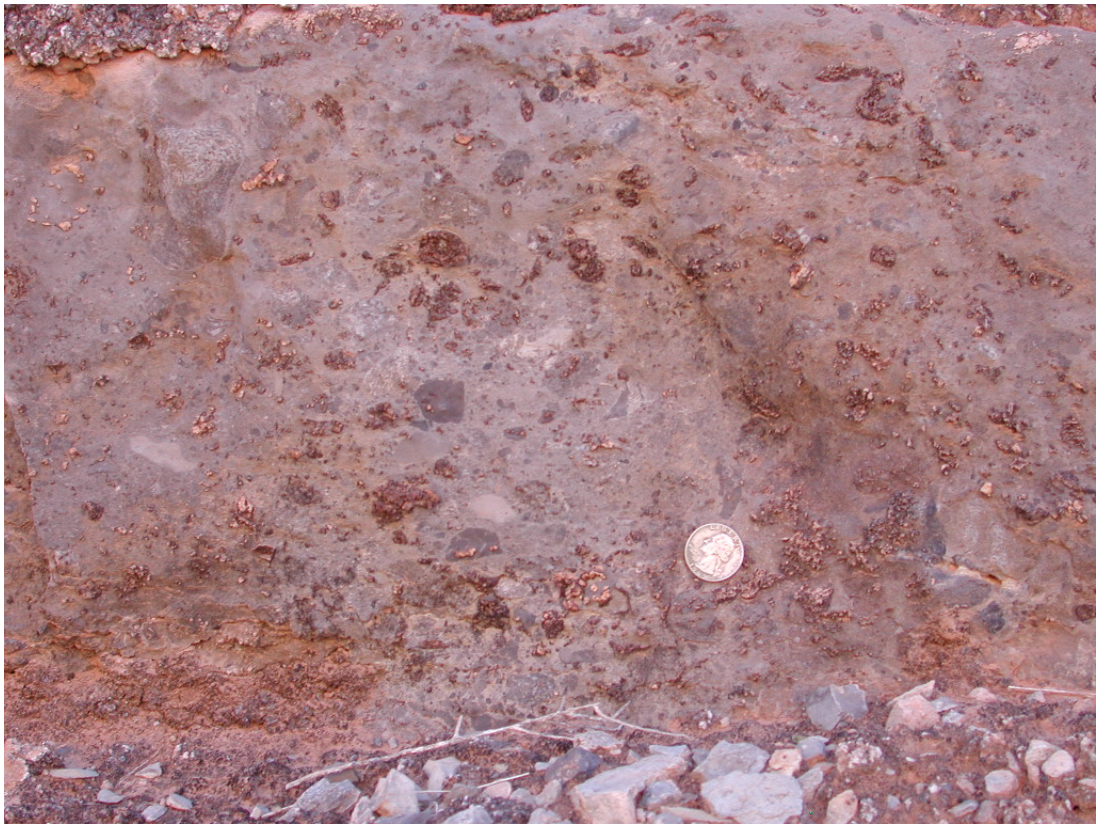


Figure 11-69. Mound flank material – part of the large phylloid-algal mound complex in the Barker Creek zone shown on figure 11-67, river mile 40.5, San Juan River.



Figure 11-70. Cross-bedding in an intermound channel grainstone deposit in the Akah zone of the Paradox Formation, river mile 35.3, San Juan River.

Table 11-1. Lithology, description, and depositional interpretations from the Nutter's Ranch study site.

Lithology (bed designations)	Description	Depositional environment
Carbonate (C)	Oolitic/ostracodal grainstone and micrite, typically contains fossil hash. The beds weather orange.	Lagoonal, beach to shallow nearshore.
Sandstone (Ss-a)	Fine grain, rippled, tabular, thin (<3 feet), laterally continuous except where it is cut by channel sandstone body.	Flood-plain sheet flow.
Sandstone (Ss-b)	Fine grain, deeply incised channel-form bed, trough cross-beds, rip-up clasts and ooids common in lower portion, upper portion some ripples and soft-sediment deformation.	Nonsinuous streams on the upper delta plain.
Sandstone (Ss-c)	Fine grain, channel-form bed, laterally extensive amalgamated channels, planar base due to restrictive carbonate bed preventing downward cutting, promoting lateral migration. Fining upwards with upward decrease in scale of sedimentary structures from trough and low angle cross-beds to planar and rippled. Szantat (1990) Type I sandstone body.	High sinuosity, anastomosing channel deposit in the lower delta plain.
Sandstone (Sd-d)	Fine grain, channel-form bed, laterally limited, incised, individual channel deposit, concave upward lower bounding surface, fining upwards with upward decrease in scale of sedimentary features from lateral accretion beds, trough and low angle cross-bedding to planar and rippled.	Meandering distributary channel.
Sandstone (Ss-e)	Fine grain, channel-form bed, laterally extensive amalgamated channel deposits, concave upward lower bounding surface, fining upwards with upward decrease in scale of sedimentary features from lateral accretion beds, trough and low angle cross-bedding to planar and rippled. Szantat (1990) Type II sandstone body.	High sinuosity, anastomosing channel deposit in the lower delta plain.
Sandstone (Ss-f)	Fine grain, incised channel-form bed, laterally limited, typically inclined trough sets with shale drapes.	Proximal crevasse splay.
Sandstone (Ss-f)	Fine grain, coarsening upward with generally flat top, rippled, thin 1 to 3 feet thick, laterally extensive.	Distal crevasse splay.
Shale and siltstone	Green to gray-green shale and siltstone, typically thinly covered, highly weathered. Some thick covered slopes interpreted to be underlain by shale and siltstone.	Upper and lower delta plain, flood plain to mudflat, to swamp, possibly abandoned channel and overbank deposit.

LAND CLASSIFICATION SUMMARY

CHAPTER 12
LAND CLASSIFICATION SUMMARY

Roger L. Bon,
Utah Geological Survey

Major Land Classifications

Introduction

This land classification summary was prepared using a tool called hypertext markup language (HTML). Hypertext markup language format is used to provide the reader with instant access to all of the Web sites and documents discussed or listed in this report. The reader must have an active Internet browser to take advantage of this tool. Hypertext markup language links are encased in the following brackets < > and/or underlined, and shown in blue print. Placing the cursor over the text and left clicking your mouse button provides access to the appropriate Web sites and or documents. Most of the Web sites were accessed starting in June 2006, and all of the HTML links were current as of May 20, 2007. However, all of the U.S. Bureau of Land Management (BLM) Web sites have undergone reorganization and it is likely that some of the data quoted in this report and HTML links may have changed or been modified, or moved to other parts of the main Web site. Most of the state, county, and local government Web sites are relatively stable although new data and applications are being added and updated frequently.

There is a substantial amount of land, environmental, regulatory, and mineral leasing information on all of the federal Web sites involved in oil and gas leasing and/or regulation. To a lesser extent, similar data are available on most state Web sites. The objectives of this summary are to compile maps and document the major land and mineral ownership types in each oil-producing province in the study area; to identify the federal, state, county, and other private and non-profit agencies involved in the environmental analysis, leasing, and development of oil and gas resources; and to provide an overview and listing of pertinent data, documents, and research tools that might be helpful in understanding the oil and gas industry, primarily in Utah, but also in parts of Arizona, Colorado, and Wyoming.

The Geographic Information System (GIS) data are the most recent data available from statewide databases, but may be dated. The land classification maps should be viewed as approximate and not site specific. The Utah Geological Survey (UGS) has not verified the maps for accuracy. Updated GIS coverages are increasingly being made available online from local BLM Field Offices (FOs). Up-to-date National Forest GIS data are also being made available online at each respective National Forest Web site.

The oil-producing provinces in this study area encompass nearly 15.1 million acres (6.1 million ha) (figure 12-1, table 12-1, and plate 2) and include almost all of the potential oil- and gas-bearing land in Utah and adjacent lands in parts of Arizona, Colorado, and Wyoming. Mineral ownership is divided primarily among federal, state, and private interests. Private interests also include Native American Reservation lands and may include Native American mineral ownership outside an Indian Reservation. Mineral ownership patterns vary among the provinces and dominant ownership is somewhat different in each area. Federal ownership is multifaceted in that while the mineral estate is managed by the BLM, the overlying surface estate might be managed by other federal agencies such as the U.S. Forest Service (USFS), Bureau of

Reclamation (BOR), National Park Service (NPS), or Department of Defense (DOD) in the case of a military reservation. Where the surface estate is managed by another federal agency, the mineral estate may be withdrawn from entry, or surface access is regulated by the surface management agency. This situation is common in National Forests where the FS manages the surface. In other cases, such as military reservations, Wilderness Areas, National Parks and Monuments, and National Recreation Areas mineral entry is limited or has been withdrawn.

The surface estate may also be privately owned, creating a split estate, which is common in the Western U.S. Where this occurs, consultation with the surface owner must take place prior to mineral entry**.** The BLM, in consultation with numerous oil and gas, ranching, and other organizations, has established a set of guidelines for dealing with split mineral estate issues. A discussion of the issue and the resultant set of guidelines is posted on the following BLM Web page : <http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/split_estate.html>. Also, in the Uinta and Paradox Basins, and to a lesser extent the central Utah thrust belt province, there are lands within federally established Indian Reservations. These tribal lands are designated as Native American Reservation lands and the mineral rights are held in trust by the federal government and managed for the benefit of the tribe by the Bureau of Indian Affairs (BIA). There are also other lands within an established reservation where the mineral estate is owned by individual tribal members (allotted lands). Our mapping and ownership analyses do not distinguish between split mineral estate lands and lands where both the surface and mineral estate are owned by the same entity, nor do they show tribal lands owned in fee and/or allotted lands. Native American Reservation land ownership, allotted lands ownership, and lands owned in fee by tribal interests can be obtained from the respective Indian tribe. Contact information for the BIA and Indian tribes is provided in Appendix B.

Records on split mineral estate lands are available at each BLM state office (SO) and at each respective County Recorder's office. In addition, the Utah and Wyoming BLM SOs have recently made available several interactive Web sites where Master Title (MT) plats, historical index sheets, cadastral survey data, and field notes may be viewed online, and many counties in Utah and other states have MT plats available online. An examination of the MT plats will show where split mineral interest occurs.

Land Ownership Data

Surface ownership data for each state were acquired in GIS format from the Internet and are shown on figures 12-1, 12-3 through 12-6, plates 2 through 6. In some instances where surface management data were not current, the GIS files were updated manually. This was necessary where some Wilderness Study Areas, National Monuments, and Primitive Areas have not been integrated with state-wide land management coverage. The agency and Web site for each state is listed below.

Arizona, Arizona BLM, <http://www.blm.gov/az/st/en/prog/maps/gis_files.html>,
Colorado, Colorado BLM, <http://www.co.blm.gov/metadata/cothemes.htm>,
Utah, Automated Geographic Reference Center (AGRC), <http://gis.utah.gov/>, and
Wyoming, Wyoming BLM,
<ftp://ftp.blm.gov/pub/communique/wyweb/gis/datagis.html>.

Surface ownership and cadastral data from Arizona, Colorado, and Wyoming were spliced to the Utah land grid where appropriate.

U.S. Forest Service Lands

The FS is an agency of the U.S. Department of Agriculture, <http://www.fs.fed.us/>, that manages the surface over a large part of the federal land system. The FS has created a Minerals and Geology Management Web page, <http://www.fs.fed.us/geology/>, to help facilitate the energy, mineral, and geologic activities that take place within the National Forest system. The Web page contains a link to a Web page for Energy Leasable Minerals, <http://www.fs.fed.us/geology/mgm_leasable.html>, which provides links to all of the federal legislation (Acts), policies, regulations, planning manuals, and forms related to oil and gas development on FS lands. National Forest lands are identified on figure 12-1 and plate 2, and each National Forest is shown on each oil and gas province map where appropriate. Forest Service lands are leasable for oil and gas, and numerous oil and gas fields are producing within the National Forest system. A listing of National Forests, addresses, and Web site addresses for the four provinces is provided in Appendix C.

U.S. Bureau of Land Management Lands

Bureau of Land Management lands, including FS lands on which BLM manages the minerals, constitute the largest ownership entity in the four oil-producing provinces combined. The BLM is a part of the U.S. Department of Interior <http://www.doi.gov> that is responsible for administering approximately 262 million acres (106 million ha) of the public surface and mineral estates in the U.S. Most of these public lands are located in 12 western states including Alaska. Although the BLM has management responsibility for federal minerals beneath the National Parks, almost all NPS lands are withdrawn from mineral leasing and development. Mineral leasing occurs in a few units of the National Wildlife Refuge system, but most refuge lands are also withdrawn from mineral leasing or have no mineral development potential. Additionally, as part of its trust responsibility, the BLM oversees minerals operations on 56 million acres (23 million ha) of Indian lands.

Bureau of Land Management lands are managed on a national level by federal regulations, on a state level by the statewide administration of federal regulations and state policies, and on a local level by FOs, which are responsible for the day-to-day management and resource planning for federal lands within their areas of responsibility. The Web site for the BLM is <http://www.blm.gov/nhp/>. The Web site contains a plethora of information on federal regulations, land management and planning policies, and activities that affect lands within the national BLM system. All of the policies, regulations, and other data pertinent to planning activity, including oil and gas resource development, are available on the BLM's new Land Use Planning Web site <http://www.blm.gov/wo/st/en/prog/planning.1.html>.

The guidance hierarchy - law, regulations, and policy: The following citation was taken from the Policy section of the BLM Planning Web site as an explanation of how federal law, policy, and regulations form the basis for oil and gas leasing and development.

A three-tiered hierarchy of guidance directs the activities of any federal agency. At the highest level, Congress establishes *law*, which provides mandatory direction to agencies. Because laws are often very broad, agencies generate more specific direction by creating regulations and policies to further define and implement laws. *Regulations* are the second-highest level of direction. When an agency creates new or revises existing regulations, other agencies and the public must review them. Agencies publish their finalized regulations in the Code of Federal Regulations and in the Federal Register. Agencies also issue *policy*, the third level of direction, to provide even more detail to complement laws and regulations. Policies are internal documents that have no external review requirement.

Two key laws influence BLM's planning efforts: the Federal Land Policy and Management Act of 1976 (FLPMA), and the National Environmental Policy Act of 1969 (NEPA).

The BLM Land Use Planning Handbook outlines a process that meets the requirements of both NEPA and FLPMA for the development of planning decisions (new [Resource Management Plans] RMPs and RMP revisions and amendments). The interdisciplinary team established to work on planning projects ensures that the BLM is complying with other laws, regulations, and policies associated with particular resources and uses of the public lands.

Together, NEPA and FLPMA, as well as the associated regulations mentioned above, form the basis for BLM's planning process. BLM's planning handbook is a BLM policy that encompasses the requirements of NEPA and FLPMA laws and regulations.

The chart shown on figure 12-2 depicts this framework. The following links are available to access laws, regulations, and policy involved in BLM land-use planning and implementation.

Laws:

Federal Land Policy and Management Act of 1976 <http://www.blm.gov/flpma>

National Environmental Policy Act of 1969 <http://ceq.hss.doe.gov/Nepa/regs/nepa/nepaeqia.htm>

Regulations:

43 CFR 1600 (BLM Land Use Planning Regulations) <http://www.access.gpo.gov/nara/cfr/waisidx_02/43cfr1600_02.html>

40 CFR 1500-1508 (CEQ guidance on implementing NEPA) <http://www.blm.gov/wo/st/en/info/nepa.3.html>

Policy:

BLM National Planning Manual <http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/blm_manual.html>

BLM National Planning Handbook <http://www.blm.gov/wo/st/en/info/nepa.3.html>

BLM NEPA Handbook <http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/blm_handbooks.print.html>

Branch of Fluid Minerals: The BLM Branch of Fluid Minerals, which is under the Division of Fluid Minerals is responsible for the adjudication, administration, and maintenance of oil and gas, combined hydrocarbon, and geothermal steam authorizations approved on federally owned mineral estates.

Bureau of Land Management state office Web sites: Access to each state's planning activities and schedules is available through links provided in the Web site header. For example, on the BLM Utah Web site, left click Programs and then Planning on the left side of the web page and you will be directed to the Resource Management Planning home page. From subsequent web page links, you can access individual Web sites for each of the active RMPs. Each RMP Web site provides documentation of the planning activity and the results of many studies, including maps, that were conducted for each planning area. If a Draft or Final Environmental Impact Statement (EIS), a requirement of the planning process, and Approved RMP are available, those documents will be posted on the Web site.

Many other resources are available on BLM State Office Web sites such as the BLM Directory page <http://www.blm.gov/wo/st/en/info/directory.2.html>, which provides contact information and links to all state and other BLM offices nationwide. State BLM Web sites contain policy and regulatory information including land-use planning documents and maps (many in GIS format), schedules, and personnel contacts. State BLM Web sites for Arizona, Colorado, Utah, Wyoming, and other western states that are active in oil and gas leasing also contain environmental and regulatory data on oil and gas leasing, a 12-month rolling list of oil and gas lease sale activity, and the results of the two most recent lease sales.

Overview of leasing on public lands: Federal agencies involved in mineral leasing activities are listed in Appendix D. The basic requirements for lease operations are outlined in Onshore Order #1. The link to this order is <http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/Onshore_Order_no1.html>. The following description of the Federal Onshore Oil and Gas Leasing System is taken from the Federal Onshore Oil and Gas Leasing System Web site that was accessed May 20, 2007.

Introduction

> The Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act for Acquired Lands of 1947, as amended, give the Bureau of Land Management (BLM) responsibility for oil and gas leasing on about 570 million acres of BLM, National Forest, and other Federal lands, as well as private lands where mineral rights have been retained by the Federal Government. The BLM works to assure that development of mineral resources is in the best interests of the Nation.
>
> Regulations that govern the BLM's oil and gas leasing program may be found in Title 43, Groups 3000 and 3200, of the Code of Federal Regulations, a publication available in law libraries and most large public libraries. A copy may also be obtained from any BLM State Office.

Lands Available for Leasing

Public lands are available for oil and gas leasing only after they have been evaluated through the BLM's multiple-use planning process. In areas where development of oil and gas resources would conflict with the protection or management of other resources or public land uses, mitigating measures are identified and may appear on leases as either stipulations to uses or as restrictions on surface occupancy.

Lessee Qualifications and Limitations

Federal oil and gas leases may be obtained and held by any adult citizen of the United States. No lease may be acquired by a minor, but a lease may be issued to a legal guardian or trustee on behalf of a minor. Associations of citizens and corporations organized under the laws of the United States or of any State also qualify.

Aliens may hold interests in leases only by stock ownership in U.S. corporations holding leases and only if the laws of their country do not deny similar privileges to citizens of the United States. They may not hold a lease interest through units in a publicly traded limited partnership.

Types of Oil and Gas Leases

The BLM issues two types of leases for oil and gas exploration and development on lands owned or controlled by the Federal Government - competitive and noncompetitive.

The Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and not received a bid.

The maximum competitive lease size is 2560 acres in the lower 48 States and 5760 acres in Alaska. The maximum noncompetitive lease size in all States is 10,240 acres.

Since passage of the Energy Policy Act of 1992, both competitive and noncompetitive leases are issued for a 10-year period. Both types of leases continue for as long thereafter as oil or gas is produced in paying quantities.

Competitive Leasing Process

Oral auctions of all oil and gas leases are conducted by most BLM State Offices not less than quarterly when parcels are available. A Notice of Competitive Lease Sale, which lists lease parcels to be offered at the auction, will be published by each BLM State Office at least 45 days before the auction is held. Lease stipulations applicable to each parcel are specified in the Sale Notice.

Lands Included in the Sale Notice Come from Three Sources:

(1) Parcels identified by informal expressions of interest from the public or by the BLM for management reasons; or

(2) Lands included in offers filed for noncompetitive leases.

All auctions are conducted with oral bidding. Bidders must attend the auction to obtain a competitive lease or provide for someone to represent them. No sealed or mailed bids are accepted.

On the day of the auction, the successful bidder must submit a properly executed lease bid form, which constitutes a legally binding lease offer, and pay a share of the sale costs ($75 per lease); the first year's advance rental ($1.50 per acre or fraction thereof); and not less than the $2-per-acre minimum bonus bid. The balance of the bonus bid must be received within 10 working days of the auction. Those bidders who fail to submit the balance of the bonus on time will forfeit their entire deposit money.

Lease Terms and Conditions

The lease grants the lessee the right to explore and drill for, extract, remove, and dispose of oil and gas deposits, except helium, that may be found in the leased lands.

Subject to special restrictions as noted above, the leases are granted on the condition that the lessee will have to obtain BLM approval before conducting any surface-disturbing activities. The oil and gas lease conveys the right to develop those resources on the leased land. The lessee or his/her operator cannot build a house on the land, cultivate the land, or remove any minerals other than oil and gas from the leased land.

Bonding

Before any surface-disturbing activities related to drilling can begin, the lessee or his/her operator must furnish a bond in the amount of at least $10,000 to ensure compliance with all the lease terms, including protection of the environment. With the consent of the surety and principal, the operator may use the bond of another party such as the lessee. Each time there is a new operator, that operator must notify the BLM that he/she is the responsible operator, giving the particulars of the bond under which he/she will operate.

Acceptable instruments of bonding are surety bonds, or personal bonds accompanied by negotiable Treasury securities, cashier's check, certified check, certificate of deposit, or irrevocable letter of credit. The BLM may require an increase in the bond amount any time conditions warrant such an increase.

Rentals

Annual rental rates for both competitive and noncompetitive leases are $1.50 per acre (or fraction thereof) in the first 5 years and $2.00 per acre each year thereafter. After the lease is issued, rentals must be received at the Department of the Interior's Minerals Management Service (MMS) on or before the lease anniversary date to prevent statutorily required automatic termination of the lease. This requires mailing of the annual rental at least a week or 10 days in advance of the lease anniversary date to ensure timely receipt by the MMS.

Royalties

Royalty on production is 12.5% for both competitive and noncompetitive leases.

Assigning a Lease

Some people who acquire an oil and gas lease will assign the lease to another party. The value of oil and gas leases varies greatly. None of the parcels offered has been evaluated by the BLM for oil and gas potential prior to the competitive auction or to being made available for noncompetitive leasing. All of the lands included in noncompetitive leases have been offered at auction and received no bids.

Leases may be transferred by assignment or sublease. The transfer must be submitted to the BLM for approval within 90 days from the date of execution by the transferor. The rights of any transferee will not be recognized by the Government, and the transferor will remain responsible for the lease, until the transfer has been approved by the BLM. An assignment either of a separate zone or deposit or of part of a legal subdivision will not be approved. An assignment of less than 640 acres outside of Alaska or of less than 2560 acres within Alaska will be approved by the BLM only if the assignment constitutes the entire lease or is demonstrated to further the development of oil and gas.

How a Lease Expires or Terminates

Oil and gas leases expire at the end of their primary term – the 10th year – unless diligent drilling operations are in progress on or for the benefit of the lease; the lease contains a well capable of producing oil or gas in paying quantities; or the lease is receiving or is entitled to receive an allocation of production under the terms of an approved communitization agreement or unit agreement.

Leases without a producible well automatically terminate if the lessee fails to make full and timely payment of the annual rental. The rental must be received by the proper Federal office on or before the anniversary date of the lease. The automatic termination is specifically prescribed by law, is not the result of BLM action, and cannot be waived.

> The owner of a lease also may surrender the lease in whole or in part by filing a written relinquishment with the proper BLM State Office having jurisdiction over the lands. A relinquishment takes effect on the date it is filed. However, the lessee must plug any abandoned well, perform other work as may be required by the BLM to place the leasehold in proper condition for abandonment, and bring his/her account into good standing. If the lessee fails to perform the necessary work, the lessee's bond will be used to do so, and the lessee will be prohibited from leasing any additional Federal lands.
>
> A nonproducing lease may be canceled for failure to comply with lease terms.

Oil and gas leasing sale notices and sale results: Lease sales are posted on the individual BLM SO websites. The tentative dates for upcoming lease sales are also posted on the Web page. The following related topics can be searched on each states website.

(1) Sale Notices and Sale Results,
(2) General O & G Leasing Instructions,
(3) Non-Competitive Offers,
(4) Submitting an Expression of Interest (EOI),
(5) Leasing FAQS for Industry,
(6) General Oil and Gas Leasing FAQs,
(7) 43 CFR 3100 Oil and Gas Leasing,
(8) 43 CFR 3110 Noncompetitive Leases,
(9) 43 CFR 3120 Competitive Leases, and
(10) Forms.

Best Management Practices for Oil and Gas Development on Public Lands

Following issuance of a lease and before exploratory drilling can begin, the leaseholder must submit an Application for Permit to Drill (APD). This application process is very rigorous and comprehensive. The application of Best Management Practices (BMPs) in oil and gas leasing is defined in the new *Gold Book*, a joint effort of the BLM and FS.

> The new BLM and FS *Gold Book* (the former *Gold Book* had not been updated in over 15 years) introduces improved practices for expediting the processing of APDs and environmental Best Management Practices to reduce the environmental effect of energy exploration and production. The revised *Gold Book* includes updated drawings, photographs, tables, and references to updated policy, orders, and regulations.

The preceding citation was taken from the Web site <http://www.blm.gov/bmp/goldbook.htm>. The Web site also contains downloadable versions of the new *Gold Book* and information to order up to two free, printed copies of the handbook.

Bureau of Land Management Web-Based Tools

Oil and gas lease maps and surface and mineral land status maps can be created through the BLM's National Integrated Land System (NILS) <http://www.blm.gov/nils/>.

> NILS is a joint project between the BLM and the FS in partnership with the states, counties, and private industry to provide business solutions for the management of cadastral records and land parcel information in a GIS environment. The NILS provides a process to collect, maintain, and store parcel-based land and survey information that meets the common, shared business needs of land title, and land resource management. The NILS project is being developed in four modules: *Survey Management* (S), *Measurement Management* (M), *Parcel Management* (P), and *GeoCommunicator* (G).
>
> The NILS provides the user with tools to manage land records and cadastral data in a "Field-to-Fabric" manner. The user can use field survey measurement data directly from the survey measuring equipment, manipulate the data into lines and points, and create legal land and parcel descriptions to be used in mapping and land record maintenance.

The preceding citation was taken from the NILS Web site.

> GeoCommunicator is the publication site for NILS and provides searching, accessing, and dynamic mapping of data for federal land stewardship, land and mineral use records, and land survey information. GeoCommunicator provides spatial display for land and mineral cases from BLM's LR2000 system.

The preceding citation was taken from the GeoCommunicator Web site. Additional information on GIS data are available from the Land Survey Information System Web site**,** <http://www.geocommunicator.gov/GeoComm/lsis_home/home/index.html>, which is linked to GeoCommunicator. Most of these Web sites are relatively new and are frequently updated. In addition, the Utah and Wyoming BLM SOs have recently made available an interactive Web site for searching Master Title Plats and Historical Index Sheets, and Cadastral Surveys and Field Notes. The data are available through links in the Public Room or Information Access Center Web page on each state's Web site. The Web address for Arizona is http://www.blm.gov/az/st/en.html. The Web address for Utah is <http://www.blm.gov/ut/st/en.html>. The Web address for Wyoming is < http://www.blm.gov/wy/st/en.html>. Colorado is working on making its MT plats and Cadastral Survey data available online, although it is not known when these data will be available.

Bureau of Land Management State Offices

The BLM SO serves as an information center and provides oversight and support for each of its FO's. State offices are responsible for conducting oil and gas and other mineral leasing activities on lands within each state's jurisdiction. For this study, which includes lands in Arizona, Colorado, Utah, and Wyoming, the Web sites for each BLM SO are:

Arizona <http://www.blm.gov/az/st/en.html>,
Colorado <http://www.co.blm.gov/>,
Utah <http://www.ut.blm.gov/>, and
Wyoming <http://www.blm.gov/wy/st/en.html>.

Each BLM FO is responsible for the day-to-day management of lands and related activities within its area of responsibility. Field offices are also responsible for conducting and updating Land Use Plans (LUPs) and RMPs that provide the basic framework on how federal lands and resources (renewable and nonrenewable) are utilized. Resource Management Plans are used to designate lands suitable for oil and gas and other mineral leasing and identify lands that are suitable for leasing, but may have some restrictions for surface occupancy. Land Use Plans and RMPs are administered under federal policies that apply system-wide, so that the same process and procedures apply to BLM lands in Utah as well as all other states. In recent years, RMPs have become the more common method for land and mineral resource planning. An explanation of the planning process and links to existing LUPs and RMPs are provided on each BLM SO's Land Use Planning Web site. These Web sites are as follows:

Arizona <http://www.blm.gov/az/st/en/prog/planning.html>,
Colorado <http://www.co.blm.gov/nepa/landplan.htm>,
Utah <http://www.blm.gov/ut/st/en/prog/planning.1.html>, and
Wyoming <http://www.wy.blm.gov/planning/index.htm>.

Updates on BLM planning projects are also provided. The resource planning issue has become so important in recent years that each RMP that is being developed or updated has its own Web page.

Overview of Utah's Bureau of Land Management Planning

Since the majority of land within the four oil-producing provinces described earlier in this report is in Utah, much of the following narrative is taken from the BLM Utah Web site or from various BLM Utah FO Web sites. Similar data can be found for any of the oil-producing province's public lands in Arizona, Colorado, and Wyoming.

> Managing approximately 23 million surface acres of public land, BLM-Utah realizes public involvement in our [BLM] management strategies is critical. Planning emphasizes a collaborative environment in which local, State, and Tribal governments, as well as the public, user groups, and industry work with the BLM to identify appropriate multiple uses of the public lands.
>
> The land-use planning process allows for extensive public involvement and provides a blueprint of how the public land should be managed. BLM Utah's mission is to sustain the health, diversity and productivity of the public land, and land-use planning is a vital to our mission.

Field offices: The addresses of BLM FO's are listed in the summaries for each oil-producing province. The BLM lands in Colorado are managed as follows: Mesa County - Grand Junction FO, <http://www.co.blm.gov/gjra/gjra.html>; Montrose County and the northeastern part of San

Miguel County - Uncompahgre FO, <http://www.co.blm.gov/ubra/index.html>, and lands in the rest of San Miguel County, and Dolores and Montezuma Counties - Mancos/Dolores joint BLM/USFS office (no Web site) in Dolores, Colorado. The BLM lands in Utah are managed as follows:

Fillmore FO, <http://www.ut.blm.gov/fillmore_fo/> - Juab and Millard Counties,
Moab FO, <http://www.blm.gov/ut/st/en/fo/moab.html> - Grand County,
Monticello FO, < http://www.blm.gov/ut/st/en/fo/monticello.html > - San Juan County,
Price FO, <http://www.blm.gov/utah/price/> - Carbon and Emery Counties,
Richfield FO, <http://www.blm.gov/ut/st/en/fo/richfield.html> - Garfield, Piute, Sanpete, Sevier, and Wayne Counties,
Salt Lake FO, <http://www.ut.blm.gov/saltlake_fo/> - Morgan, Rich, Summit, Utah, and Wasatch Counties, and
Vernal FO, - <http://www.blm.gov/ut/st/en/fo/vernal.html> - Duchesne and Uintah Counties.

The Paradox Basin lands in Arizona are within the Navajo Indian Reservation and oil and gas leasing there is administered by the BIA.

Data availability: Documentation for each LUP and RMP is available on each BLM SO Web site and local FO Web sites. In addition to copies of all LUPs and RMPs, EISs, Environmental Assessments (EAs), and other NEPA-required documentation are available at each BLM SO through its Information Access Center (also called Public Room). In addition, many of the documents can be ordered on compact disk (CD) from the SO. Each BLM SO Web site is organized independently, but each Web site has links to, or contains, all of the pertinent data relating to environmental planning, oil and gas leasing and development, and environmental protection and/or remediation.

All NEPA documentation for Utah is available on the new Environmental Notification Bulletin Board (ENBB) Web site <https://www.blm.gov/ut/enbb/index.php>, which provides for notice of all BLM actions occurring in each of the Utah FOs that are subject to NEPA regulation. An explanation on how to use the Web site and its search features is provided on the Web site.

Resource management planning within the oil-producing provinces:

Some of Utah's RMPs that are under revision have been identified by the BLM as 'Time Sensitive Resource Management Plans' to timely address energy resources studied under the Energy Policy and Conservation Act (EPCA). In Utah, these include the Price and Vernal RMPs.

Under EPCA, signed into law by former President Clinton in 2000, federal agencies were tasked with developing a national inventory of all oil and gas resources and reserves beneath federal lands. This data is now being incorporated into RMPs to plan for multiple uses on the public lands, and specifically plan for the responsible development of energy resources in these areas.

The EPCA report examines oil and gas resources of five major geologic basins in the West, three of which are partially located in Utah (Uinta/Piceance, Paradox/San Juan, and the Greater Green River Basins). In the EPCA, Congress

requested that the study not only provide an estimate of oil and gas resources and reserves, but also information on any constraints that may limit development of these energy resources.

Use of the EPCA study in planning for Utah's federally managed lands is crucial to meeting the rising energy demands of the state. Since the majority of the region relies on locally generated oil, [coal], and natural gas to [run transportation], heat homes, and provide electricity, these local resources are necessary [to] prevent the additional costs and environmental impacts associated with importing resources from other states. Although many of Utah's oil and gas wells only generate average production, the cumulative production meets the needs of the region and reduces future dependency on foreign supplies.

In the planning process, the EPCA inventory will be used to determine oil and gas leasing stipulations and lease restrictions. It will also be used to determine criteria for waivers, exceptions, and modifications. In some cases the review may result in strengthening stipulations or lessening stipulations dependent upon the current conditions being addressed. Reviewing the stipulation information cannot supersede any of the laws and regulations that BLM must already follow.

The planning process for mineral development has and will continue to involve the public. BLM is working in a collaborative manner with stakeholders to ensure responsible development of mineral resources. Integrating the EPCA inventory during the planning process will lay a foundation for sound management decisions that meet the nation's rising energy demands while protecting other important resources.

In addition to oil, gas and coalbed natural gas, the RMPs will also address solid mineral development (such as coal) and renewable energy resources (geothermal, wind, etc.). Energy development requires various types and durations of land use, from temporary staging areas used only a few days or weeks, to facilities that may be present for 30 years or more. These uses and impacts will also be addressed in the plans. Most of these areas can be restored to a near natural state after energy resources are extracted.

The preceding citation was taken from the Energy section of the Utah BLM Land Use Planning Web site <http://www.blm.gov/ut/st/en/prog/planning.1.html>. For more information on EPCA and planning efforts see the Utah RMP Web sites.

In general, planning activity within the four oil-producing provinces can be accessed via each SO or FO Web site. The links for each of the provinces are listed in the following sections.

Utah/Wyoming thrust belt – There is no new planning activity within the Utah/Wyoming thrust belt province. For the Utah portion of the area, public lands are managed by the Salt Lake FO, <http://www.ut.blm.gov/saltlake_fo/> under two Management Framework Plans (MFPs). The first is the Randolph MFP that was approved in 1980. The link to that document is <http://www.ut.blm.gov/planning/RANDOLPHMFP.PDF>. The second is the Park City MFP that was approved in 1974. A summary of the decisions relative to that plan is found in a document titled Park City Land Use Decisions and Highlights. The link to that document is <http://www.ut.blm.gov/planning/PARKCITYSUM.PDF>. Thrust belt lands in Wyoming are

managed by the Kemmerer FO, <http://www.wy.blm.gov/kfo/index.htm>. The new Kemmerer RMP was released in August 2008, and the RMP and related documents are can be found on the following Web site: <http://www.blm.gov/rmp/kemmerer/>.

Central Utah thrust belt — Hingeline – All of the lands in the central Utah thrust belt province are in Utah and public lands are managed by several BLM FOs. Public lands in most of the province (Piute, Sanpete, and Sevier Counties) including the newly discovered Covenant field are managed by the Richfield FO, <http://www.blm.gov/ut/st/en/fo/richfield.html>. Public lands in Utah County are managed by the Salt Lake FO, <http://www.ut.blm.gov/saltlake_fo/>, and public lands in Juab and Millard Counties are managed by the Fillmore FO, <http://www.ut.blm.gov/fillmore_fo/>. A relatively small part of the province in Beaver County is managed by the Cedar City FO, <http://www.ut.blm.gov/cedarcity_fo/>. The Richfield FO has recently developed a new RMP, <http://www.blm.gov/rmp/ut/richfield/>. The RMP Web site contains the RMP, and numerous maps and documents related to the many environmental studies involved in the planning process. No new RMPs are being developed for province lands managed by the Salt Lake and Fillmore FOs. The current LUP for lands managed by the Salt Lake FO is the Bear River East Plan Amendment EA, 1994. The document is not available online, but can be viewed at the BLM SO or at the Salt Lake FO. The current RMP for lands managed by the Fillmore FO is the House Range Resource Area Amended Resource Management Plan <House Range RA ARMP/ROD & RPS; 1987>. In addition to the House Range Amended RMP, the House Range Resource Management Plan Oil and Gas Lease Implementation Environmental Assessment was approved in 1988. This document is not available online, but is available for review at the BLM SO or the Fillmore FO.

Uinta Basin – There is a substantial amount of planning activity in the Uinta Basin of Utah and Colorado. The majority of the Uinta Basin province is in Utah and is managed by the Vernal FO, <Vernal Field Office>. A new RMP, covering Daggett, Duchesne, and Uintah Counties, which had been in the planning process since March 2001, was released in October 2008. The link to the Vernal RMP is <http://www.blm.gov/rmp/ut/vernal/>. Uinta Basin public lands in Colorado are managed by the White River FO. The link to the White River FO is <http://www.co.blm.gov/wrra/index.htm>. Planning activity to amend the White River FO Oil and Gas RMP is located at <http://www.blm.gov/rmp/co/whiteriver/>. The planning process began in June 2006 and is scheduled for completion in spring 2011.

Paradox Basin – The Paradox Basin province is largely in southeastern Utah, but also includes a significant amount of land in southwestern Colorado, and, to a lesser extent, Navajo Nation lands in Arizona. Oil and gas leasing on Navajo Nation lands in Arizona and Utah is administered by the BIA office in Window Rock, Arizona, in agreement with the Navajo Nation. Contact information is available on the Navajo Nation's Division of Natural Resources Web page <http://www.dnr.navajo.org/DNR/staff.htm>. Contact information for the BIA's Window Rock, Arizona office is included in Appendix B. Paradox Basin province lands in Utah are managed by several BLM FOs, including Moab, Monticello, Price, and Richfield. Work on a new RMP for the Moab FO has been ongoing since 2003, and the new RMP was released in October 2008. Planning documentation and links to the new Moab RMP are available at the following Web site: <http://www.blm.gov/rmp/ut/moab/>. Likewise, planning for a new RMP for the Monticello FO was initiated in June 2003, and the new RMP was approved in November 2008. Planning

documentation and the RMP are available on the RMP's Web site <http://www.blm.gov/rmp/ut/monticello/>. A planning document titled "Reasonable Foreseeable Development Scenario for Oil and Gas" was released July 1, 2005, and is available at <http://www.blm.gov/pgdata/etc/medialib/blm/ut/monticello_fo/_planning/rmp/rfd.Par.52638.File.dat/RFD.pdf>. The Price FO released its Draft RMP/Draft Environmental Impact Statement (EIS) in July 2004 and the public review of the document ended in November 2004. The Record of Decision and the new RMP was released in October 2008. Planning documentation and the new Price RMP is available at <http://www.blm.gov/rmp/ut/price/>. The Richfield FO has also released a new RMP. Planning was initiated in 2001 and the Record of Decision and the new Richfield RMP was released in October 2008. The Web site for the Richfield RMP is <http://www.blm.gov/ut/st/en/fo/richfield/planning.html>.

Wilderness Area, Wilderness Study Area, and Instant Study Area Lands

One Wilderness Area (WA), 30 Wilderness Study Areas (WSAs), and three Instant Study Areas (ISAs) are in two (Uinta Basin and Paradox Basin) of the four oil-producing provinces. These lands are identified within each oil province where they occur (see plates 5 and 6). Withdrawal orders for WAs are identified on MT plats. Wilderness Study Areas and ISAs have not been officially withdrawn from mineral entry, but are protected under the authority of Section 603 of FLPMA and managed according to the Interim Management Policy and Guidelines for Lands under Wilderness Review (IMP, BLM Manual Handbook H-8550-1) to preserve their wilderness values until Congress either designates them as Wilderness or releases them for other uses. A summary of WAs, WSAs, and ISAs is included in Appendix E. The identification and selection of additional areas in Utah that have Wilderness characteristics and the debate over Wilderness has been ongoing for more than 20 years. The following overview of the history of the Wilderness issue on public lands in Utah is taken from the Utah BLM Wilderness Web site <http://www.access.gpo.gov/blm/utah/pdf/intro.pdf>.

> For more than 20 years, debate has raged over the identification and management of certain public lands in the State of Utah, and whether some areas should have been designated for wilderness study as part of the original inventory process required by the 1976 Federal Land Policy and Management Policy Act (FLPMA). FLPMA sets forth the basic principles and procedures the federal Bureau of Land Management (BLM) must follow in the management of public lands. Following its enactment, BLM initiated a westwide inventory of public lands to determine areas with wilderness characteristics, as defined by the 1964 Wilderness Act.
>
> There were three stages in that process: an initial inventory to select lands for further consideration, the identification of lands with wilderness characteristics, and recommendations for Congressional designation or release based on "suitability" and 'manageability,' as judged by BLM and the Administration at the time.
>
> Charges that the BLM improperly omitted qualifying areas in the original inventory led to protests and appeals, hearings before Congress, legislative proposals to protect the disputed areas, and the most intractable controversy over any resource inventory since the passage of FLPMA.

During this time, Utah wilderness became the subject of national debate, with members of both parties attempting to pass legislation to resolve the issue. Despite many years and numerous efforts, none have yet succeeded. In a June 1996 letter to Representative James Hansen of Utah, Chairman of the Public Lands Subcommittee of the House Resources Committee, Interior Secretary Bruce Babbitt observed that "an important reason for this stalemate is that the various interests involved are so far apart on the threshold, fundamental issue of how much BLM land has wilderness characteristics in the state."

Accordingly, the Secretary directed that a six-month administrative field review of the lands in question be conducted to assess conditions on the ground two decades after the first inventories began. In the same letter to Representative Hansen, the Secretary reported that the team undertaking the review was 'explicitly instructed to apply the same legal criteria that were used in the original inventory, and to consider each area on its own merits, solely to determine whether it has wilderness characteristics. The team will have no particular acreage target to meet; the chips will fall where they may.'

The inventory team began gathering information in July 1996, and field work was initiated in September 1996. In October 1996, the State of Utah, the Utah State Institutional Trust Lands Administration, and the Utah Association of Counties filed suit in federal district court in Utah, challenging the Secretary's authority to conduct the reinventory. In November 1996, the federal district court issued a temporary restraining order barring further work on the inventory. The United States complied with the injunction, but appealed the decision to the Tenth Circuit Court of Appeals. In March 1998, the Tenth Circuit reversed the district court on all counts relating to the inventory.

In deciding the case, the Court referred to the 'plain language' of Section 201 of FLPMA, which says: 'The Secretary shall prepare and maintain on a continuing basis an inventory of all public lands and their resource and other values (including, but not limited to, outdoor recreation and scenic values), giving priority to areas of critical environmental concern. This inventory shall be kept current so as to reflect changes in conditions and to identify new and emerging resource and other values. The preparation and maintenance of such inventory or the identification of such areas shall not, of itself, change or prevent change of the management or use of public lands.' On June 19, 1998, the injunction was lifted and the inventory team was asked to reassemble, finish the field work and write the following report.

Secretarial Direction

As Secretary Babbitt wrote to the Senate Appropriations Committee in 1996, 'This is a narrowly focused exercise directed at a unique problem: the extraordinary 20-year-old Utah wilderness inventory controversy.' The Secretary's instructions to the BLM were to 'focus on the conditions on the disputed ground today, and to obtain the most professional, objective, and accurate report possible so we can put the inventory questions to rest and move on.' He asked the BLM to assemble a team of experienced, career professionals

and directed them to apply the same legal criteria used in the earlier inventory and the same definition of wilderness contained in the 1964 Wilderness Act.

The Secretary asked the team to review the written public record on the subject of Utah wilderness, including information and materials generated by both the state and federal government during the past 20 years. The team was then to undertake a comprehensive 'ground-truthing' field review, using proposed legislation before Congress (HR 1500 and HR 1745) to identify the areas for examination. Conditions on the ground would determine whether the boundary lines of the inventory unit exactly followed those specified in the proposed legislation, or were adjusted based on the presence or absence of wilderness characteristics.

From the outset, the Secretary gave clear instruction that the process would be strictly limited to the administrative identification of lands with wilderness characteristics based on established legal definitions. The team would not make recommendations regarding legislative designations of wilderness areas or the creation of new wilderness study areas. Because FLPMA provides that only Congress can abolish existing wilderness study areas created as a result of the initial inventory nearly two decades ago, the team was also instructed not to review lands within wilderness study areas.

No public hearings or meetings were held during this phase. The BLM was directed to complete the administrative document and field review and to report the results to the Secretary. Secretary Babbitt said that after the report was made public, he would consider initiating a Legislative Environmental Impact Statement and/or a FLPMA Section 202 planning process that could lead to recommendations to Congress or to changes in the status of certain lands studied during the inventory process.

If those steps are taken, the Secretary promised the opportunity for public input in any resulting process. Until then, the BLM was explicitly instructed not to change the management of any lands within the inventory areas based on the results of this survey. The Court of Appeals noted this clear direction when it ruled that the BLM could proceed with an internal staff inventory prior to any public hearings held as part of a section 202 planning process.

The results of the study and a summary of additional lands selected during this process is available at <http://www.blm.gov/ut/st/en/prog/blm_special_areas/utah_wilderness.html >.

State-Owned Lands

State-owned lands are regulated by the individual states of Arizona, Colorado, Utah, and Wyoming. Oil-producing province lands in Arizona are all within the Navajo Indian Reservation, thus no Arizona state-owned lands are involved in this analysis. Each state has its own leasing and development regulations that generally follow the federal guidelines. Links are provided to state-owned land administrators for Arizona, Colorado, Utah, and Wyoming.

Colorado state-owned lands: Colorado state lands are referred to as State Trust Lands and are administered by the Colorado State Land Board. The Colorado State Land Board Web site is

<http://trustlands.state.co.us>. The Land Board is governed by a five-member commission appointed by the Governor and approved by the state Senate. The Web site contains all of the rules and regulations pertaining to oil and gas leasing. The Land Board has monthly meetings and the schedule is posted on its Web site. Lands in Mesa and Montrose Counties are managed by the Northwest District office in Craig, and lands in San Miguel, Dolores, and Montezuma Counties are managed by the South District office in Alamosa. District boundary maps and contact information are listed for each District at the following Web site - <http://www.lands.state.co.us/Personnel/Districts.asp>.

Oil and gas development in Colorado is regulated by the Colorado Oil and Gas Conservation Commission. The Commission's Web site contains all of the rules and regulations for oil and gas development as well as production and well-log data. Personnel listings and phone numbers are available on the Web site.

Wyoming state-owned lands: State-owned lands in Wyoming are administered by the Wyoming Office of State Lands and Investments, <http://slf-web.state.wy.us>. The State of Wyoming owns approximately 3.6 million surfaces acres (1.5 million ha) and 4.2 million mineral acres (1.7 million ha). Approximately 86% of the surface acres and 84% of the mineral acres are managed for the benefit of the public schools. In addition, there are approximately 9000 acres (3640 ha) of non-trust acquired land within the state allocated to various state agencies that benefit specific institutions and the public. The Office of State Lands and Investments is governed by an elected five-member Board of Land Commissioners. The Web site has links to all of the rules and regulations pertaining to the leasing of mineral rights, and a listing of personnel and contact information.

Drilling and production of oil and gas is regulated by the Wyoming Oil and Gas Conservation Commission (WYOGCC), <http://wogcc.state.wy.us>. The Web site contains a substantial amount of information pertaining to Wyoming's oil and gas resources. In addition to regulatory and statistical data, the Web site provides geological and geophysical log data and a multi-layered mapping function that is designed to map well locations, federal lease ownership and federal unit boundaries, as well as several other parameters.

Utah state-owned lands: State-owned lands in Utah are divided into two groups. In general, the Utah School and Institutional Trust Lands Administration (SITLA) manages lands that were deeded to the state at the time of statehood for the benefit of schools and education. Lands that were subsequently deemed state-owned or Sovereign after statehood are those lands associated with navigable rivers, waterways, and lands underlying Great Salt Lake. The Utah Division of Forestry, Fire and State Lands (FFSL) manages these Sovereign lands. Each organization has its own rules and regulations, and issues oil and gas leases both on a competitive and non-competitive basis. The majority of state-owned lands in Utah are Trust Lands.

Trust Lands – In general, Trust Lands are those lands that were deeded to the state at the time of Statehood. The following citations were taken from the Utah School and Institutional Trust Lands Administration (SITLA) Web site <http://www.utahtrustlands.com/about> to explain how Trust Lands are managed.

> The Utah School and Institutional Trust Lands Administration was created in 1994 to manage 12 real estate trusts granted to the state of Utah by the United

States at statehood. At that time, 1/9 of the total land in the state was designated school trust land, with added acreage for 11 other beneficiaries. Trust land totaled 7,475,297 acres [3,025,253 ha] at statehood. Since then, about half of what was originally granted to the state has been sold to private owners. More than 30% of what is now private land in Utah was originally trust land. The cash from the sale of those trust lands was deposited into the permanent funds of the beneficiaries.

……

The [SITLA] manages a 3.5 million-acre [1.4 million ha] real estate portfolio for the financial benefit of the 12 beneficiaries.

Trust lands include both surface lands and mineral lands. The 3.5 million acres discussed so far refer to surface lands in the trust. Most of these lands also have subsurface, or mineral lands, with them. In addition, there are about a million more acres [0.4 million ha] of mineral-only lands in the trust - for a total of 4.5 million acres [1.8 million ha] of mineral lands. Even though there are 12 trust beneficiaries, the Common Schools Trust owns 95% of all Utah trust land.

Some areas of the state have large amounts of trust land, while others do not. For example, there are only 32 acres [13 ha] of trust land in Salt Lake County, while Millard County contains almost 403,000 acres [163,000 ha]. Rural areas have a larger number of trust-land acres.

The SITLA address is 675 East 500 South, Ste. 500, Salt Lake City, UT 84102. The Oil and Gas Group, <http://www.utahtrustlands.com/oil_gas/index.html>, manages the oil and gas resources of the lands managed by the trust. The following general overview of oil and gas leasing on SITLA lands was provided by SITLA.

I. How to lease trust lands -

A. Competitive bidding process

1. Lands are nominated by outside parties or selected by SITLA staff.
2. Quarterly sales are held in January, April, July, November.
3. Sealed bid format opened on the last day of the month in which the sale is posted.
4. Winner is highest bidder who is qualified to do business in Utah and submits application on an appropriate form.

B. Non-competitive bidding process

1. Suspended in May 2000 – reinstated in limited form under new oil and gas rules in April 2005.
2. Selected parcels which receive no bids at the sealed bid auction, will be available “over the counter” from 8:00 AM the day after the sale for 90 days.
3. If not leased during that time, the lands must go through a competitive bid sale again.

II. What are the lease terms -

A. Basic terms

1. 1/8 (12.5%) landowner's royalty to SITLA
2. 10 year lease term

B. Terms may be modified at the discretion of the Director

III. Process for acquiring drilling permit -

A. Company puts location on drilling schedule and begins to check on rig availability.

B. Company stakes location and contracts for archeological study.

C. Application for Permit to Drill (APD) is filed with Division of Oil, Gas and Mining (DOGM) and simultaneously with SITLA.

D. Application for Permit to Drill to SITLA must include an Archeological Survey.

E. School and Institutional Trust Lands Administration forwards Archeology Study to State Historic Preservation Office (SHPO) for a 10-day review period.

F. Company verifies that it has adequate bonding for plugging, reclamation, and lease obligations under state guidelines with both DOGM and SITLA.

G. On-site meeting is scheduled by DOGM. Any additional concerns by other state agencies are discussed at this meeting.

H. At the end of the 10-day SHPO review, if there are no concerns, SITLA notifies DOGM that it has released the APD for approval.

I. DOGM proceeds with their approval process.

The SITLA does not consult with the BLM on its lands, but rather works with state agencies such as DOGM and the Division of Wildlife Resources to maintain standards on Trust Lands.

The Oil and Gas Group Web site provides links to Current Competitive Leasing, Over-The-Counter Leasing, Withdrawals and Special Notices, Fee Schedule, Forms and Applications, Rules, and Contacts. Geographic Information System data are available online at <ftp://lands-ftp.state.ut.us/pub/index.htm>. This Web page provides access to downloadable GIS data on BLM and Trust Lands surface and mineral ownership, and links to several federal GIS-based Web sites.

Sovereign Lands – Sovereign lands are those lands that lie below the navigable waters within Utah. There are approximately 1.5 million acres (0.6 million ha) of Sovereign lands in Utah; however, there are only about 5200 acres (2100 ha) within the Paradox Basin province and none have been identified in the other three oil-producing provinces. The following explanation of Sovereign lands is taken from the FFSL Lease Information Web page <http://www.ffsl.utah.gov/sovlands/leases/leaseinfo.php>:

> The state of Utah recognizes and declares that the beds of navigable waters within the state are owned by the state and are among the basic resources of the state, and that there exists, and has existed since statehood, a public trust over and upon the beds of these waters. It is also recognized that the public health, interest, safety, and welfare require that all uses on, beneath or above the beds of navigable lakes and streams of the state be

regulated, so that the protection of navigation, fish and wildlife habitat, aquatic beauty, public recreation, and water quality will be given due consideration and balanced against the navigational or economic necessity or justification for, or benefit to be derived from, any proposed use.

The FFSL conducts competitive oil and gas lease sales and notices are published well in advance of sales. Administrative rules and Lease Application forms are also posted on the FFSL Web page. Map data in GIS format are also available online at <http://www.ffsl.utah.gov/mmgis.php>.

Privately Owned Lands

Privately owned lands are also known as fee lands. Where the mineral estate is owned by one entity or party and the surface is owned by another entity, this is known as a split-estate. These lands can be owned by an individual; a non-government legal entity such as a company, partnership, or corporation; or a sovereignty in the case of an Indian tribe. In any case, oil and gas leases are negotiated with the mineral estate owner(s) and surface access is often negotiated with the surface owner(s). Where an Indian tribe owns the mineral estate, leases are usually negotiated with the tribal business committee. There are numerous royalty owners associations that have been formed to pool information and lease management among groups of individual royalty owners, but none of these operate in Utah.

One of the largest non-profit nationwide organizations is the National Association of Royalty Owners (NARO). The NARO recently formed the Rocky Mountain chapter, <http://rockies.naro-us.org/> to represent the interests of mineral owners in the Rocky Mountain region of the United States. The Web site has a link to a free brochure that contains information on the lease process, negotiations, surface damages, spacing units, force pooling, division orders, and royalties.

Native American Reservation Lands

Native American Reservation or tribal lands include lands within an established Indian Reservation and held in trust by the U.S. government. Where tribal lands are held in trust, the BIA, <http://www.doi.gov/bia/>, in association with the tribe administers the mineral estate. Where tribal lands are owned in fee, the tribe has sole authority for leasing its mineral rights. Also, within some reservations, members of the tribe own land individually; these are referred to as allotted lands. Because of the complexity of Indian land and mineral ownership, only designated reservation lands are shown on the four province maps. We recommended contacting each tribe regarding specific mineral ownership interests within its reservation. The addresses and contact information for the Native American tribes and BIA agencies are listed in Appendix B.

Native American Reservation lands in the Uinta Basin province are within the Uinta & Ouray Indian Reservation, which is headquartered in Fort Duchesne, Utah. The reservation is home to the Ute Indian Tribe. The Ute Indian Tribe's Web site, <http://www.utetribe.com/>, lists the various entities who own or share mineral interests within the reservation and also provides department and personnel contacts.

Native American Reservation lands in the Paradox Basin province in Utah are the Navajo Nation, <http://www.navajo.org/>, lands within the Navajo Indian Reservation. The headquarters for the Navajo Nation is in Window Rock, Arizona. Reservation lands in Colorado are within the Ute Mountain Indian Reservation, home to the Ute Mountain Ute Indian Tribe, <http://www.utemountainute.com/>. The Ute Mountain Ute Tribe is headquartered in Towaoc, Colorado. In addition, there are approximately 8300 acres (3400 ha) of land in the White Mesa area in San Juan County, Utah that are part of the Ute Mountain Indian Reservation.

Native American Reservation lands in the Central Utah thrust belt—Hingeline province are Paiute Indian Reservation lands, home to the Paiute Indian Tribe of Utah. The tribe's new Web site is <http://www.utahpaiutes.org>. There are no Native American Reservation lands in the province.

In the past several years, the BIA has attempted to make the administrative effort more responsive to individual tribal interests. The BIA Office of Indian Energy and Economic Development has published a Notice of Proposed Rulemaking regarding Tribal Energy Resource Agreements (TERAs) designated under Title V, Section 503, of the Energy Policy Act of 2005 in the August 21, 2006, issue of the Federal Register. Tribal Energy Resource Agreements offer federally recognized tribes a new alternative for overseeing and managing energy and mineral resource development on their lands: the authority to enter into energy-related business agreements and leases, and for granting rights-of-way for pipelines, electric transmission, and distribution lines.

The proposed rule is intended to provide a process under which the Secretary of the Interior would grant authority to a tribe through an approved TERA to review and approve leases, business agreements, and rights-of-way for specific energy development activities on tribal lands. Currently, tribes must first seek Secretarial approval of such actions through the BIA. All of the rules and regulations pertaining to oil and gas development on BIA-administered tribal lands are posted on the BIA Web site <http:/www.doi.gov/bia/>.

Utah/Wyoming Thrust Belt Land Classification Summary

Major oil plays in the Utah/Wyoming thrust belt province lie in a 70-mile-long by 18-mile-wide (110 km x 29 km) elongate lobe containing approximately 708,417 acres (286,696 ha) of land in north-central Utah and southwestern Wyoming (figure 12-3, plate 3). The lands are located in parts of Morgan, Rich, and Summit Counties, Utah, and Lincoln and Uinta Counties, Wyoming. Surface and mineral ownership are divided among BLM, private, and state entities. Table 12-2 shows the land classification by major ownership or management entity. The majority of lands in Utah are privately owned (81.4%), although BLM and state-owned lands are dominant in Wyoming. The lands underlying waterways, lakes, and reservoirs are classified as "Water" and are not subdivided by ownership. In Utah, these lands are primarily state-owned and administered by the FFSL. The mineral estate on these lands may or may not be leasable depending on the location.

Bureau of Land Management Lands

Bureau Land Management lands in the Utah/Wyoming thrust belt province encompass 94,797 acres (38,364 ha), including 83,414 acres (33,758 ha) of land in Wyoming and 11,384 acres (4607 ha) of land in Utah. There are no Wilderness Area or Wilderness Study Area lands

in the Utah/Wyoming thrust belt province. However, a minor amount of land (50 acres [20 ha]) has been designated as BOR managed lands. Bureau of Reclamation lands are, presumably, those lands adjacent to or near federally-owned or managed dams, reservoirs, and/or other federal water or water-related projects. This study has not determined whether any BOR lands have been leased or are leasable for oil and gas. Withdrawal orders have not been researched for any public lands identified in play areas in the Utah/Wyoming thrust belt province.

Mineral ownership and lands affected by withdrawal orders are identified on MT plats for each township; these plats can be accessed in BLM SOs in Salt Lake City, Utah, and Cheyenne, Wyoming, and local BLM FOs. Master title plats are also available by county in county courthouses located in each county seat. For the Utah/Wyoming thrust belt province, contact information for Utah and Wyoming BLM SOs and FOs are listed in Appendix F, and county courthouses are listed in Appendix G. The Utah BLM SO is located in Salt Lake City. All of the planning documents, regulations, and maps related to oil and gas can be viewed at the Information Access Center. The BLM Utah SO Web site is <http://www.blm.gov/ut/st/en.html>. Master title plats for Utah can also be viewed digitally through the Access Center Web page <http://www.ut.blm.gov/LandRecords/mtps_his_ut.cfm>. The Salt Lake FO is responsible for planning and management activities for the area within the Utah portion of the thrust belt province. The Salt Lake FO Web site is <http://www.ut.blm.gov/saltlake_fo/>.

The BLM Wyoming SO is located in Cheyenne. The BLM Wyoming SO Web site can be accessed at <http://www.wy.blm.gov/>. The Public Information Center Web page, <http://www.blm.gov/wy/st/en/resources/public_room/mtps.html>, provides digital access to MT plats and Cadastral Survey data for the state. The Kemmerer FO is responsible for the planning and management of lands within the Wyoming portion of the thrust belt province. The Web site for the Kemmerer FO is <http://www.wy.blm.gov/kfo/>.

Privately Owned Lands

There are approximately 577,000 acres (234,000 ha) of privately owned lands in the Utah/Wyoming thrust belt province, including about 384,000 acres (155,000 ha) in Utah, and about 192,000 acres (77,700 ha) in Wyoming. An examination of MT plats is necessary to determine which lands are owned in fee and which have split-mineral estate. Master title plats are available online for Wyoming and Utah, all BLM SOs, and at local county courthouses. Lease terms, royalty rates, and surface access are negotiated with each surface and or mineral owner as required. An introduction to oil and gas leasing and other information is provided on the NARO Web site. The mission of NARO, taken from their Website, is "…to encourage and promote exploration and production of minerals in the United States while preserving, protecting, advancing and representing the interests and rights of mineral and royalty owners through education, advocacy and assistance to our members, to NARO chapter organizations, to government bodies and to the public."

State Lands, Parks, and Wildlife Reserves

There are approximately 23,000 acres (9300 ha) of state-owned lands in the Utah/Wyoming thrust belt province, including 20,457 acres (8279 ha) in Wyoming, and 2541 acres (1028 ha) in Utah. In addition, there are 10,210 acres (4132 ha) of Utah state lands that are within state parks and wildlife reserves. Utah state-owned lands within state parks are managed

by the Division of State Parks and Recreation; lands within state wildlife reserves are managed by the Division of Wildlife Resources. State-owned lands in Wyoming are administered by the Wyoming Office of State Lands and Investments. Please refer to the contacts provided for each Web site for mineral leasing policies, rules, and regulations.

Central Utah Thrust Belt – Hingeline Land Classification Summary

There is only one play in the central Utah thrust belt – Hingeline province: the Navajo Sandstone play. The province covers approximately 1.19 million acres (482,000 ha) (figure 12-4, table 12-3, and plate 4), all of which are in Utah.

Bureau of Land Management Lands

Bureau of Land Management lands in the central Utah thrust belt – Hingeline province include 117,271 acres (47,460 ha) of unrestricted lands and 82,985 acres (33,584 ha) of restricted or withdrawn lands. These restricted or withdrawn lands may be open to oil and gas leasing. Contact the BLM SO or local FO for specific withdrawal orders. Bureau of Land Management lands in most of the province (Piute, Sanpete, and Sevier Counties), including the newly discovered Covenant field, are managed by the Richfield FO, < http://www.blm.gov/ut/st/en/fo/richfield.html >. Public lands in Utah County are managed by the Salt Lake FO, <http://www.ut.blm.gov/saltlake_fo/>, and public lands in Juab and Millard Counties are managed by the Fillmore FO, <http://www.ut.blm.gov/fillmore_fo/>. A relatively small part of the province in Beaver County is managed by the Cedar City FO, <http://www.ut.blm.gov/cedarcity_fo/>. The addresses for the BLM FOs are listed in Appendix F. A discussion of planning activity within each FO is discussed earlier in this summary.

U.S. Forest Service Lands

There are more than 300,000 acres (121,000 ha) of FS-classified lands in the central Utah thrust belt – Hingeline province that are part of the National Forest System. These lands lie primarily within the Fish Lake, Manti-LaSal, and Uinta National Forests. Links to the Web sites for these FS offices are: Fishlake, Manti-LaSal, and Uinta National Forests. Links to the USFS Web site and subsequent links to the policies, regulations, and rules pertaining to oil and gas drilling and development have been presented in a previous section of this summary.

Native American Reservation Lands

There are 544 acres (220 ha) in the central Utah thrust belt – Hingeline province that are classified as Native American Reservation lands**.** These lands belong to the Paiute Indian Tribe of Utah and are located near the town of Joseph. The Paiute tribe contact information is provided in Appendix B. The tribe's Web site is <http://www.utahpaiutes.org>.

Privately Owned Lands

Nearly one-half of the central Utah thrust belt – Hingeline province is classified as privately owned lands. This includes 512,206 acres (207,290 ha) of unrestricted lands, 21,359

acres (8644 ha) of lands within the National Forest system, and 20,830 acres (8430 ha) of lands that are subject to protective withdrawal. Lands that are subject to protective withdrawal may or may not be leasable, and an examination of the MT plats is required to determine the nature of the protective withdrawal order.

State Lands

There are 130,821 acres (52,943 ha) of state-owned lands in the central Utah thrust belt–Hingeline province including 57,514 acres (23,276 ha) of SITLA-managed lands, 48 acres (19 ha) within State Parks, 28,000 acres (11,300 ha) in State Wildlife Reserves, and 1136 acres (460 ha) that are subject to protective withdrawal orders. A discussion on SITLA lands and contact information for Utah State Parks and Wildlife Reserves have been presented earlier in this summary.

Uinta Basin Land Classification Summary

The Uinta Basin province is primarily located in northeastern Utah, although a minor part of the basin overlaps into northwestern Colorado (figure 12-5, table 12-4, and plate 5). The province covers approximately 5.39 million acres (2.18 million ha); 5.26 million acres (2.13 million ha) (97.6%) are in Utah, and 0.129 million acres (0.052 million ha) (2.4%) are in Colorado.

Bureau of Land Management Lands

Bureau of Land Management lands include the following subgroups: non-classified lands in Utah (1,210,121 acres [489,736 ha]), non-classified lands in Colorado (100,596 acres [40,711 ha]), acquired lands (4263 acres [1725 ha]), BOR lands (7203 acres [2915 ha]), DOD lands (2718 acres [1100 ha]), Power Withdrawal and classified lands (35,776 acres [14,479 ha]), Protective Withdrawal lands (663,239 acres [268,413 ha]), and Public Water Reserve lands (2446 acres [990 ha]). For the most part, non-classified lands are open for oil and gas leasing with standard lease terms. Bureau of Reclamation lands, DOD lands, and Power Withdrawal lands are likely withdrawn from mineral entry. Acquired lands and Protective Withdrawal lands may be available for oil and gas development if the withdrawal order is for other minerals. An examination of the MT plats will provide clarification for lands that are subject to withdrawal orders. The plats are available at each BLM SO and FO (Appendix F), and at each county courthouse (Appendix G). Master Title plats for Utah are available online at the Access Information Center. Master Title plats for Colorado are not available online, but should be in the near future.

There are eight WSAs and one Instant Study Area (ISA) in the Uinta Basin oil province containing 387,119 acres (156,665 ha) that the Utah BLM has identified as having Wilderness potential. Under the current RMP, the only lands not open to leasing are those identified as WSAs. Under the proposed RMP, four alternatives are being evaluated, each of which include no leasing of current WSAs. Wilderness Study Areas and ISAs are identified on plate 2, and labeled on each plate where they occur. A summary of these areas is included in Appendix E. Additional information on WSAs and ISAs can be found on links to the BLM's Utah Wilderness Web page <http://www.blm.gov/ut/st/en/prog/blm_special_areas/utah_wilderness.html>.

U.S. Forest Service Lands

There are 482,576 acres (195,299 ha) of mostly BLM lands whose surface is managed by the FS. These lands are within the National Forest system and are subject to oil and gas leasing generally with surface occupancy stipulations. These stipulations are usually outlined in the RMP, LUP, or other planning documents. For specific locations, it may be necessary to contact the local BLM FO or FS district office. Forest Service district office locations and contact information can be found on each National Forest Web site.

Forest Service lands in Duchesne and Uintah Counties lie within the Ashley National Forest, and FS lands in Utah and Wasatch Counties lie within the Uinta National Forest. Rules and regulations for oil and gas drilling and development on National Forest lands are outlined on the FS Minerals and Geology Management Web page - <http://www.fs.fed.us/geology/>. The Web page contains a link to a Web page for Energy Leasable Minerals, <http://www.fs.fed.us/geology/mgm_leasable.html> , which, in turn, provides links to all of the federal legislation (Acts), policies, regulations, planning manuals, and forms related to oil and gas development on FS lands. The FS Web site <http://www.fs.fed.us/> provides links to all of the regional offices within the FS system and contains all of the legislation, policies, regulations, and rules pertaining to surface use and mineral development on FS lands.

Native American Reservation Lands

Native American Lands in the Uinta Basin generally lie within the Uintah & Ouray Reservation and consist of several different types of ownership. The following explanation of surface and mineral ownership and contact information for the staff of the below-listed agencies and organizations is provided in a document titled *How to do Business on the Uintah and Ouray Reservation*. The document is available on the Ute Indian Tribe's Energy and Minerals Department Web page, <http://www.utetribe.com/mineralResourcesDevelopment/energyMinerals.html>.

> The Uintah & Ouray Reservation in the Uinta Basin province has a checkerboard (ownership) reservation containing Ute Indian Tribe, Ute Indian Allotted and Ute Indian Tribe and Ute Distribution Corporation jointly managed Indian trust minerals, and with Fee (privately owned) and federal minerals. Indian properties cover approximately 1.2 million surfaced-owned acres [0.49 million ha] and 400,000 mineral-owned acres [162,000 ha] within the 4-million-acre [1.6 million ha] jurisdictional boundary. Both surface and mineral properties are owned by the Ute Indian Allottees, Ute Indian Tribe, and the Ute Indian Tribe and Ute Distribution Corporation in joint management.

The Ute Indian Tribe has formed its own energy development company, Ute Energy, LLC. The following introduction was taken from the Ute Energy, LLC Web site.

> The Ute Indian Tribe as part of its financial plan has formed an integrated energy company (Ute Energy LLC), with plans to develop 300,000 acres [121,000 ha] of undeveloped lands on the Uintah & Ouray reservation. Four distinct areas are in

the process of development with partnerships already in place with Salt Lake City based Questar Corp.; Boston based Fidelity Investors Management; Denver based Bill Barrett Corp.; and Berry Petroleum of Bakersfield, California.

The addresses and telephone numbers, and Web sites, if available, for the Ute Indian Tribe, Ute Energy, LLC, BIA Uintah & Ouray Agency, and Ute Distribution Corp. are provided in Appendix B.

Privately Owned Lands

There are 1.2 million acres (486,000 ha) of privately owned lands in the Uinta Basin province including approximately 28,000 acres (11,000 ha) in Colorado. Some of these lands have split-mineral estates where the surface may be privately owned and the mineral rights have been reserved by the federal government. An examination of MT plats will show where and what mineral rights have been reserved.

State Lands

There are 591,718 acres (239,468 ha) of state-owned lands in the Uinta Basin province. These lands primarily include SITLA lands and lands that are within State Wildlife Reserves and State Parks. Contacts for these agencies have been provided in previous sections of this report. The SITLA Web site, <http://www.utahtrustlands.com>, provides links to downloadable GIS files that provide surface and mineral ownership coverage countywide and statewide, and oil and gas leasing rules, regulations, and a schedule for competitive lease offerings.

U.S. Fish and Wildlife Reserve Lands

There are about 8975 acres (3632 ha) of land within the Ouray Wildlife Refuge of the Uinta Basin province. Some or all of these lands may be withdrawn from mineral entry or surface occupancy. An examination of MT plats will show which lands have been withdrawn. The Vernal FO has identified lands that have restricted surface occupancy.

Paradox Basin Land Classification Summary

The Paradox Basin province is located primarily in southeastern Utah and southwestern Colorado with a small amount of land in northeastern Arizona. The Paradox Basin province is the largest of the four oil-producing provinces by area (7.78 million acres [3.15 million ha]), and includes 6.18 million acres (2.50 million ha) in Utah, 1.48 million acres (0.60 million ha) in Colorado, and about 121,000 acres (490,000 ha) in Arizona (figure 12-6, table 12-5, and plate 6). The province was also one of the first areas to be explored for oil in Utah.

Bureau of Land Management Lands

There are approximately 4.1 million acres (1.7 million ha) of BLM managed lands in the Paradox Basin province, including 812,539 acres (328,835 ha) in Colorado, and 3,434,458 acres (1,389,925 ha) in Utah. Approximately 282,066 acres (114,152 ha) are subject to protective

withdrawal orders and include lands in Primitive Areas, and Public Water Reserves, or lands under the control of the BOR. Appendix F contains a listing of BLM FO addresses and Web sites for the Paradox Basin province; Appendix G contains a listing of the county courthouses within the play area.

U.S. Forest Service Lands

There are approximately 479,966 acres (194,242 ha) of FS lands in the Paradox Basin province, including 16,208 acres (6559 ha) in Colorado and 460,758 acres (186,469 ha) in Utah. Approximately 6970 acres (2820 ha) are subject to protective withdrawal. All of the FS lands in Utah are in the Manti-La Sal NF, <http://www.fs.fed.us/r4/mantilasal/>. Forest Service lands in Colorado are in the San Juan NF, <http://www.fs.fed.us/r2/sanjuan/>. Links to the FS Web site and subsequent links to the policies, regulations, and rules pertaining to oil and gas drilling and development have been presented in a previous section of this report. Contact information for National Forest lands within this province is included in Appendix C.

Military Reservation Lands

Approximately 1630 acres (660 ha) in the Paradox Basin province are classified as Military Reservation lands. These lands are located near Green River, Utah, and are associated with the former Utah Launch Complex White Sands Missile Range facility. This facility is inactive and lands may or may not be available for mineral leasing.

National Parks, Monuments, and Recreation Areas

The Paradox Basin province has about 828,271 acres (335,197 ha) classified as National Parks, Monuments, and Recreation Areas including 231 acres (94 ha) in Hovenweep National Monument in Utah and Colorado, 150,381 acres (60,858 ha) in Canyons of the Ancients National Monument in Colorado, and 677,659 acres (274,249 ha) in Arches National Park, Canyonlands National Park, Natural Bridges National Monument, and Glen Canyon National Recreation Area (NRA) in Utah. Contact information for all National Parks, Monuments, and Recreation Areas is included in Appendix H. It is likely that most, if not all, of these lands are restricted for mineral entry. However, all valid and existing oil and gas leases at the time of designation of each park, monument, or recreation area are recognized.

Native American Reservation Lands

The Paradox Basin province contains 675,011 acres (273,177 ha) classified as Native American Reservation lands. The majority of these are Navajo Nation tribal lands that lie within the Navajo Indian Reservation, and include Native American Reservation lands in Utah and Arizona. The Navajo Nation administration center is in Window Rock, Arizona. Native American Reservation lands in Colorado are within the Ute Mountain Ute Indian Reservation. Ute Mountain Ute tribal offices are a few miles south of Cortez in Towaoc, Colorado. In addition, the Navajo Nation and the Ute Mountain Ute Tribe may own fee land within the play area that is available for mineral leasing. Contact information for each tribe is included in Appendix B.

Privately Owned Lands

There are approximately 1.15 million acres (0.47 million ha) of privately owned lands in the Paradox Basin province, including 643,788 acres (260,541 ha) in Colorado, and 502,546 acres (203,380 ha) in Utah. Privately owned lands include those lands owned by corporate or individual entities, organizations, and sovereign nations in the case of lands owned by Indian tribes. Some of these lands have split-mineral estate and some privately owned lands lie within the NF system. An examination of MT plats is required to determine which lands are owned in fee. The disposition of fee lands within the NF system can be ascertained by contacting the local FS office.

State Trust and Sovereign Lands

There are about 488,502 acres (197,697 ha) of Utah and Colorado state-owned lands in the Paradox Basin province, including about 5195 acres (2102 ha) of Sovereign lands in Utah. Some of the lands are in State Parks, Recreation Areas, or Wildlife Reserves, and some are subject to protective withdrawal. The Colorado State Land Board manages the trust lands in Colorado, and SITLA manages the trust lands in Utah. The Utah Division of Forestry, Fire, & State Lands manages sovereign lands in Utah. Office addresses and a discussion of each agency have been provided earlier in this summary.

Wilderness Area and Wilderness Study Area Lands

The Dark Canyon Wilderness Area is the only WA in the Paradox Basin province and encompasses about 45,956 acres (18,598 ha) within the Manti-La Sal National Forest between Cathedral Butte and Natural Bridges National Monument. There are 26 WSAs and two ISAs in Paradox province containing 703,305 acres (284,624 ha). There are no WSAs in the Colorado or Arizona parts of the province. A summary of these areas is included in Appendix E. Additional information on WSAs and ISAs can be found on links to the BLM's Utah Wilderness Web page <http://www.blm.gov/ut/st/en/prog/blm_special_areas/utah_wilderness.html>.

Congressionally designated or "official" WSAs are precluded from leasing. Instant Study Areas and other lands that have subsequently been determined to have wilderness characteristics may or may not be leasable depending on the alternative selected in the final RMP.

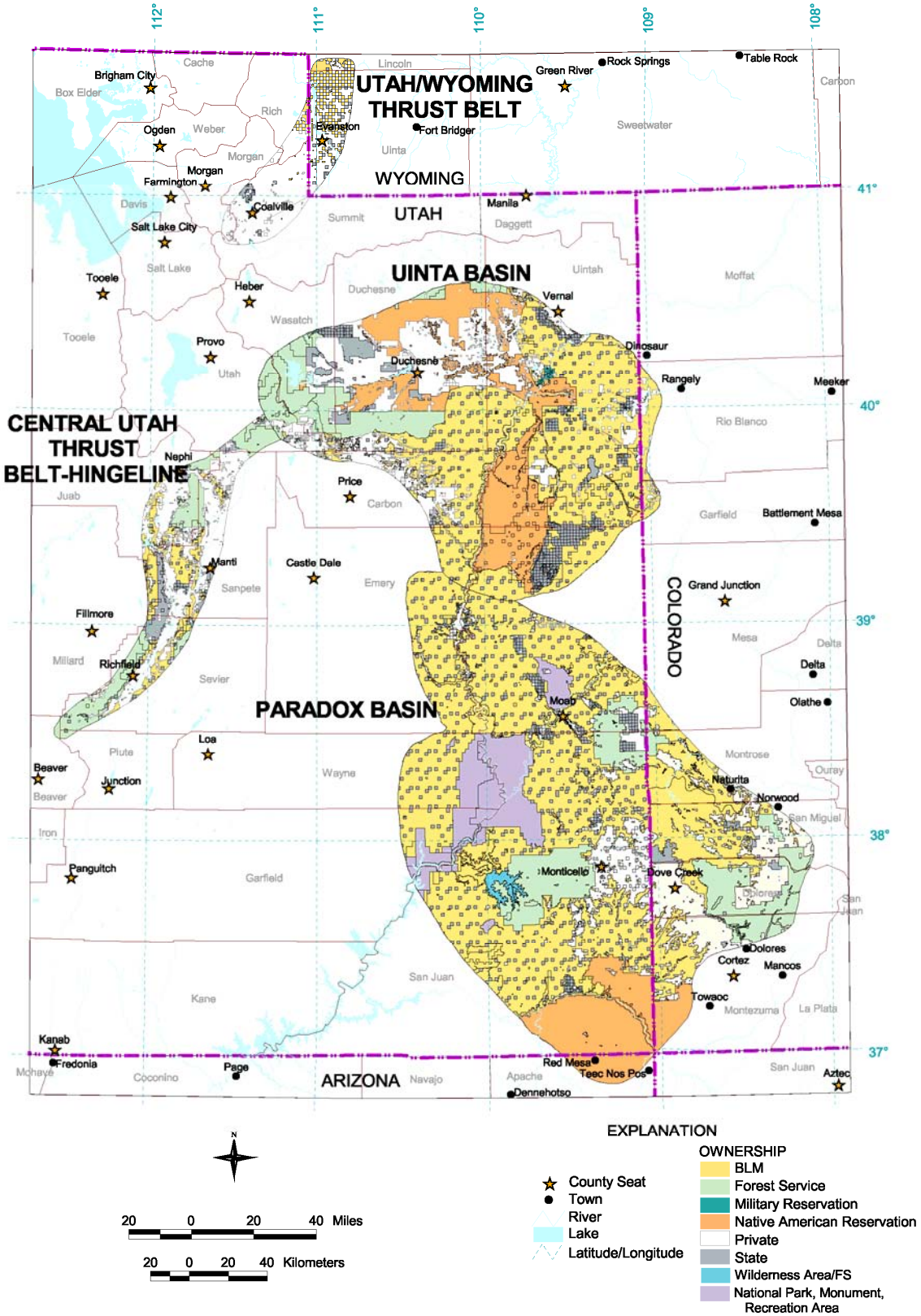


Figure 12-1. Generalized surface and/or mineral ownership map for the major oil-producing provinces of Utah and vicinity as of May, 2007.

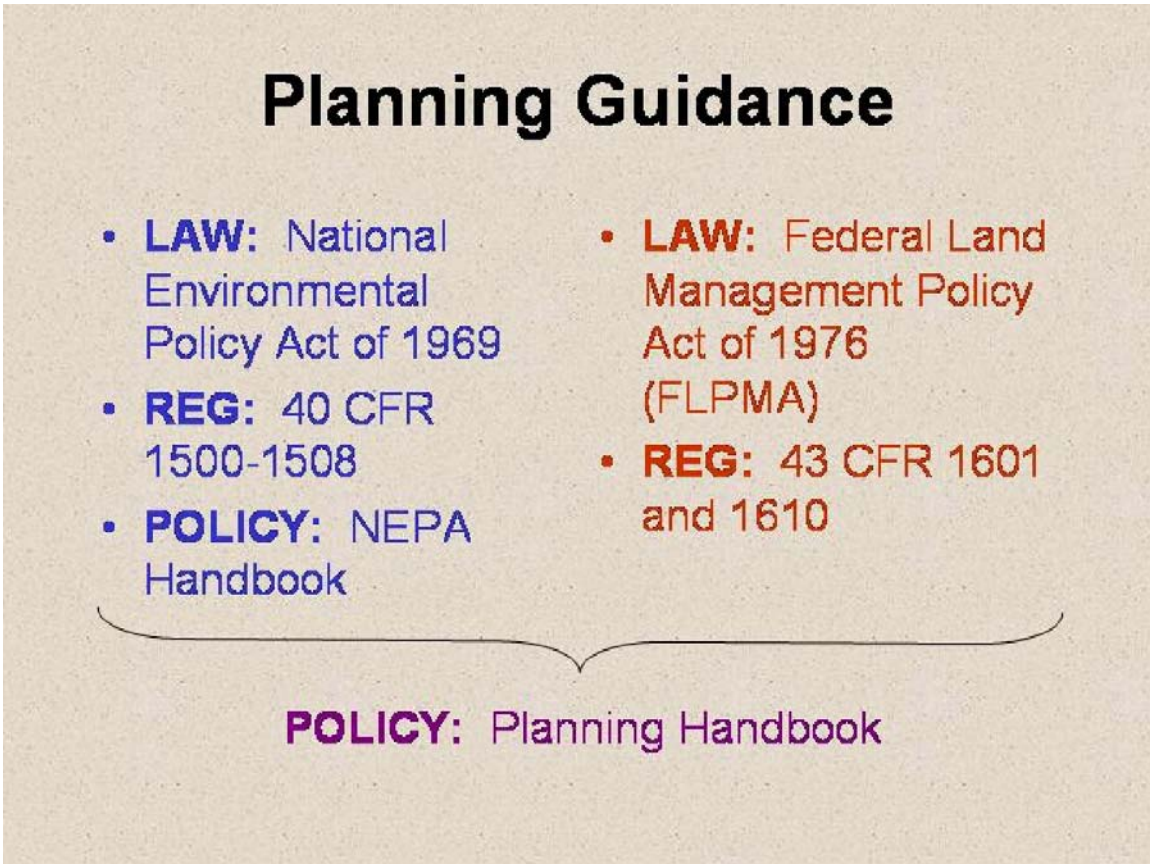


Figure 12-2. Chart depicting Bureau of Land Management's planning framework encompassing NEPA and FLPMA laws, regulations, and policy. Figure obtained from document on Planning Guidance under the Policy section of BLM's Land Use Planning Web site at <http://www.blm.gov/wo/st/en/prog/planning/planning_policy.html>.

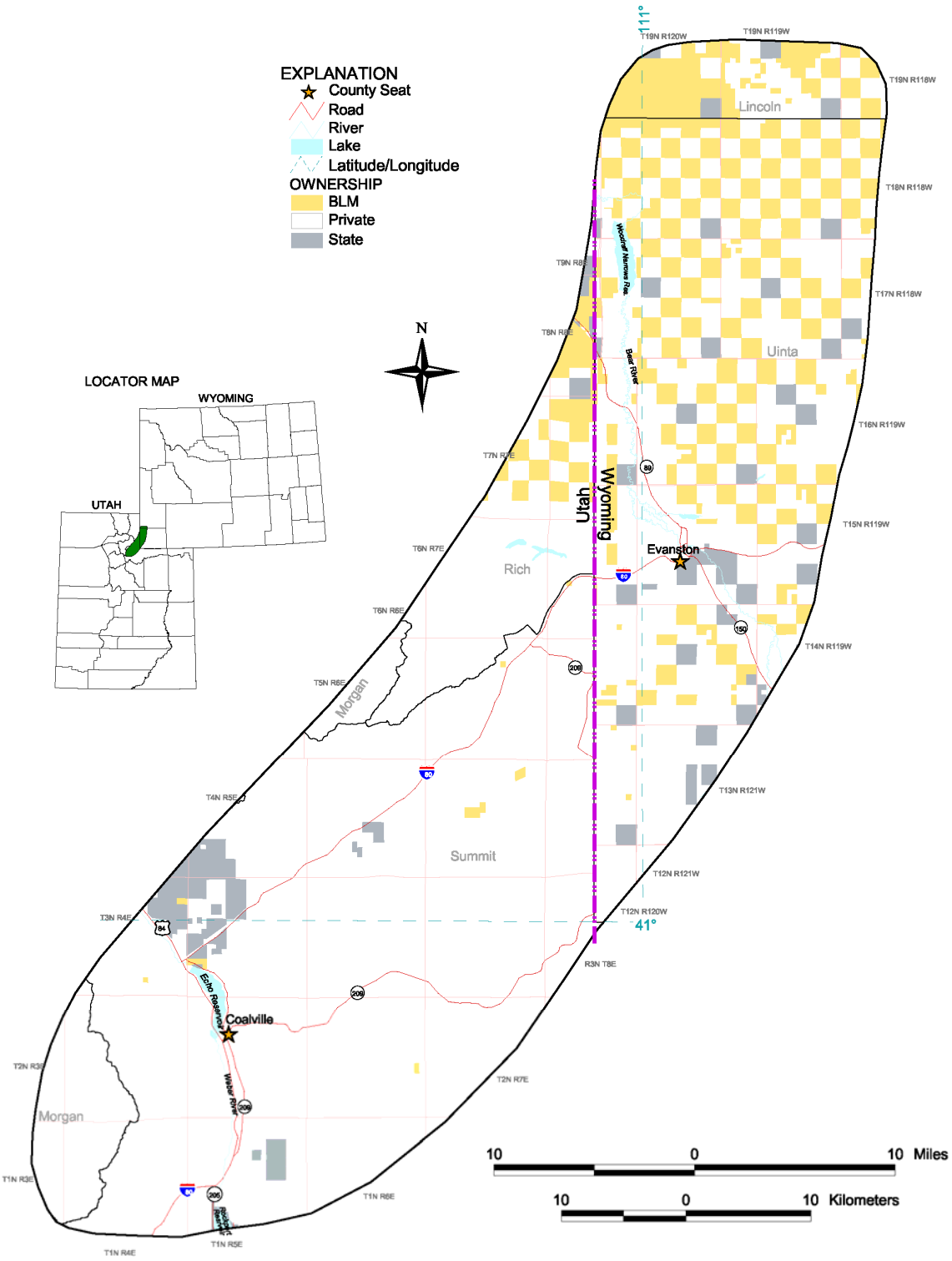


Figure 12-3. Surface and/or mineral ownership map for the Utah/Wyoming thrust belt oil-producing province as of May, 2007.

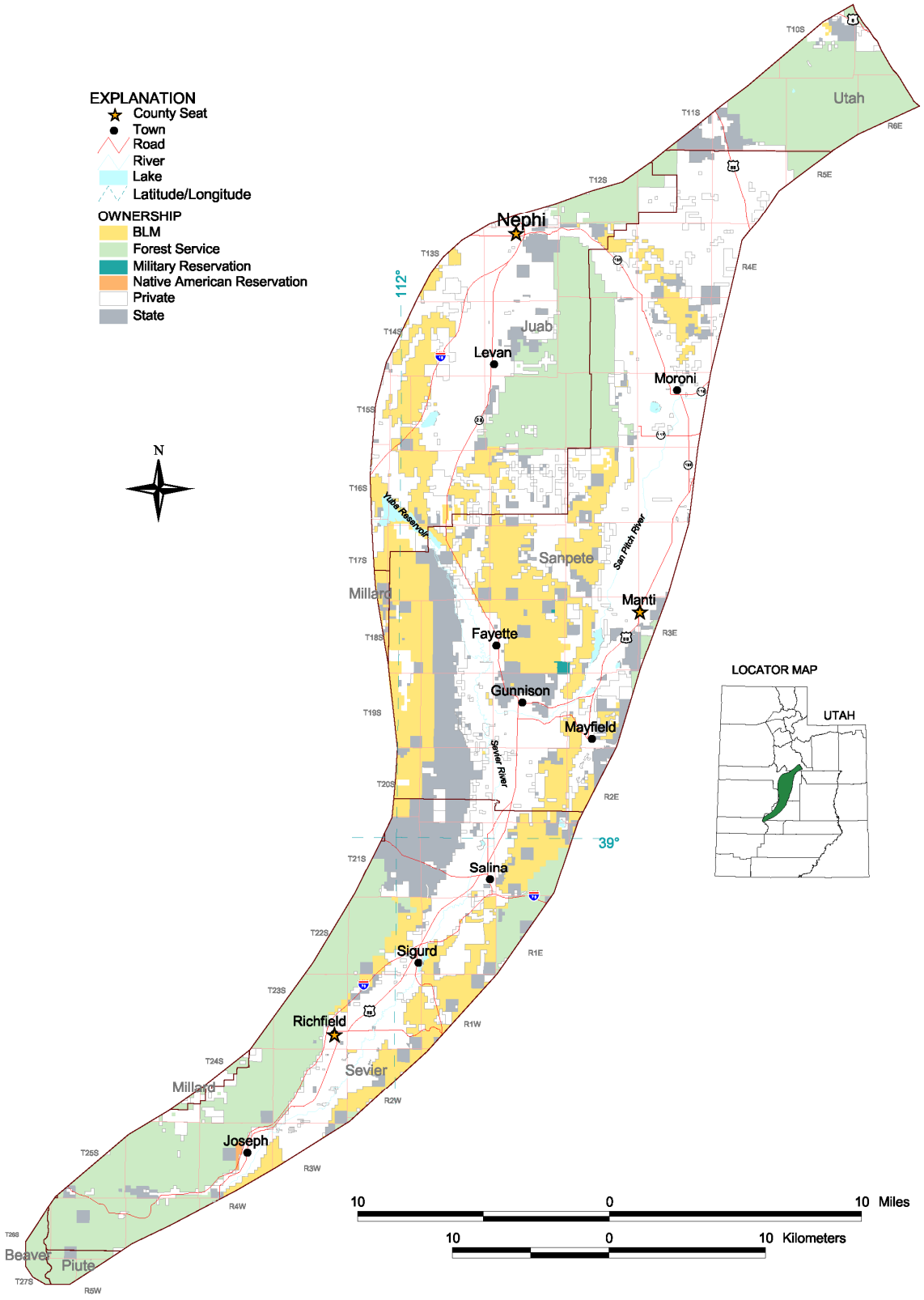


Figure 12-4. Surface and/or mineral ownership map for the central Utah thrust belt – Hingeline oil-producing province as of May, 2007.

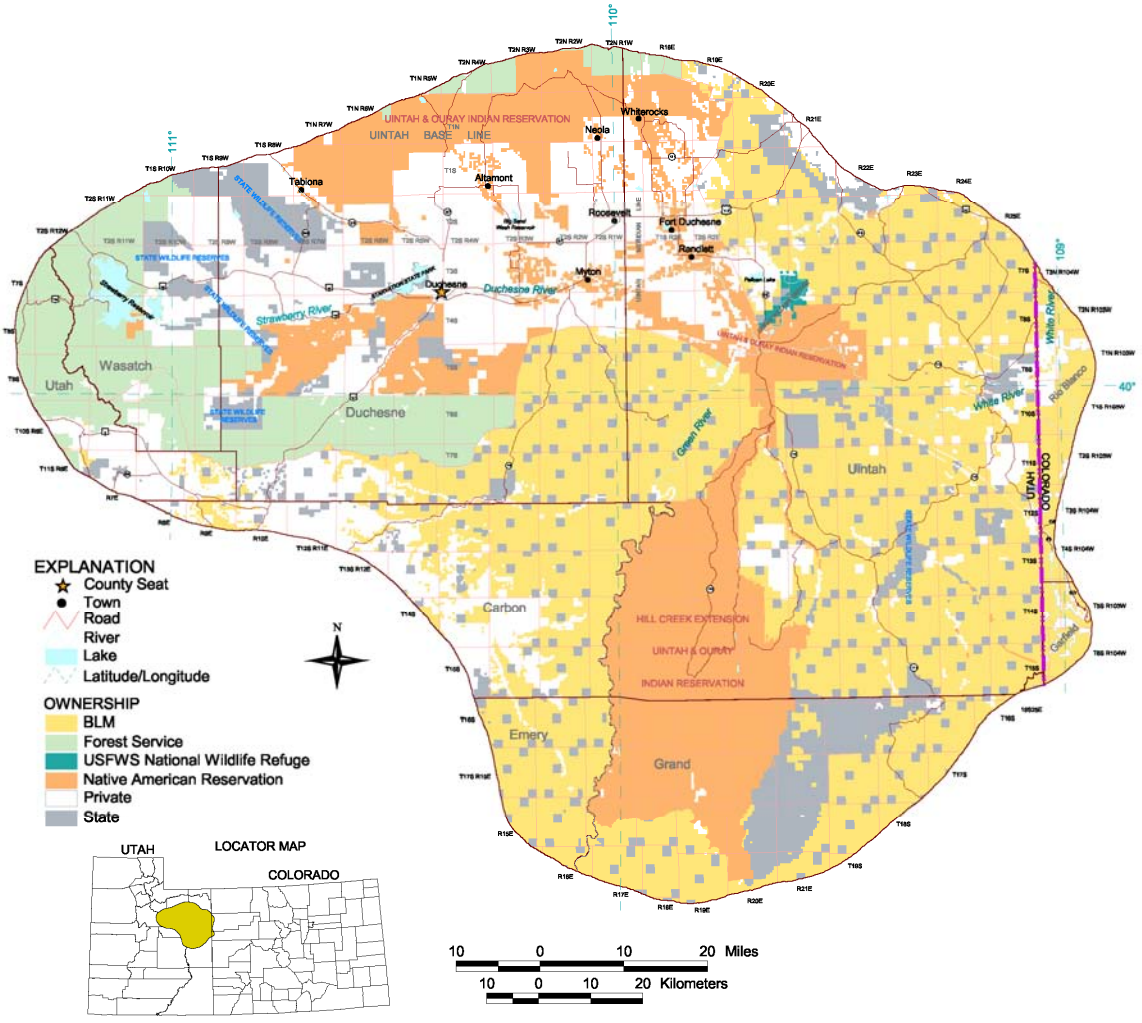


Figure 12-5. Surface and/or mineral ownership map for the Uinta Basin oil-producing province as of May, 2007.

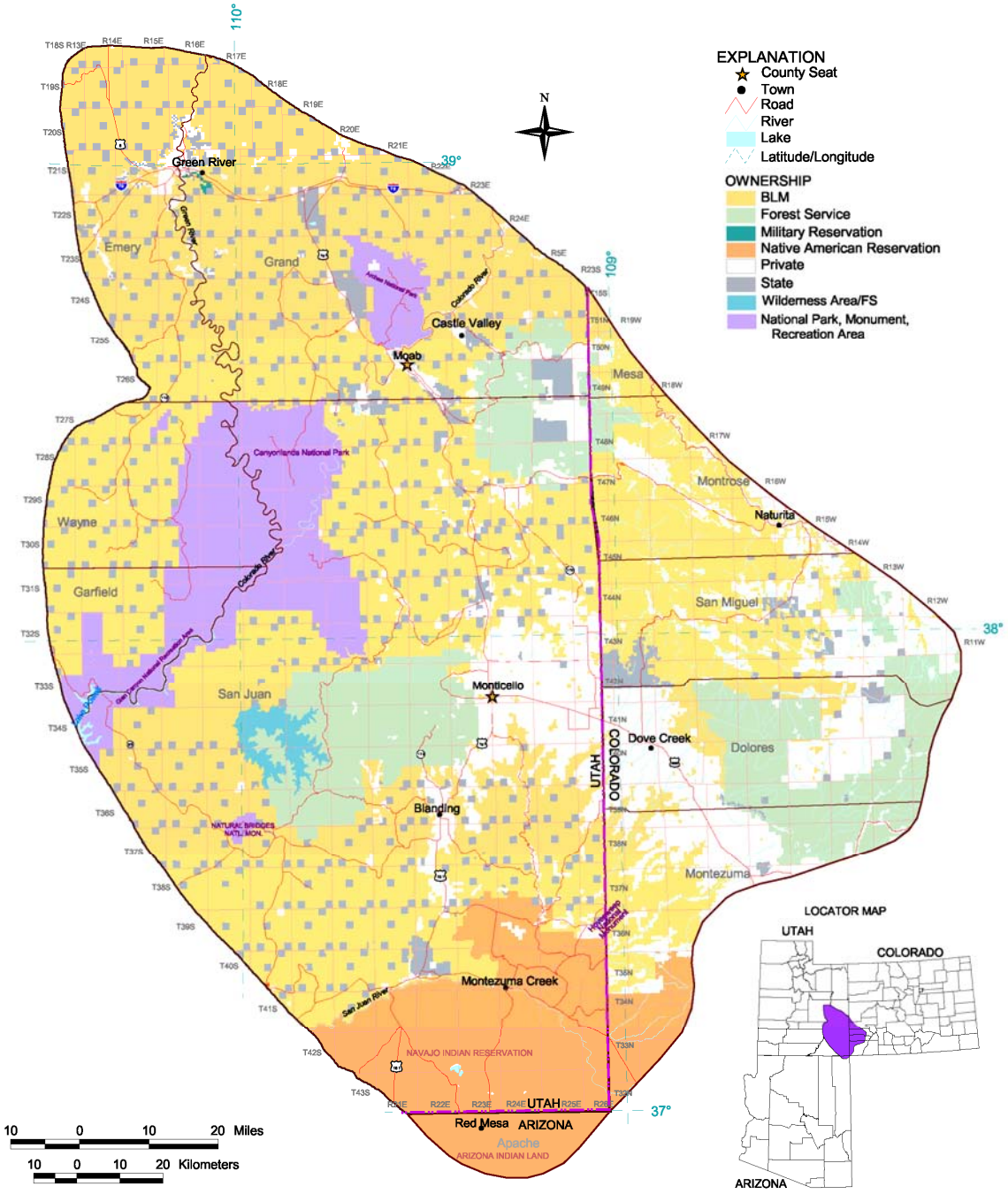


Figure 12-6. Surface and/or mineral ownership map for the Paradox Basin oil-producing province as of May, 2007.

Table 12-1. Land classification and acreage summary for the four oil-producing provinces combined as of May, 2007.

Land Classification	Mineral Mgt. Agency	Acres	Percent of total
BLM	State/District office	6,418,032	42.6
Forest Service	State/District office	1,264,029	8.4
Military Reservations	Department of Defense	1631	< 0.1
National Parks/Monuments/Recreation Areas	National Park Service/ BLM	828,963	5.5
National Wildlife Refuge	U.S. Fish & Wildlife	8975	0.1
Native American Reservations	BIA/Indian Tribe	1,733,795	11.5
Private	Individual/Corporate/ Sovereign	3,477,769	23.1
State Lands	State	1,249,455	8.2
Wilderness Area	Federal	45,956	0.3
Water	State/Federal	41,843	0.3
Total		15,070,488	100.0

Table 12-2. Utah/Wyoming thrust belt land classification summary as of May, 2007.

Land Classification	Mineral Mgt. Agency	Acres	Percent of Play Area
BLM	State/District office	94,797	13.4
Private	Private/Corporate	576,701	81.4
State Lands	State	23,009	3.3
State Parks/Wildlife Reserves	State	10,210	1.4
Water	State/Federal	3702	0.5
Total		708,419	100.00

Table 12-3. Central Utah thrust belt – Hingeline land classification summary as of May, 2007.

Land Classification	Mineral Mgt. Agency	Acres	Percent of Play Area
BLM	State/District office	200,256	16.8
Forest Service	State/District office	301,487	25.3
Military Reservations	Department of Defense	692	<0.1
Native American Reservations	BIA/Indian Tribe	544	<0.1
Private	Individual/Corporate	554,396	46.5
State Lands	State	130,821	11.0
Water	State/Federal	4812	0.4
Total		1,193,008	100.0

Table 12-4. Uinta Basin land classification summary as of May, 2007.

Land Classification	Mineral Mgt. Agency	Acres	Percent of Play Area
BLM	State/District office	2,026,363	37.6
Forest Service	State/District office	482,576	8.9
Native American Reservations	BIA/Indian Tribe	1,058,240	19.6
Private	Private/Corporate	1,200,348	22.3
State Lands	State	591,718	11.0
USFWS (U.S. Wildlife Refuge)	USFWS	8975	0.2
Water	State/Federal	23,874	0.4
Total		5,392,094	100.00

Table 12-5. Paradox Basin land classification summary as of May, 2007.

Land Classification	Mineral Mgt. Agency	Acres	Percent of Play Area
BLM	State/District office	4,096,616	52.7
Forest Service	State/District office	479,966	6.2
Military Reservations	Department of Defense	1631	<0.1
National Parks/Monuments/Recreation Areas	National Park Service/ BLM	828,271	10.6
Native American Reservations	BIA/Indian Tribe	675,011	8.7
Private	Individual/Corporate	1,146,324	14.7
State/Sovereign Lands	State	493,697	6.3
Wilderness Area	Federal	45,956	0.6
Water	State/Federal	9806	0.1
Total		7,777,278	100.0

BEST PRACTICES

CHAPTER 13 – BEST PRACTICES FOR THE JURASSIC NUGGET/NAVAJO SANDSTONE AND TWIN CREEK LIMESTONE THRUST BELT PLAYS, UTAH AND WYOMING

by
Thomas C. Chidsey, Jr., and Craig D. Morgan,
Utah Geological Survey

Introduction

Twelve fields have been discovered in the thrust belt of Utah and Wyoming (figure 1-3), with production from over 80 wells. Data were collected from the files of the Utah DOGM, and the WYOGCC, where there is a wealth of publicly available information, and various publications for selected fields in the Utah and Wyoming thrust belt. This information includes structure maps and cross sections, production and pressure data, completion reports, drilling and development plans, and testimony given at spacing hearings and other hearings before the Utah DOGM and the WYOGCC. The purpose of this data collection is to help determine the best drilling, completion, and secondary/tertiary recovery techniques for these and similar fields in the thrust belt. Specific completion and reservoir management practices were described by various operators of oil fields in the thrust belt.

The principal oil-producing reservoirs for thrust belt fields are the Jurassic Nugget/Navajo Sandstone and Twin Creek Limestone. Three significant practices were employed in the later development of fields in the northern Utah and southwestern Wyoming salient of the thrust belt to enhance the ultimate recovery of oil: (1) horizontal drilling, (2) miscible nitrogen injection, and (3) pressure maintenance for retrograde condensate production.

Horizontal Drilling

General Principles

Horizontal drilling, developed primarily in the 1990s, is now a common, economical technique to increase oil production and reserves. Advances in downhole motors, flexible drill pipe, and measurement-while-drilling technology (MWD) have resulted in improved success and reduced drilling costs. Drilling horizontally (1) improves well/reservoir productivity, (2) increases well drainage area and reservoir exposure, particularly critical if the reservoir is fractured or thin (figure 13-1A, B, and C), (3) delays interface breakthrough (coning) (figure 13-1D), (4) improves sweep efficiency/ultimate recovery, (5) accelerates well payoff and rate of return, (6) reduces inertial (turbulence) pressure losses, (7) accesses remote and isolated zones, (8) improves reservoir characterization, and (9) exploits gravity drainage mechanism effectively (Kikani, 1993; Stark, 2003).

During the 1990s, horizontal drilling was proven to be a viable alternative to conventional vertical drilling. Many drilling and logging problems associated with horizontal drilling have been overcome. Successful horizontal drilling programs have been applied to widespread areas in the U.S. and elsewhere including the Austin Chalk play along the Gulf Coast of Texas, the Bakken Shale play in the Williston basin, the Niobrara Chalk play in the D-J basin, and the Lower Cretaceous Mannville Group in the Alberta basin (Fritz and others, 1992; Stark,

2003), and most recently, nearly all shale-gas plays. These plays target reservoirs dominated by fractures.

Horizontal Drilling Techniques

Types of horizontal wells: Horizontal wells may be classified as long reach and short reach or horizontal laterals (figure 13-2). Long-reach wells consist of medium radius (horizontal lengths of up to 3500 feet [1070 m]) and long radius (horizontal lengths up to 7 miles [11 km]). Short-reach wells consist of short radius (horizontal lengths up to 750 feet [230 m]) and ultra-short lengths up to 200 feet [60 m]). The decision for drilling a particular category in thrust belt fields, and elsewhere, is based on the reservoir depth, regulatory requirements for spacing, type of application, and surface location to avoid topographic features (Kikani, 1993).

Long-reach and short-reach horizontal wells each have advantages and disadvantages. Short-reach horizontal drilling provides a more precise vertical placement of horizontal drains than long-reach drilling, is best for small leases, and sometimes is less expensive if drilled from an existing well. Short-reach wells have less risk than long-reach wells because the kickoff point is usually below fluid contacts and there is good isolation between fluid zones. The disadvantages of short-reach wells are the need for customized drilling equipment and usually a short horizontal drain hole with only openhole completion. Short-reach horizontal wells are usually not logged or cored.

The advantages of long-reach horizontal wells include the fact that they use conventional drilling equipment, accommodate normal-size MWD tools, can use downhole motor and steerable systems, cover 7 miles (11 km) of horizontal length, and allow conventional logging, coring, casing, and completion. The disadvantages of long-reach wells are that they are less accurate on depth and cost more than short-reach wells.

Drilling and completion operations: There have been many advances in horizontal drilling technology and cost control over the last 15 years. The use of advanced downhole motors to build the drilling angle and MWD logging equipment allow accurate entry into potential reservoirs. Cost control using new methods and equipment can reduce the cost of drilling horizontally to less than 1.5 times that of drilling a vertical well.

Wells are prepared in two ways. They are either whipstocked (preferred) or sectioned, depending upon casing condition. Logging and production tests in horizontal wells typically use coiled tubing units (CTU) or pipe conveyed logging (PCL). Most horizontal wells are completed open hole, with slotted/pre-perforated liners, or cemented (Kikani, 1993).

Horizontal Drilling in the Utah-Wyoming Thrust Belt

Horizontal drilling in Utah and Wyoming thrust belt fields targeted the heterogeneous Jurassic Twin Creek Limestone and Nugget Sandstone reservoirs. This heterogeneity, created by fracturing (or the lack thereof) and lithologic variations, provides both the reservoir storage capacity and/or seals (barriers) within the traps. The result is potential undrained compartments ideally suited for horizontal drilling. Oil recovery over a 10-year production span for horizontal wells may be twice that of vertical wells (Lance Cook, Union Pacific Resources Company, verbal communication, 1997). Outcrop analogs, borehole studies and Formation MicroImager

(FMI) or other fracture-identification geophysical well logs are used to plan horizontal drilling programs.

Lithologic variations: The lower third of the Nugget Sandstone typically has lower porosity and permeability when compared to the highly productive upper portion (figure 3-4). Thus, this lower interval was avoided as a target for conventional vertical wells drilled during the early development of Nugget fields. However, the interval has become a target of horizontal drilling techniques where it is oil saturated. This includes both new horizontal wells and horizontal laterals, economically drilled from existing vertical wells. Because the Nugget was deposited in an eolian environment, the reservoir also displays a great deal of heterogeneity. Interdune, foresets, and avalanche-slope deposits have different directional permeabilities. Dual horizontal laterals were drilled for Nugget from an existing well in Anschutz Ranch East field (figure 3-1) but were uneconomical. However, successful Nugget horizontal wells drilled in Painter Reservoir and Ryckman Creek fields of the Wyoming thrust belt (figure 3-1) have proven the technique can be viable for Nugget reservoirs, and thus, additional potential remains in Utah fields.

The Twin Creek Limestone is composed of a variety of lithologies including micritic to argillaceous limestone, sabkha evaporites, and redbed siltstone and claystone. Tightly cemented oolitic grainstone, dolomitized zones, and thin shaly intervals are also present (Bruce, 1988; Parra and Collier, 2000). Most oil and gas production is from perforated intervals in the Watton Canyon, upper Rich, and Sliderock Members (figure 4-4). Seals for the producing horizons are overlying argillaceous and clastic beds, and non-fractured units within the Twin Creek Limestone. Reservoir heterogeneity within the Watton Canyon itself is created where thin-bedded siltstones create additional barriers or baffles to fluid flow. Successful horizontal programs have been conducted in Twin Creek reservoirs of three Utah thrust belt fields – Pineview, Lodgepole, and Elkhorn Ridge (figure 4-1).

Drilling techniques, drainage, well orientation: The Twin Creek Limestone is overlain by the Jurassic Preuss Sandstone that contains a basal layer of salt varying from a few feet to hundreds of feet thick, particularly near the leading edge of thrust faults where the hydrocarbon traps developed. Best practice avoids making a 500-foot-radius (150-m) turn in the salt, which could cause drill-pipe sticking and later casing collapse, and requires drilling 500 feet (150 m) into the usually non-productive upper Twin Creek before turning horizontal (Hart's Oil and Gas World, 1995).

Horizontal wells are generally drilled perpendicular to the dominant orientation of open fractures (figure 13-3). The depth is controlled to be above and parallel to the low-proved oil or oil/water contacts. These contacts may have moved upward during the production history of the field so determining their exact elevation is a key component in drilling plans. Accurate determination of dip and strike of the complex producing structures is also critical to planning horizontal drilling operations. Sophisticated MWD techniques are applied to steer up and down the structure within the target member or zone. "Sweet spots" as thin as 30 feet (10 m) (in the Watton Canyon Member for example), based on extremely low gamma-ray counts and high resistivity, can also be targeted using MWD techniques.

The smallest area that can be effectively drained by a 2000-foot (600-m) horizontal well in fractured Twin Creek reservoirs is 640 acres (260 ha). Communication with other wells

through fractures and water loss can result if horizontal wells extend beyond 2000 feet (600 m) (Ross Mathews, Union Pacific Resources Company, verbal communication, 1994).

Drilling techniques include new wells and horizontal, often multiple, laterals from existing vertical wells. Multiple laterals are required where two separate, geologically distinct zones are present. For example in the Twin Creek Limestone, the productive Rich (containing water with 15,000 to 25,000 parts per million [ppm] total dissolved solids [TDS]) and Watton Canyon (containing water with 50,000 to 60,000 ppm TDS) Members are separated by the shaley Boundary Ridge Member (figure 4-4). Multiple laterals are also used where mountainous terrain is a problem (Lance Cook, Union Pacific Resources Company, verbal communication, 1997).

Horizontal wells in the Utah thrust belt are completed open hole or through pre-perforated liners using submersible electric pumps. Problems include casing collapse in horizontal laterals and scale caused by certain water chemistries; the latter requires a scale-inhibitor program.

Drilling programs and production: By 1990, Pineview, Lodgepole, and Elkhorn Ridge fields were nearing depletion. Union Pacific Resources Company (UPRC), operator of the three fields, had gained high-quality experience drilling horizontal wells in the Gulf Coast Austin Chalk play, another fractured reservoir. Union Pacific Resources Company felt that horizontal drilling could recover additional oil from the fractured Twin Creek Limestone in the three Utah fields. The horizontal drilling programs required exceptions to spacing orders by the Utah DOGM. New spacing for horizontal drilling units was also approved that allowed two horizontal wells in the same formation but in two different members, the Rich and Watton Canyon.

Two horizontal wells were drilled in the Pineview field, four in the Lodgepole field, and five in the Elkhorn Ridge field. A horizontal lateral was drilled in the Rich Member of the Twin Creek at Lodgepole and Elkhorn Ridge fields; both proved uneconomical. All the other horizontal laterals were drilled in the Watton Canyon Member of the Twin Creek (figure 4-4).

As of August 1, 2008, horizontal wells have produced 58,400 bbls of oil (BO) (9300 m^3) at Pineview field, 395,400 BO (62,900 m^3) at Lodgepole field, and 1,101,800 BO (175,200 m^3) at Elkhorn field, for a total contribution of 1,555,600 BO (247,300 m^3) (Utah Division of Oil, Gas and Mining, 2008) (table 13-1). Most of these horizontal wells produced a large volume of water because they were drilled in nearly depleted fields and in structurally complex settings. Commonly a horizontal well may produce 100% water for the first several months as drilling fluids are flushed back into the wellbore. Oil production then gradually begins and increases (Hart's Oil and Gas World, 1995).

Case-Study Fields

Pineview field, Utah: Pineview field (figure 3-1) was discovered in 1975 and has produced over 31,000,000 bbls (4,900,000 m^3) of oil and 39.3 billion cubic feet (BCF [1.1 BCM]) of gas from the Jurassic Nugget, Twin Creek, and Stump Formations, and the Cretaceous Kelvin Formation (Utah Division of Oil, Gas and Mining, 2008). The trap is a rollover anticline with four-way closure (figures 3-12, 3-13, 13-4, and 13-5). The productive area is about 2180 acres (880 ha) (Cook and Dunlevay, 1996). Open fractures trend in a west-northwest direction.

Most of the production is from the Nugget and Twin Creek Formations. Two horizontal wells, the Bingham No. 2-6 H (SW1/4SW1/4 section 2, T. 2 N., R. 7 E., Salt Lake Base Line and Meridian [SLBLM]) and the UPRC No. 3-11 H (SW1/4SW1/4 section 3, T. 2 N., R. 7 E.,

SLBLM) were drilled in the Watton Canyon Member of the Twin Creek in 1997. Both horizontal lengths were nearly 3000 feet (1000 m) in a north-northeast direction (figure 13-4).

The two horizontal wells produced 58,000 BO (9200 m^3), 89 million cubic feet of gas (MMCFG [2.5 MMCMG), and 105,000 bbls of water (BW [16,700 m^3]), with more than 96% of the hydrocarbon production coming from the Bingham No. 2-6 H well (figure 13-6).

Lodgepole field, Utah: Lodgepole field (figures 3-1 and 4-1) was discovered in 1976 and has produced over 2,100,000 million bbls (330,000 m^3) of oil and 0.74 BCF (0.021 BCM) of gas from the Nugget and Twin Creek Formations (Utah Division of Oil, Gas and Mining, 2008). The trap is a rollover anticline with four-way closure that is divided into two blocks by northeast-southwest-trending splay faults (figures 13-7 and 13-8). The structure is further divided into several subsidiary folds and an east-west-trending structural nose. The productive area is about 640 acres (260 ha) (Benson, 1993a). The dominant open fracture trend is northwest to southeast.

Three horizontal wells, the Blonquist No. 26-1H (NE1/4NE1/4 section 26, T. 2 N., R. 6 E., SLBLM), Judd No. 34-1 H (SW1/4SW1/4 section 34, T. 2 N., R. 6 E., SLBLM) with two laterals, and the UPRR No. 35-2 H (NW1/4NW1/4 section 35, T. 2 N., R. 6 E., SLBLM) with two laterals, were drilled in the Watton Canyon Member of the Twin Creek Limestone from 1993 through 1996. Horizontal lengths were nearly 3500 feet (1200 m) in north-northeast, east, south, and south-southwest directions depending on their locations on the complex Lodgepole structure (figure 13-7).

Only the Nos. 34-1H and 35-2H wells are productive totaling 394,000 BO (62,600 m^3), 75 MMCFG (2.1 MMCMG), and 202,000 BW (32,100 m^3) (Utah Division of Oil, Gas and Mining, 2008) (figure 13-9).

Elkhorn Ridge field, Utah: Elkhorn Ridge field (figure 4-1) was discovered in 1977 and has produced over 1,800,000 million bbls (290,000 m^3) of oil and 0.85 BCF (2,400,000 m^3) of gas from the Twin Creek Limestone (figure 13-10) (Utah Division of Oil, Gas and Mining, 2008). Like the other fields on the trend, the trap is a rollover anticline with four-way closure (figures 13-11 and 13-12). The productive area is about 2560 acres (1040 ha) (Benson, 1993b). Elkhorn Ridge field will be discussed in greater detail because it produces solely from the Twin Creek and the horizontal drilling program was the most successful of the three Utah case-study fields.

The discovery well, the UPRC No. 19-1 (SW1/4NE1/4 section 19, T. 2 N., R. 7 E., SLBLM), was completed in the Rich Member of the Twin Creek Limestone. The UPRC No. 19-2 well (SW1/4NW1/4 section 19, T. 2 N., R. 7 E., SLBLM), drilled in 1979, was completed in the Watton Canyon Member. The Newton Sheep No. 18-1 well (SW1/4SE1/4 section 18, T. 2 N., R. 7 E., SLBLM) was completed in the Watton Canyon in 1987 (figure 13-13). The UPRC No. 17-1 well (SE1/4NW1/4 section 17, T. 2 N., R. 7 E., SLBLM) was drilled and temporarily abandoned in 1988; it was converted to a Nugget Sandstone salt water disposal well in 1993. From 1993 through 1995, four horizontal wells, the UPRC No. 17-2 H (SW1/4SW1/4 section 17, T. 2 N., R. 7 E., SLBLM), UPRC No. 19-2X H (SW1/4NW1/4 section 19, T. 2 N., R. 7 E., SLBLM), Newton Sheep No. 20-1 H (NW1/4NW1/4 section 20, T. 2 N. R. 7 E., SLBLM) with two laterals, and the Newton Sheep No. 24-1 H (NE1/4NE1/4 section 24, T. 2 N., R. 6 E., SLBLM), were drilled in the Watton Canyon Member of the Twin Creek. An early attempt, the UPRC No. 19-2 1 H well (SW1/4NW1/4 section 19, T. 2 N., R. 7 E., SLBLM), resulted in lost tools in the hole and was junked and abandoned in 1984. The four horizontal wells have

produced 1,102,000 BO (175,200 m^3), 523 MMCFG (14.8 MMCMG), and 1,285,000 BW (204,300 m^3) (Utah Division of Oil, Gas and Mining, 2008) (figure 13-14).

The Watton Canyon Member of the Twin Creek Limestone is a low matrix, thinly bedded argillaceous limestone. The majority of the production is from the existing fracture system. Based on outcrop studies, formation imaging logs, and production data, UPRC determined the open fractures predominately trend northwest-southeast and dip to the southwest and northeast at about 60 degrees, parallel to the northwest flank of the structure. Fractures that trend north-northwest to south-southeast are generally closed and healed with mineral deposits (Utah Division of Oil, Gas and Mining, 2003d).

The upper 100 feet (30 m) of the Watton Canyon Member contains uneconomical volumes of hydrocarbons. The lower 190 to 200 feet (58-61 m) of the Watton Canyon can be economically productive if fractures are present. However, the bottom 100 feet (30 m) is less argillaceous and more likely to be fractured (Utah Division of Oil, Gas and Mining, 2003d). The target for the horizontal drilling was a 25- to 30-foot-thick (8-9 m), intensely fractured zone or "sweet spot" near the bottom of the Watton Canyon (figure 13-13). The four producing horizontal laterals average 2994 feet (912 m) (Appendix I) within the 200-foot-thick (60-m) gross pay section, and 2216 feet (675 m) within the 25- to 30-foot-thick (8-9 m) "sweet spot" (Utah Division of Oil, Gas and Mining, 2003d).

The Elkhorn (Watton Canyon) Unit is an enhanced oil recovery unit that was approved for waterflood operations on July 30, 2003. The unit includes all of sections 17, 18, 19 and 20, T. 2 N., R. 7 E, SLBLM. The waterflood project uses the horizontal Newton Sheep No. 20-1H well for water injection and two horizontal wells, the UPRC Nos. 17-2H and UPRR 19-2X H, and one vertical well, the Newton Sheep No. 18-1, for production. The waterflood project calls for an average injection rate of 2250 BW/D (360 m^3/D) with a maximum injection pressure of 2000 pounds per square inch (psi [14,000 kPa]). The operator expects the waterflood to recover an additional 165,000 BO (26,200 m^3). Water injection into the Newton Sheep No. 20–1H well began in November 2003. Through 2004, the average injection rate was about 1300 BW/D (200 m^3/D) without any increase in oil production.

Painter Reservoir and Ryckman Creek fields, Wyoming: The principal reservoir for Painter Reservoir and Ryckman Creek fields (figure 3-1) is the Nugget Sandstone. Like most Utah-Wyoming thrust belt fields, they represent hanging-wall anticlines formed as rollovers into a thrust splay (as shown for Painter Reservoir field in figures 13-15 and 13-16). These fields were discovered early in the successful exploration of the thrust belt: Ryckman Creek in 1976 and Painter Reservoir in 1977 shortly after the initial thrust belt discovery in Utah of Pineview field (figure 3-1). Nearly 90 wells have been drilled in the two fields and there is a wealth of publicly available information.

Besides lithologic heterogeneity within the Nugget Sandstone, the folding and faulting that created the hydrocarbon traps produced both open and closed fractures. The results are potential undrained compartments ideally suited to be encountered by horizontal drilling (Wyoming Oil and Gas Conservation Commission, 1998b). Horizontal drilling (new horizontal wells and horizontal laterals (less than 500 feet [150 meters]) in these thrust belt fields also improved areal connectivity of the wellbore and productive strata, improved drainage geometry, reduced coning and cusping, reduced the tendency to produce sand along with hydrocarbons, increased sweep efficiency of the nitrogen and waterfloods (discussed later), and reduced field development costs, thus allowing increased oil recovery. Well-placed horizontal wellbores

increase overall field recovery by 0.5 to 1.5%. Applying this technology to injection wells also helps improve pressure maintenance performance (Wyoming Oil and Gas Conservation Commission, 1998c).

Ryckman Creek field was shut-in in 2000 after producing 19,519,194 bbls (3,103,552 m^3) of oil. However in 2001, Painter Reservoir field remained one of most prolific active oil fields in Wyoming, ranking 12th in annual oil production – 891,237 bbls (141,707 m^3) from 33 wells (Wyoming Oil and Gas Conservation Commission, 2001). The gas-injection, pressure-maintenance program begun in 1978 and the tertiary, nitrogen-miscible program begun in 1981 both continue to perform well. Eight successful horizontal wells have also been drilled in Painter Reservoir field (one horizontal well was drilled in Ryckman Creek) and that program is ongoing (well records, Wyoming Oil and Gas Conservation Commission). The field has produced over 44 million bbls (7 million m^3) of oil and serves as an excellent example of best practices for Nugget Sandstone reservoirs in the Utah-Wyoming thrust belt.

Miscible Nitrogen Injection

Miscible nitrogen injection was employed in the later development of Painter Reservoir field (figure 3-1) to enhance the ultimate recovery of oil. Reservoir compositional simulation studies were conducted showing that the field had an estimated ultimate recovery of 45 million bbls (7.2 million m^3) of oil under primary depletion of the 166 million bbls (26.4 million m^3) of original oil in place (a 27% recovery factor). A waterflood with gas-cap cycling increased the ultimate recovery to 88 million bbls (14 million m^3) of oil (a 53% recovery factor). This process uses nitrogen injection to cycle the gas out of the gas-condensate system while simultaneously waterflooding the oil zone. Ultimate recovery was also determined for a tertiary, miscible nitrogen-injection program. In this process, nitrogen and hydrocarbon gas are over-injected into the reservoir to raise the reservoir pressure to miscible conditions. This would yield an ultimate recovery of 97 million bbls (15 million m^3) of oil (a 59% recovery factor). The simulation further indicated that when the miscible nitrogen-injection program is supplemented with water injection, the ultimate recovery would be 113 million bbls (18 million m^3) of oil (a 68% recovery factor) (Wyoming Oil and Gas Conservation Commission, 1981a).

In the miscible nitrogen-injection program, nitrogen gas is injected into the gas cap at the crest of the Painter Reservoir structure (figures 13-15 and 3-11). Over time, both the gas cap and the nitrogen are displaced downward into the oil-bearing part of the reservoir leaving little residual oil behind. Supplemental water is injected below the oil/water contact to minimize oil movement downward into the water-bearing part of the Nugget reservoir. The overall result is a very efficient miscible recovery of oil where nitrogen will affect all wells in the field whether they are below the original gas cap or to the side of it. The program was designed to extend over a life of 60 years (Wyoming Oil and Gas Conservation Commission, 1981a, 1981b).

Retrograde Condensate Production

Condensate production is common in Absaroka thrust - Mesozoic-cored deep structures (figure 3-14). In retrograde condensate reservoirs, the fluid changes from a single-phase rich gas to a two-phase gas and liquid mixture when the pressure drops below the dew-point pressure (Kloepper, 1993). Without pressure maintenance, the retrograde condensate remains in the reservoir and wells are less productive. The Nugget Sandstone in Anschutz Ranch East field

(figures 3-1 and 3-14) is a major retrograde reservoir where pressure maintenance operations have successfully maximized recovery. Condensate production under the pressure maintenance program covers the expense of the operation and positively affects the economics (Kloepper, 1993).

The following description of the best practices for condensate production was taken, with some modifications and updates, from "Maximizing Condensate Recovery in a Rich Gas Reservoir" by Welch (1993) in the "Atlas of Major Rocky Mountain Gas Reservoirs."

Introduction

Retrograde gas condensation occurs when a reservoir containing a single-phase gas forms a liquid phase while undergoing isothermal expansion during pressure depletion (Katz and others, 1959). Liquid condensate is first formed in the reservoir when the pressure of the expanding reservoir gas drops below the dew-point pressure. When liquid condenses in the reservoir, it can cause several adverse effects. The more common of these are a reduction in ultimate condensate recovery, a reduction in gas deliverability, and a reduction in ultimate gas recovery from that expected in the absence of liquid condensation. Depending on reservoir characteristics and/or reservoir fluid-phase behavior, the adverse effects associated with retrograde condensation can often be economically prevented or minimized. Anschutz Ranch East field (figure 3-1) is an example of an attempt to minimize retrograde condensate losses through implementation of a full pressure maintenance project. Pressure maintenance has been achieved in this field by injecting a mixture of dry hydrocarbon gas and nitrogen.

Although full pressure maintenance is the most effective way to alleviate the problems associated with retrograde condensation, it is not always economical to implement. Therefore, the virtues of depleting a reservoir under partial pressure maintenance and/or gravity drainage mechanisms should not be overlooked. Detailed reservoir analysis must be coupled with the analysis of surface facility design to identify the optimum development plan.

Methods

For a given reservoir temperature, retrograde condensate gas reservoirs lie between volatile oil and dry gas reservoirs in terms of molecular composition. As is true for all reservoirs, tests should be performed in a retrograde condensate reservoir to determine the reservoir fluid composition and its phase behavior. Caution must be exercised in sampling retrograde condensate fluids to ensure that the samples gathered are representative of the in-situ fluids because phase changes can take place during sampling. Surface separation studies should be conducted to determine the optimum separator stages to maximize condensate recovery from the produced gas.

An example of retrograde condensation is demonstrated in the constant composition expansion phase diagram of a hydrocarbon mixture (figure 13-17). The fluid initially exists at reservoir and temperature conditions indicated by point L. Until the pressure declines below the dew point (point D), only free gas exists. At the dew point, the first drops of liquid form. Between the dew point and point G, retrograde condensation is occurring and the liquid saturation is increasing. Between points G and

E, retrograde vaporization is occurring and the liquid saturation is decreasing. Reducing the pressure to below point E will cause the mixture to pass back through the dew point and all the condensate will revaporize.

Although figure 13-17 is an accurate laboratory description of the phase behavior for a system undergoing a constant composition expansion, liquid that is condensed in the reservoir usually is not recoverable under primary pressure depletion (in the absence of water influx, reservoir depletion is more closely related to a constant volume depletion process). The reduction in condensate recovery is associated with a shift in the reservoir composition toward a heavier composition as the lighter components are withdrawn from the reservoir in the form of gas production. This shifting composition depresses the lower portion of the dew-point curve (figure 13-17) making revaporization of the retrograde liquid more difficult. Condensate saturations will be highest in the vicinity of producing wells because of pressure drawdown and some migration of condensate to the wellbore area. Larger condensate dropout zones exist in the vicinity of the wellbores in lower-permeability reservoirs because of the need for larger pressure gradients to maintain a given level of well production.

Normally, any operating procedure that prevents reservoir pressure decline will have a positive effect on field recovery. However, pressure support through an aquifer and/or water injection may have more detrimental effects on ultimate recovery than the advantages of restricted pressure decline because of the trapping or bypassing of gas by the water front.

Generally, the best way to prevent or reduce retrograde losses in the reservoir is to implement a pressure maintenance project by gas injection. Partial pressure maintenance can be accomplished by re-injection of the produced gas after processing to remove liquids or heavy components. Full pressure maintenance can be achieved through the injection of a nonreservoir gas, such as nitrogen, or injecting the produced gas and adding a hydrocarbon make-up gas purchased from another source. Repressuring a depleted or partially depleted retrograde condensate can cause the condensate to partially revaporize and ultimately be produced in the gas-well stream.

Unfortunately, most of the pressure support projects that might be necessary for maximum fluid recovery require early installation of field equipment with major front-end cash investments. In the final analysis, any project to be implemented should be studied well to determine the economic merit of the application of improved recovery. In very general terms, the expected gas and condensate recovery can be estimated for primary depletion by first calculating the amount of sales gas and condensible liquids contained in the reservoir. Recoverable volumes can then be calculated using a recovery factor for each phase from correlations provided by Eaton and Jacoby (1970). Experimental laboratory depletion studies provide a more accurate estimate of expected reservoir performance.

The recovery for the pressure maintenance injection case may also be estimated from the in-place sales gas and condensate volumes. These volumes are converted to recoverable volumes by application of a recovery factor that reflects primarily the volumetric sweep that will be achieved by the injected gas. Volumetric sweep efficiency must be estimated considering placement of the injection wells, vertical heterogeneity of the formation, and gravity segregation tendencies of the reservoir and injected fluids.

Another mechanism that can increase condensate recovery is gravity drainage. In retrograde reservoirs where pressure maintenance is unattractive because of economics and/or poor reservoir or fluid characteristics, additional condensate may be recovered from the base of reservoir. Basement recovery of retrograde condensate is possible anywhere gravity forces can occur in real time (field operating life). This has been observed in the fractured Waterton reservoir in Alberta, Canada (Castelijns and Hagoort, 1984). Basement recovery can occur in both dipping and flat reservoirs. Figures 13-18 and 13-19 illustrate how condensate drainage occurs in a fracture matrix system.

These methods give reasonable approximations of recovery for screening purposes only. More detailed reservoir calculations including reservoir simulation studies should be used for detailed screening and project design.

Anschutz Ranch East Case-Study Field

Anschutz Ranch East, straddling the Utah/Wyoming border, (figure 3-1) is the largest field in the Mesozoic-cored deep structures subplay in terms of hydrocarbon column thickness, cumulative production and reserves, and areal extent (figures 3-15 and 3-16). The reservoir covers approximately 4620 acres (1870 ha) and is divided into two structural lobes. The larger west lobe is a narrow, elongate anticline overturned to the east (Lelek, 1982). Average depth to the Nugget Sandstone in the west lobe is 12,900 feet (4300 m) with more than 2100 feet (700) of closure. When the west lobe reservoir was discovered in 1979, the hydrocarbon column was near the spill point. The smaller east lobe has the same general configuration as the west lobe, and is separated from it by an overturned syncline (Lelek, 1982). Average depth to the Nugget Sandstone in the east lobe is 14,325 feet (4775 m), and it has more than 1000 feet (330 m) of closure. When the east lobe reservoir was discovered in 1981, the hydrocarbon column was also near the spill point (Petroleum Information, 1984b).

The Nugget is 1020 feet (310 m) thick with an average porosity of 10%. The permeability ranges from 0.1 to 400 millidarcies (Lindquist and Ross, 1993). The Nugget formation contains both open fractures and gouge or carbonate-filled fractures (Lelek, 1982). Reservoir performance is affected by fracturing and height above the free-water level (Sercombe, 1989). Cumulative production (figure 13-20) is over 129 million bbls (20.5 million m^3) of condensate, the largest Nugget producer of hydrocarbon liquids in the thrust belt, and nearly 3 trillion cubic feet (85 BCM) of gas (including cycled hydrocarbon gases and nitrogen) (Utah Division of Oil, Gas and Mining, 2008).

According to Metcalfe and others (1985), the field produces a rich (>200 bbls/MMCF [32 m^3/28MCM]) gas-condensate fluid. At the time of discovery, the field was just slightly above (150 to 300 psi [1030-2070 kPa]) the dew-point pressure of 5080 psi (35,000 kPa). Because of the reservoir size and potentially low liquid recovery through retrograde condensation in the reservoir, a plan of depletion had to be determined prior to opening the field to production (Kleinsteiber and others, 1983). The following is a brief summary of how this field was evaluated.

The depletion alternatives considered were pressure maintenance (full and partial) with wet or dry hydrocarbon gases, carbon dioxide, flue gas, and/or nitrogen. Table 13-2 lists advantages and disadvantages, applied to Anschutz Ranch East field, for the different injection gases. Well spacing, injection patterns, and completion strategies also were evaluated. The alternatives were studied initially with a cross-sectional model and

two-dimensional Equation-of-State compositional simulator. From this study, the development plan (spacing and pattern), nitrogen injection plan, and the optimum well completion prognosis were developed.

After the initial scoping study, the reservoir was simulated (Wendschlag and others, 1983) with a full-field, three-dimensional model (an 84 x 20 areal grid and four layers) using both a 9-Component and a 17-Component compositional simulator. This second study was performed to verify past results and improve upon the performance forecasts obtained from the earlier model.

In addition to the simulation studies, an eight-well interference test was performed prior to placing the field in production (Pollock and Bennett, 1986). This test was intended to verify areal continuity and to determine if there was an extensive fracture system and/or any directional orientation to the reservoir flow capacity. The test consisted of placing the Anschutz Ranch East No. 16-20 well in production for 50 days. As shown in figure 13-21, pressure response was monitored in seven wells. It was concluded that the reservoir was continuous and an extensive fracture system did not exist.

Through 1992, Anschutz Ranch East field had been operated under a full pressure maintenance program intended to minimize retrograde condensation. However, the proposed plan of depletion was delayed due to prevailing market conditions, periodic curtailment in gas sales, and other operating/economic conditions. The reservoir pressure has been maintained by injecting the processed (dry) gas stream, which is not sold, and using nitrogen gas to replace the remaining reservoir voidage (figure 13-22).

Partial pressure maintenance was evaluated for Anschutz Ranch East, but the final results indicated that full pressure maintenance would be the most profitable depletion plan. However, partial pressure maintenance by injecting the produced or residue gas after processing can be very attractive in other fields, particularly if a market does not exist for gas sales.

Completion Practices in Covenant Field, Central Utah Thrust Belt – Hingeline

The latest development wells drilled in Covenant field, central Utah thrust belt – Hingeline (figure 1-3B), have been completed with 13-3/8-inch surface casing set to depths of approximately 2000 feet (600 m), 9-5/8-inch intermediate casing set in the Twin Creek Limestone, and 7-inch production casing landed and cemented through the Navajo Sandstone at approximately 6700 feet (2000 m) true vertical depth. The production casing was perforated in selected Navajo intervals with four jet shots per foot. The perforations were broken down using small, 7.5% hydrochloric acid treatments with additives, primarily to clean perforations of clays from drilling muds. Electrical submersible pumps were then installed to artificially lift fluids and the wells were placed in production (Ellis M. Peterson, Wolverine Gas & Oil Corporation, written communication, March 12, 2007). The well spacing is about 40 acres (16 ha) within the Covenant unit. Wells are drilled from three pads and deviated to avoid rugged topography.

Five wells are completed in the lower Navajo unit and five in the upper Navajo unit (figure 5-3); none are commingled (Ellis M. Peterson, Wolverine Gas & Oil Corporation, verbal communication, February 2007). Production facilities at the site include two 10,000-barrel (1600 m^3) storage tanks. Oil is trucked to Salt Lake City or to a pipeline at Montezuma Creek in southeastern Utah. The fully developed cost for this field will be around $56.3 million. Secondary and tertiary recovery programs may include nitrogen injection and/or a carbon dioxide flood (Chidsey and others, 2007).

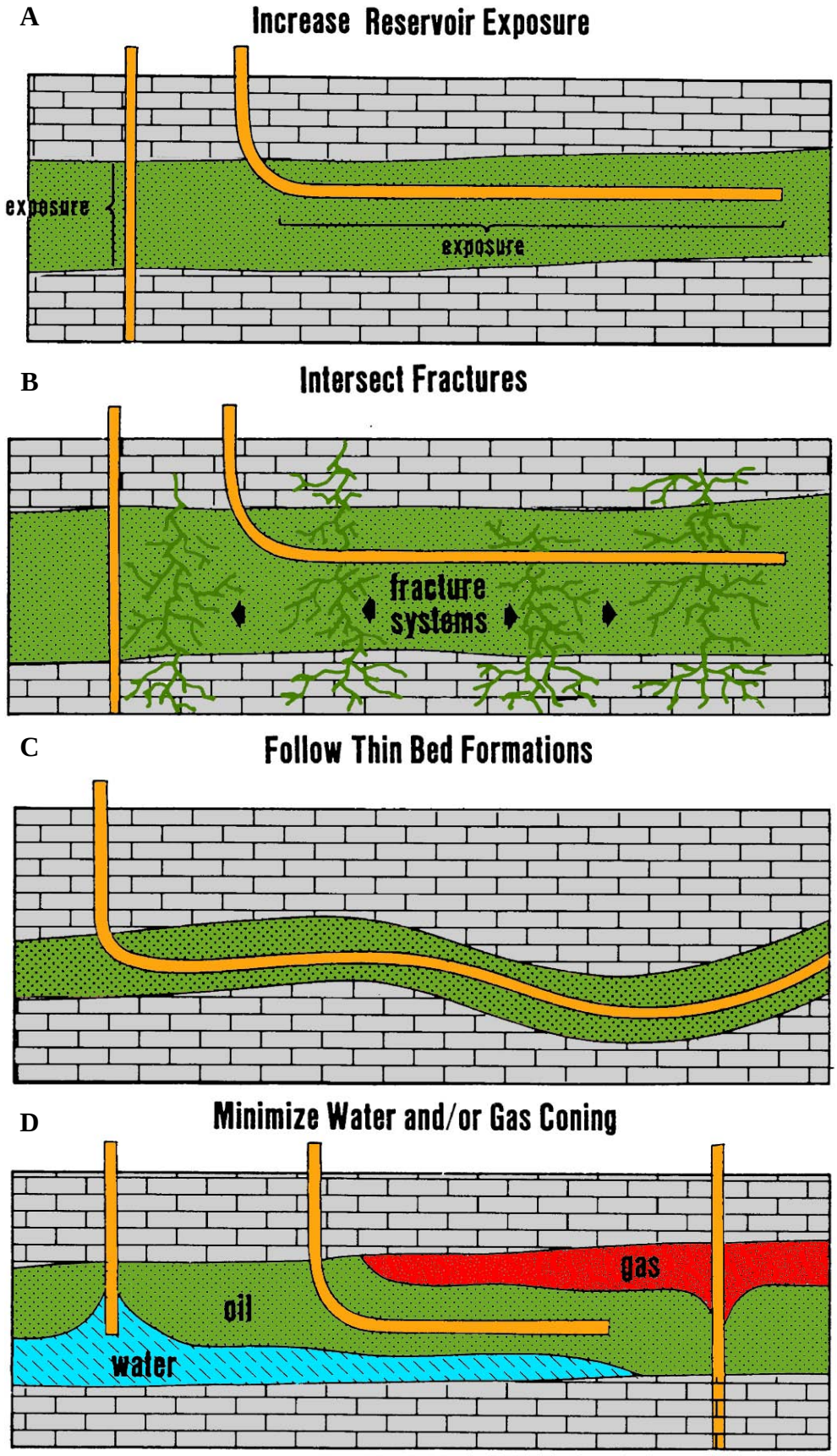


Figure 13-1. Reservoir conditions favorable for horizontal drilling (modified from Kikani, 1993).

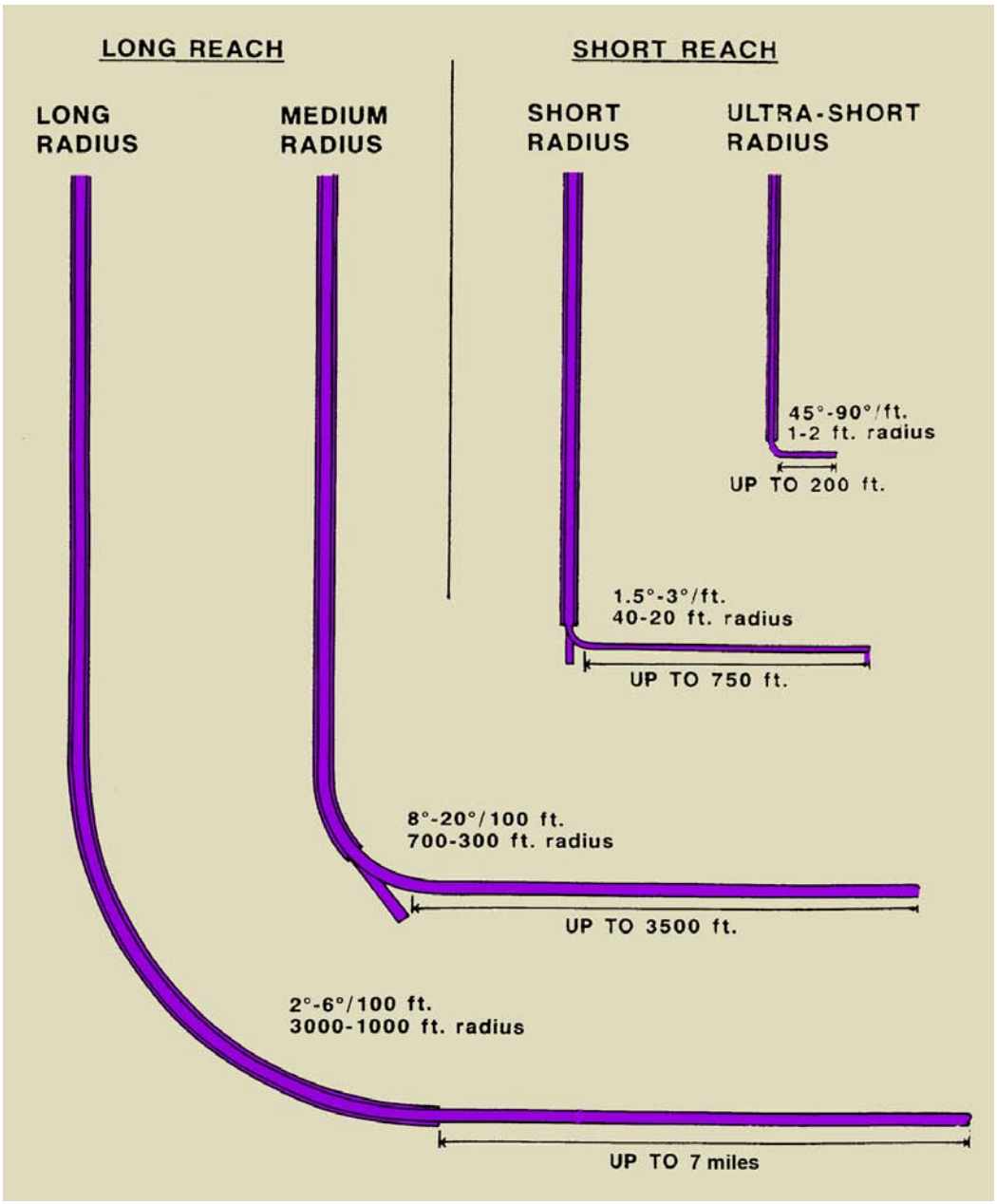


Figure 13-2. Radius of curvature and the angle building ranges for various types of horizontal wells (modified from Fritz and others, 1992).

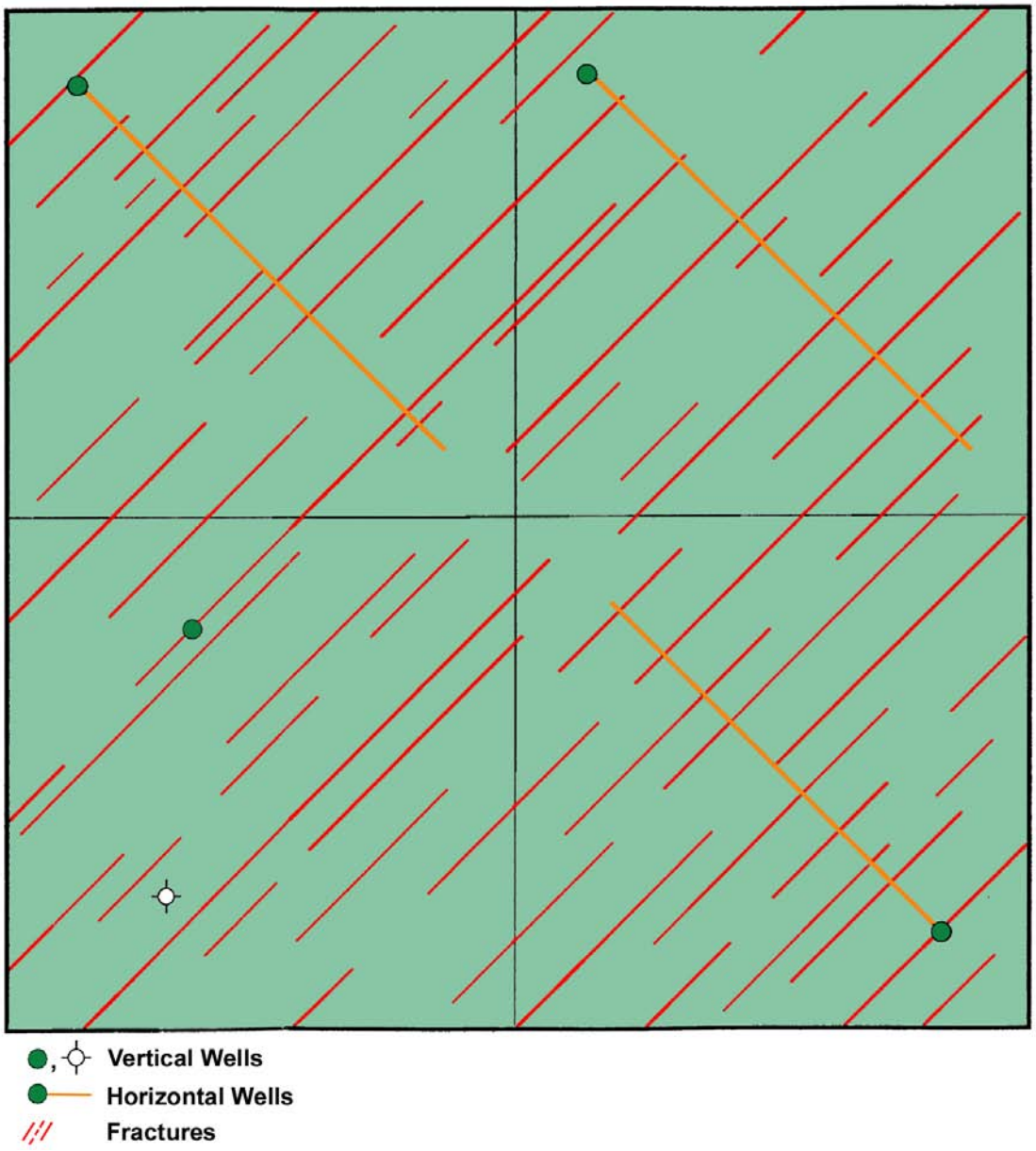


Figure 13-3. Idealized fracture pattern and horizontal well direction. Modified from Utah Division of Oil, Gas and Mining (1994).

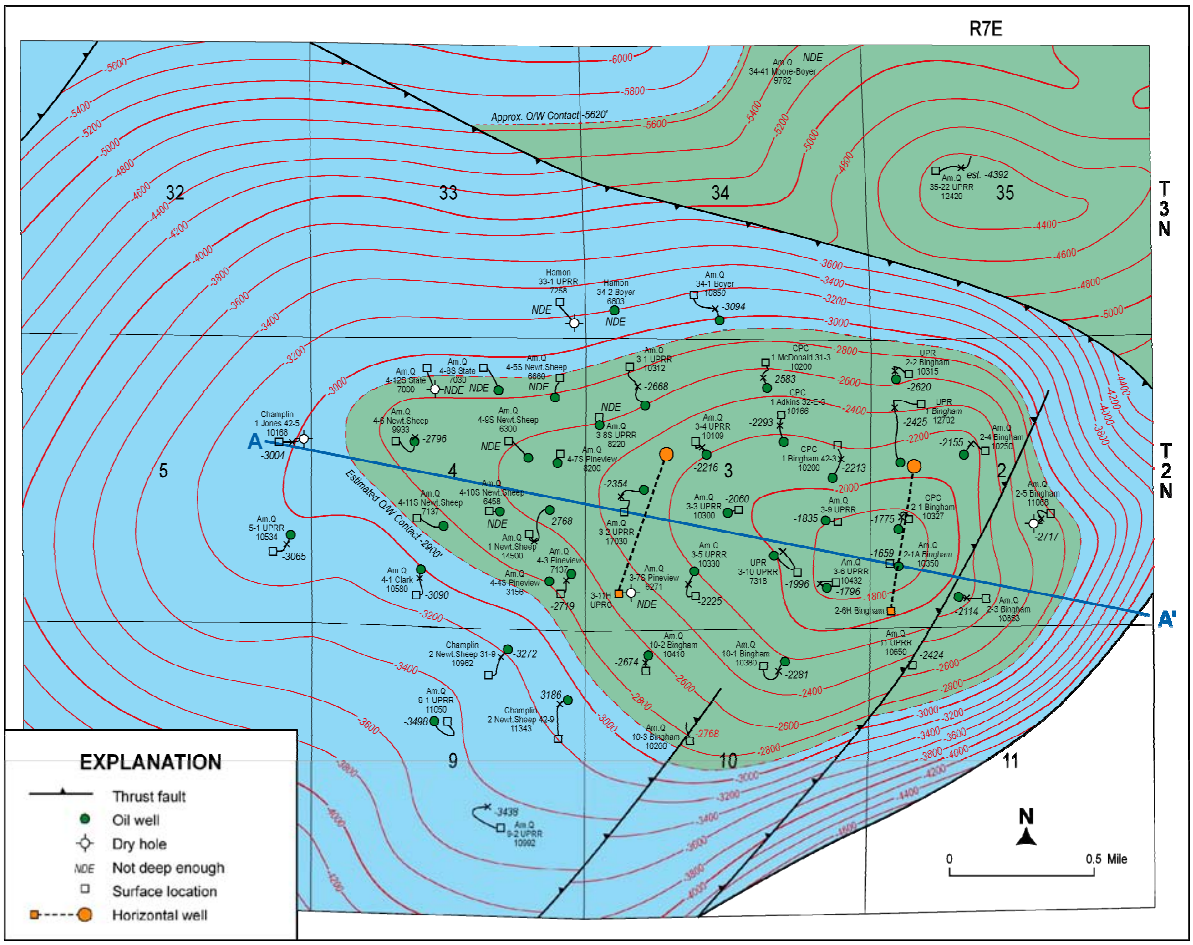


Figure 13-4. Structure contour map of the top of Watton Canyon Member and horizontal wells, Pineview field. Contour interval = 200 feet, datum = mean sea level. Cross section A–A' shown on figure 13-5. Modified from the Utah Division of Oil, Gas and Mining (1997a).

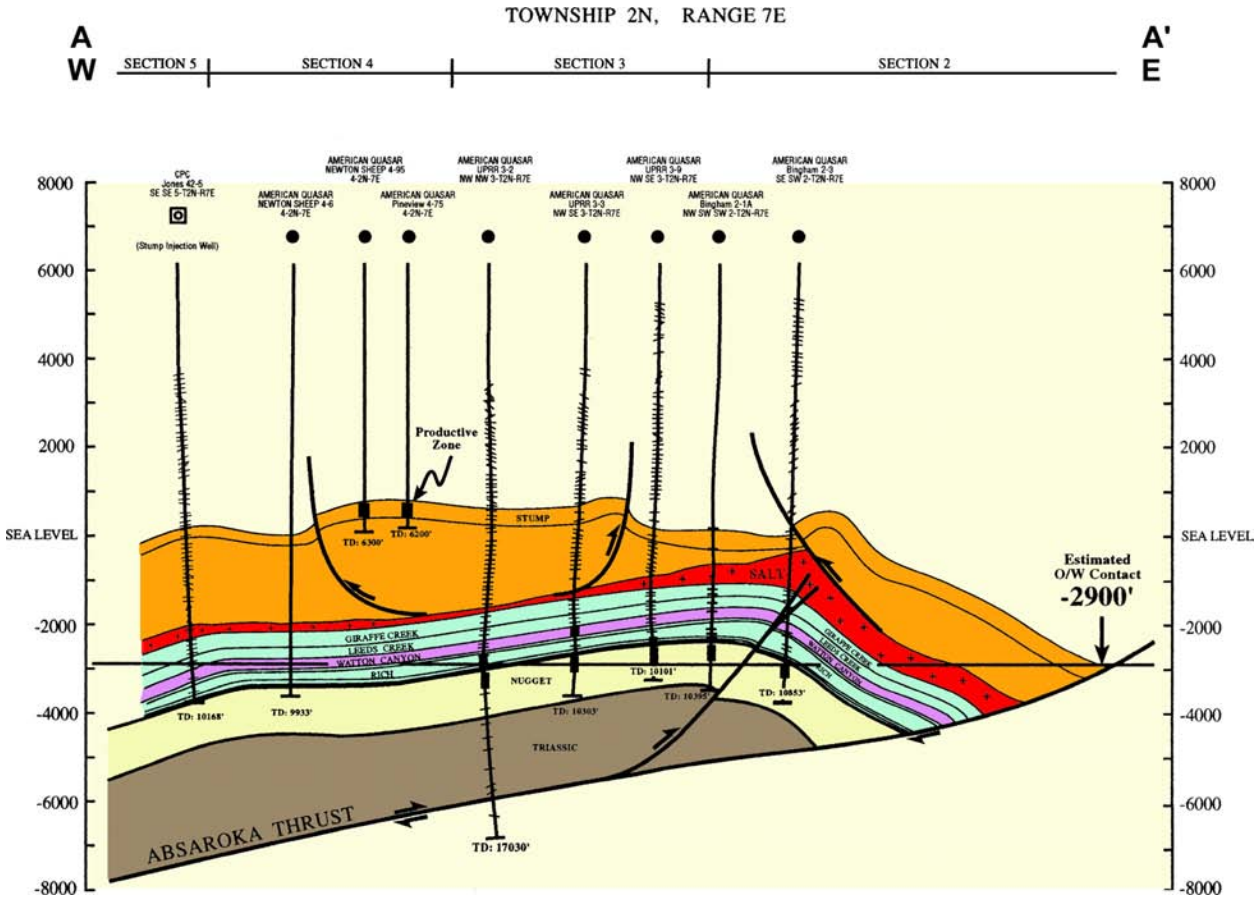


Figure 13-5. Detailed east-west structural cross section through Pineview field. Line of section shown on figure 13-4. The Watton Canyon Member of the Twin Creek Limestone, and primary target for horizontal drilling shown in purple. Dipmeter projections shown on some wellbores. After Utah Division of Oil, Gas and Mining (1997b).

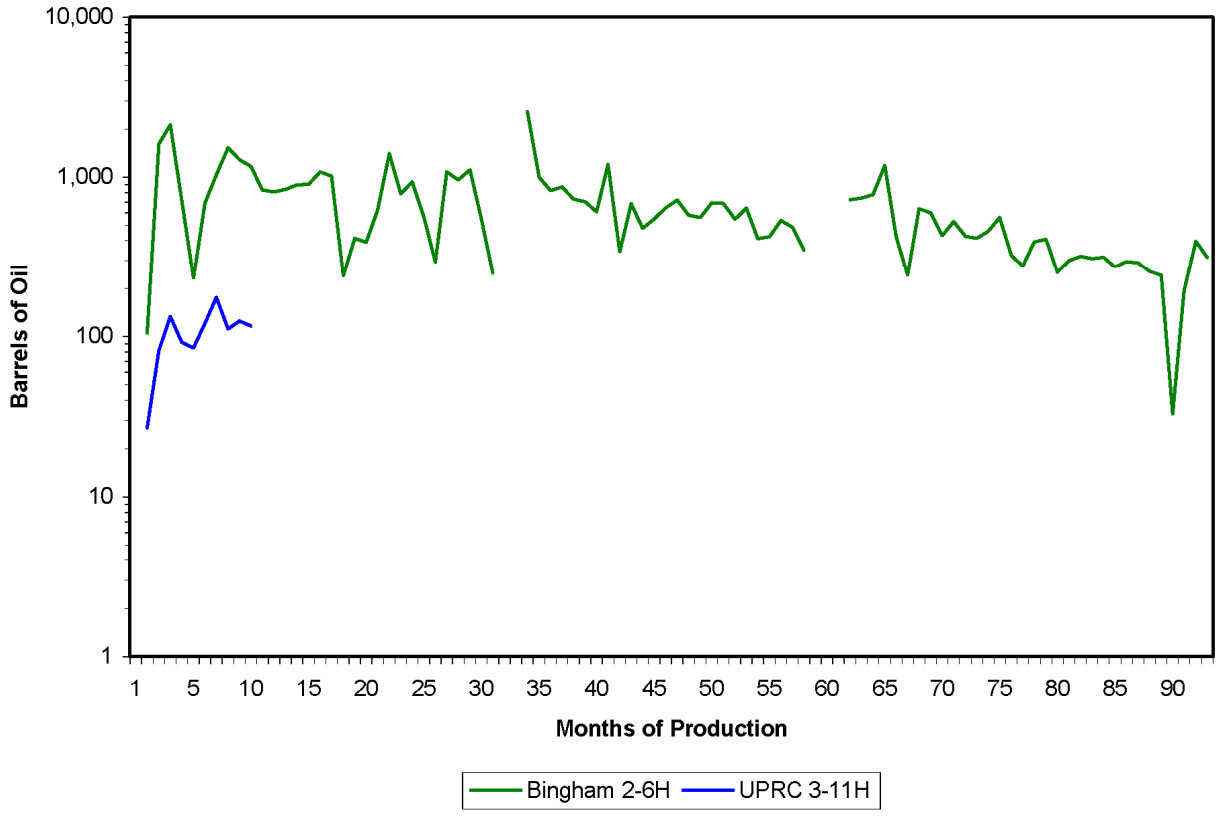


Figure 13-6. Monthly oil production, in barrels, for Pineview field horizontal wells, Bingham Nos. 2-6H and UPRC 3-11H. The UPRC No. 3-11H well only produced for 10 months. Data from Utah Division of Oil, Gas and Mining production records through January 31, 2005.

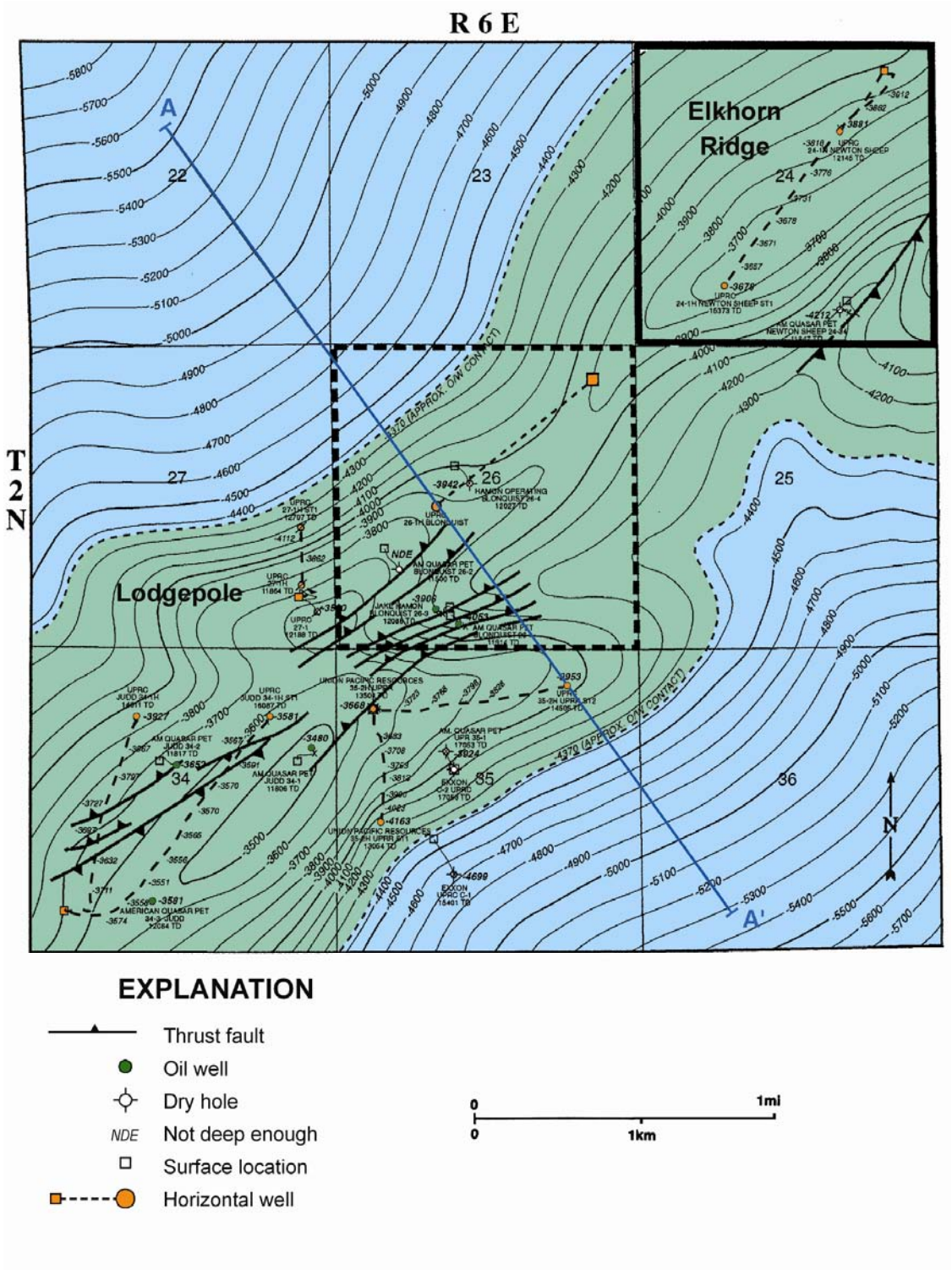


Figure 13-7. Structure map of top of the Watton Canyon Member and horizontal wells, Lodgepole field. Contour interval = 100 feet, datum = mean sea level. Cross section A–A' shown on figure 13-8. Heavy borders represent units. Modified from the Utah Division of Oil, Gas and Mining (1996a).

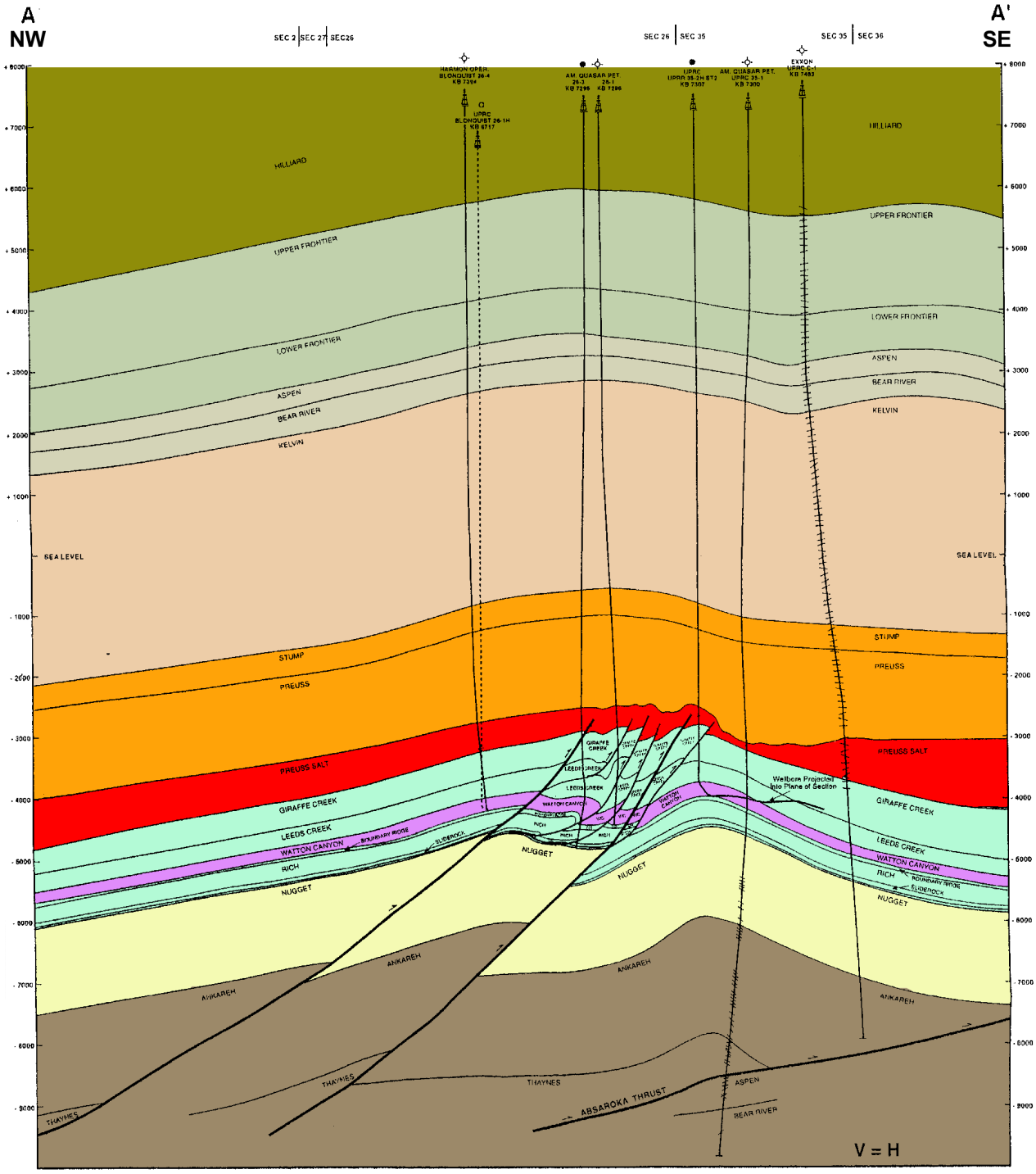


Figure 13-8. Detailed northwest-southeast structural cross section through Lodgepole field. Line of section shown on figure 13-7. The Watton Canyon Member of the Twin Creek Limestone, and primary target for horizontal drilling shown in purple. Dipmeter projections shown on some wellbores. After Utah Division of Oil, Gas and Mining (1996b).

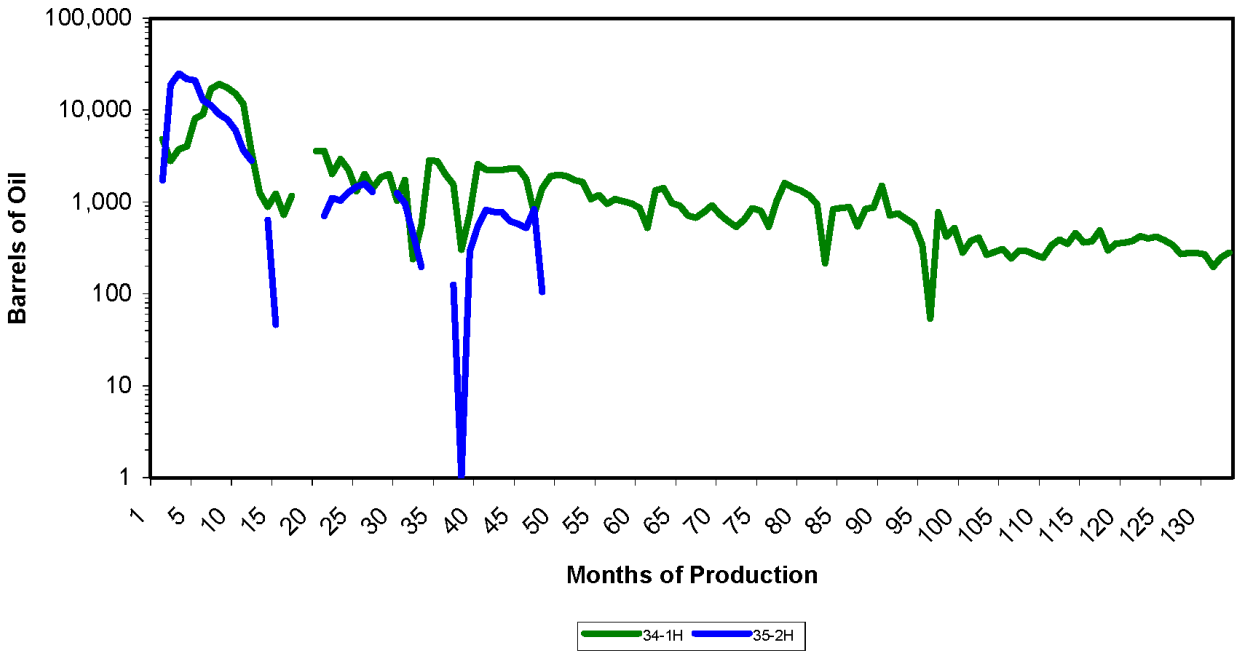


Figure 13-9. Monthly oil production, in barrels, from the Nos. 34-1H and 35-2H horizontal wells in Lodgepole field. Data from the Utah Division of Oil, Gas and Mining production records through January 31, 2005.

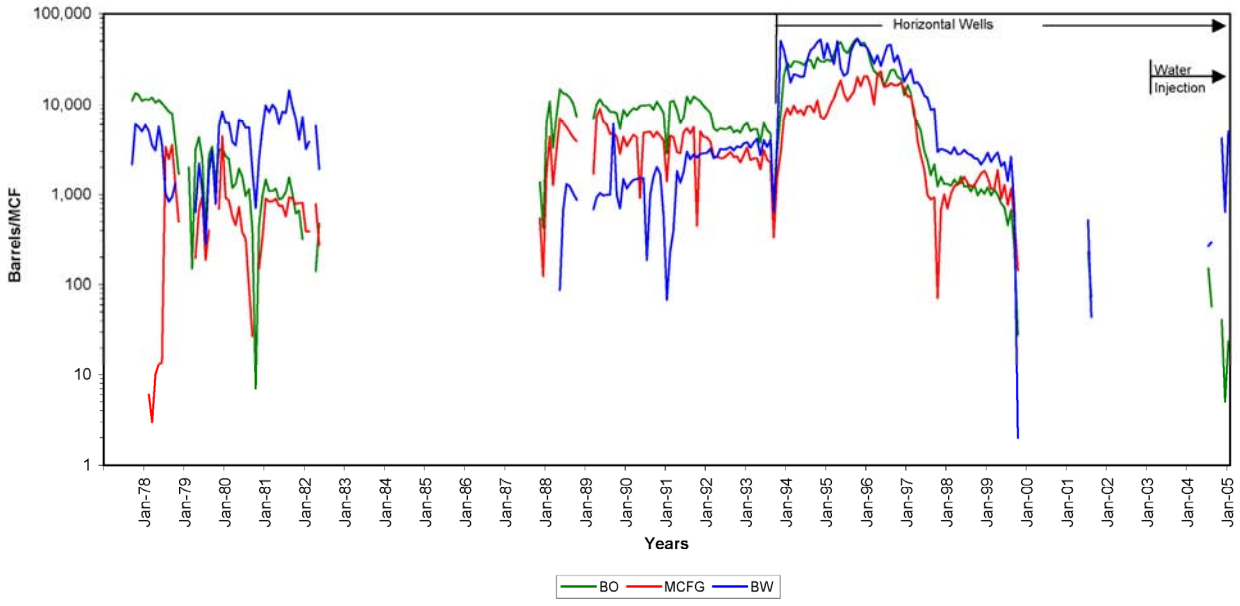


Figure 13-10. Historical production (oil, gas, and water) for Elkhorn Ridge field. Data from Utah Division of Oil, Gas and Mining production records through January 31, 2005.

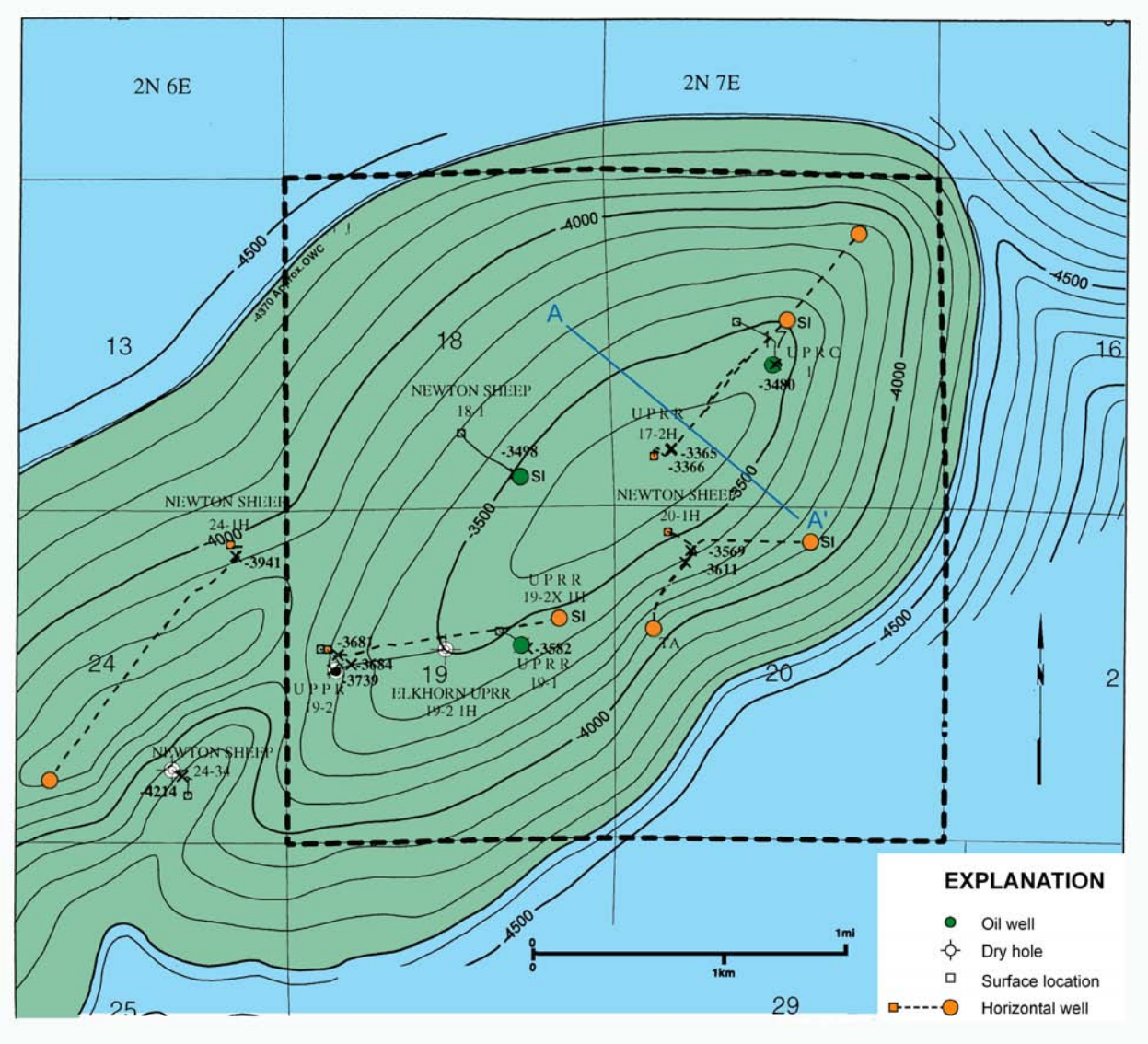


Figure 13-11. Structure map of top of the Watton Canyon Member and horizontal wells, Elkhorn Ridge field. Contour interval = 100 feet, datum = mean sea level. Cross section A–A' shown on figure 13-12. Heavy border represents a unit. Modified from the Utah Division of Oil, Gas and Mining (2003a).

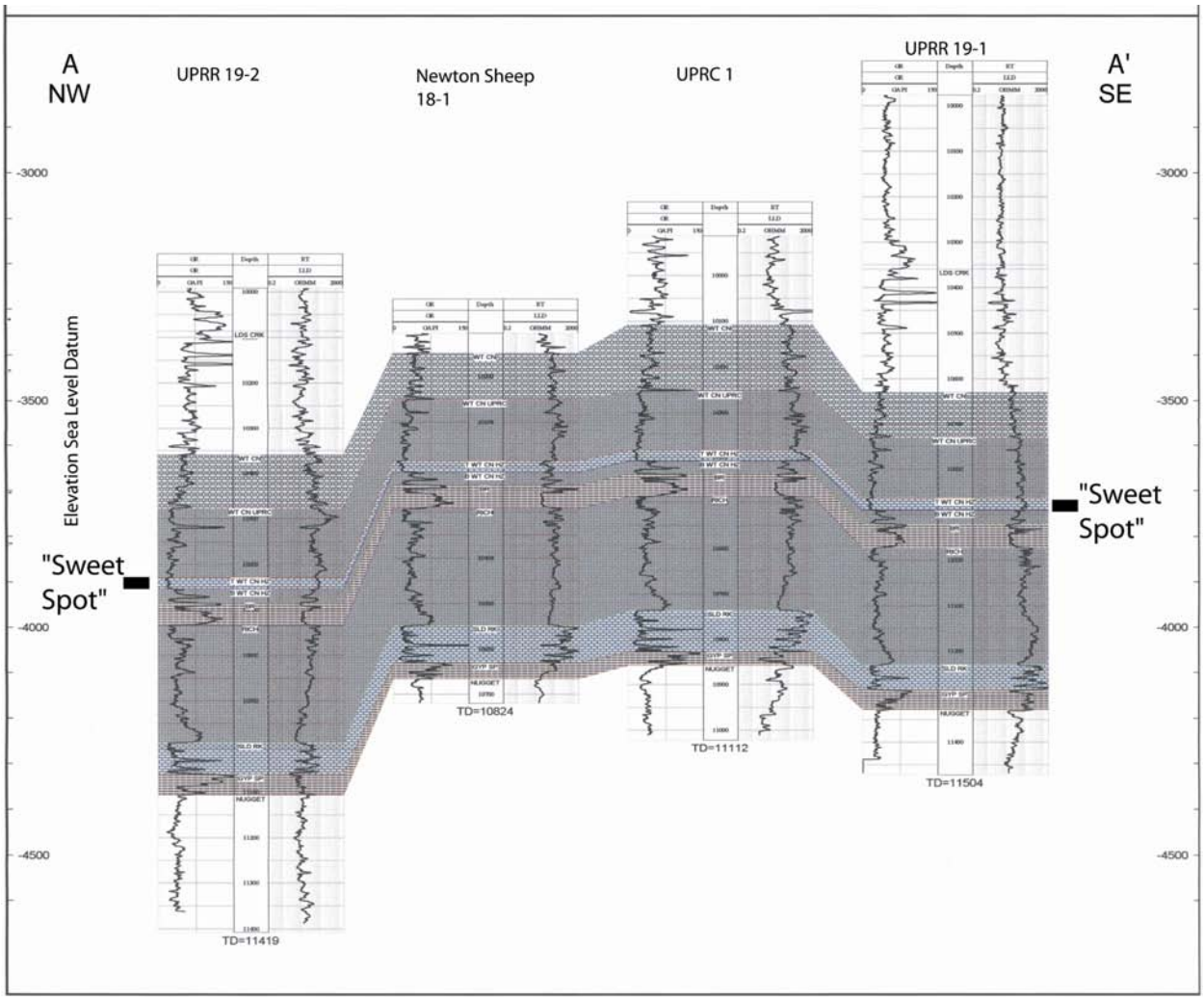


Figure 13-12. Northwest-southeast projected structural cross section of Elkhorn Ridge field using true vertical depth format. The "sweet spot" in the Watton Canyon Member was the primary target of the horizontal drilling. Approximate line of section shown on figure 13-11. After Utah Division of Oil, Gas and Mining (2003b).

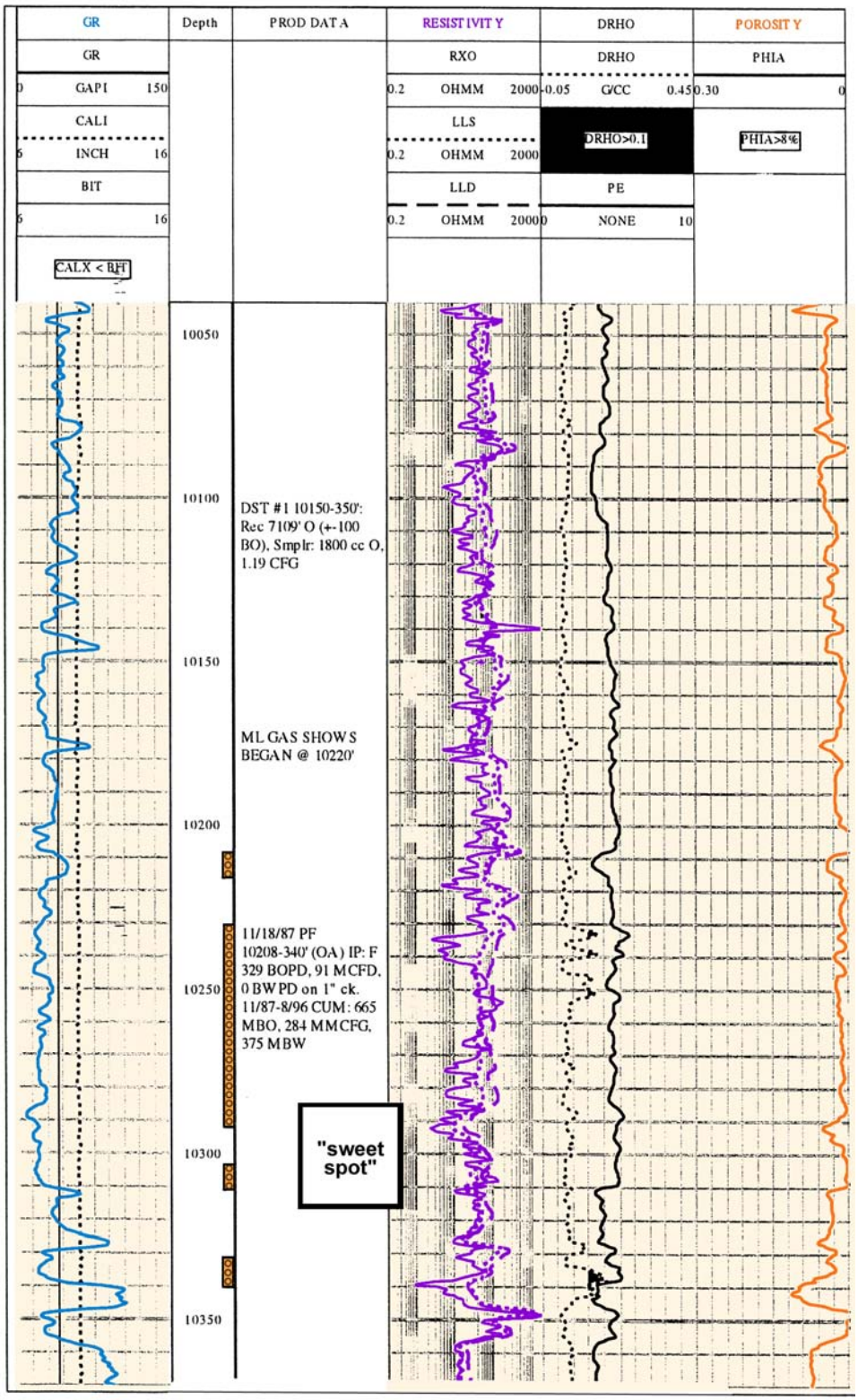


Figure 13-13. Newton Sheep No. 18-1 well type log of the Watton Canyon Member of the Twin Creek Limestone in Elkhorn Ridge field. The "sweet spot" was the primary target of the horizontal drilling. After Utah Division of Oil, Gas and Mining (2003c).

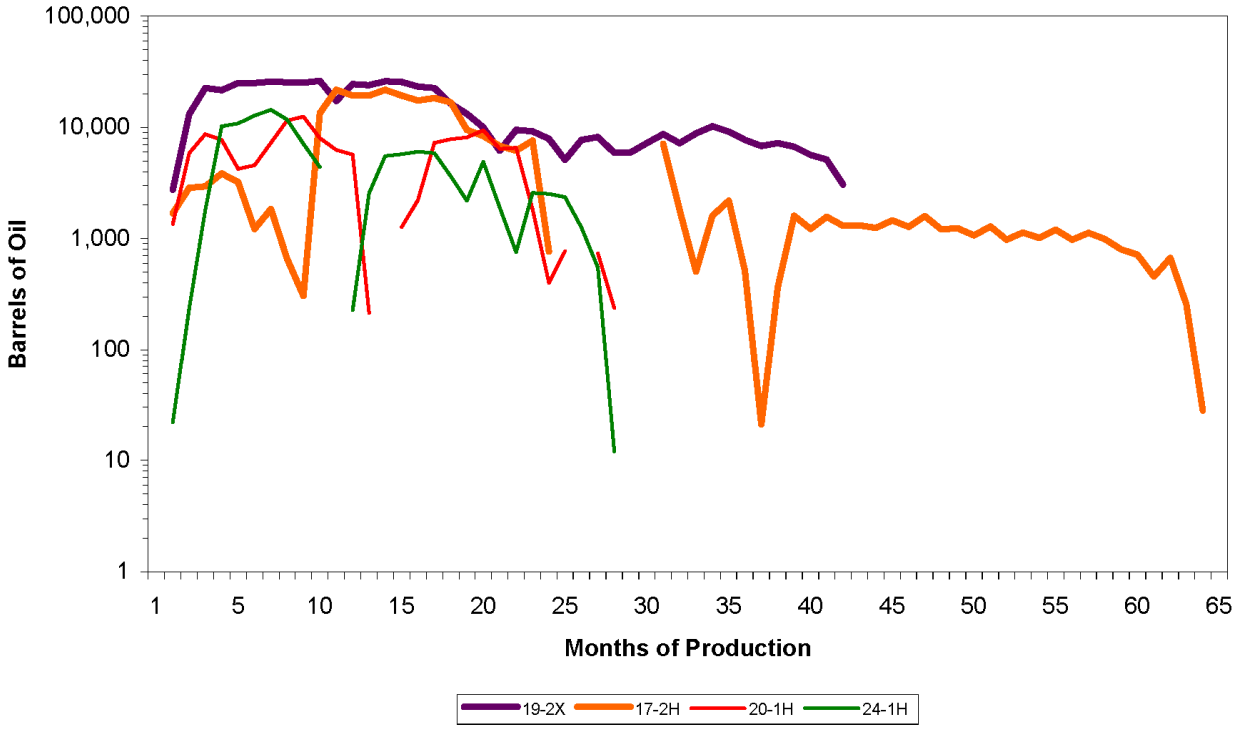


Figure 13-14. Monthly oil production, in barrels, from the four horizontal wells that produce in Elkhorn Ridge field. Data from Utah Division of Oil, Gas and Mining production records through January 31, 2005.

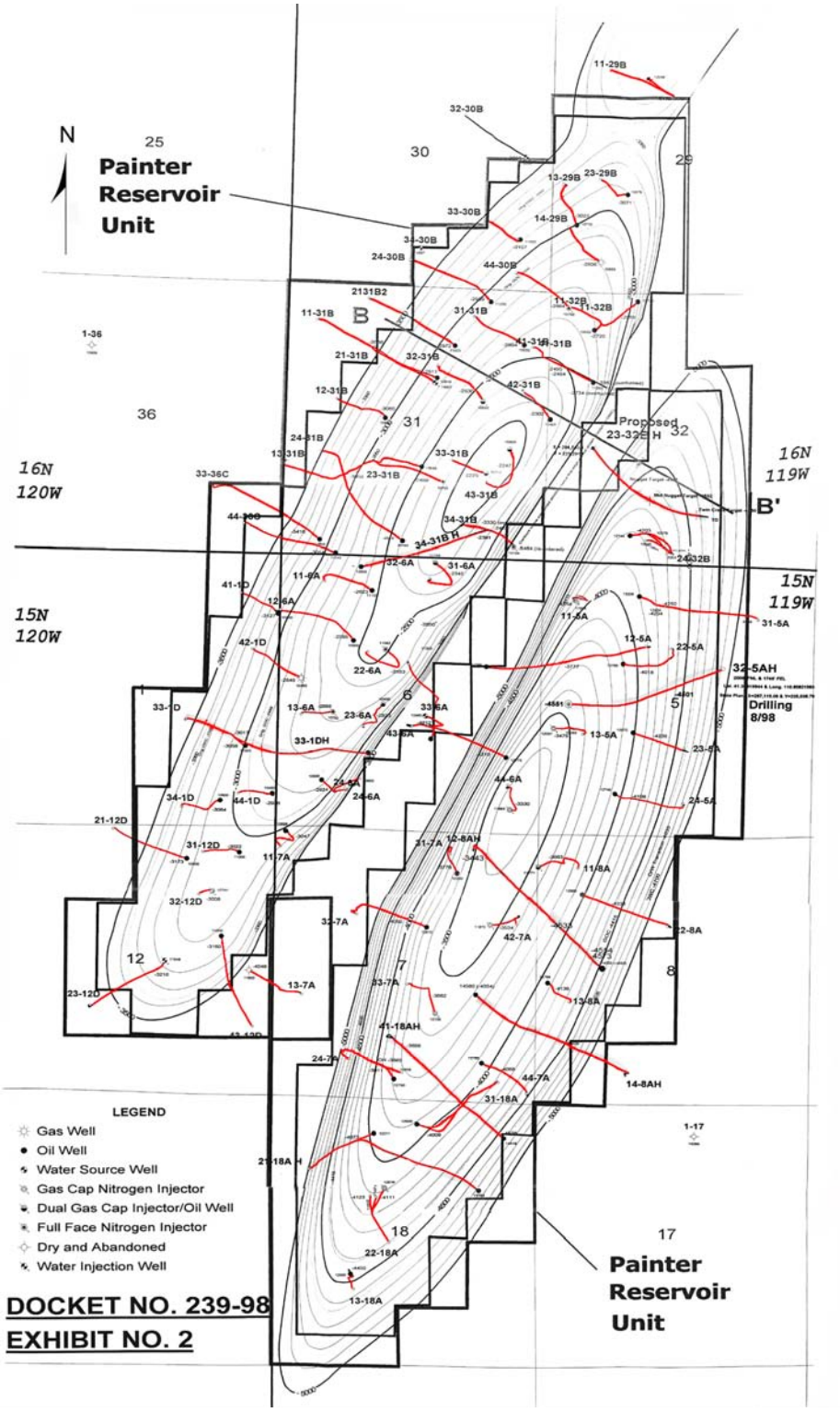


Figure 13-15. Structure contours on top of Nugget Sandstone, Painter Reservoir and East Painter Reservoir fields, Uinta County, Wyoming (after Wyoming Oil and Gas Conservation Commission, 1998c). East Painter Reservoir field is primarily a gas-condensate producer. Horizontal wells - completed, drilling, or proposed – are shown in red. Contour interval = 100 feet, datum = mean sea level.

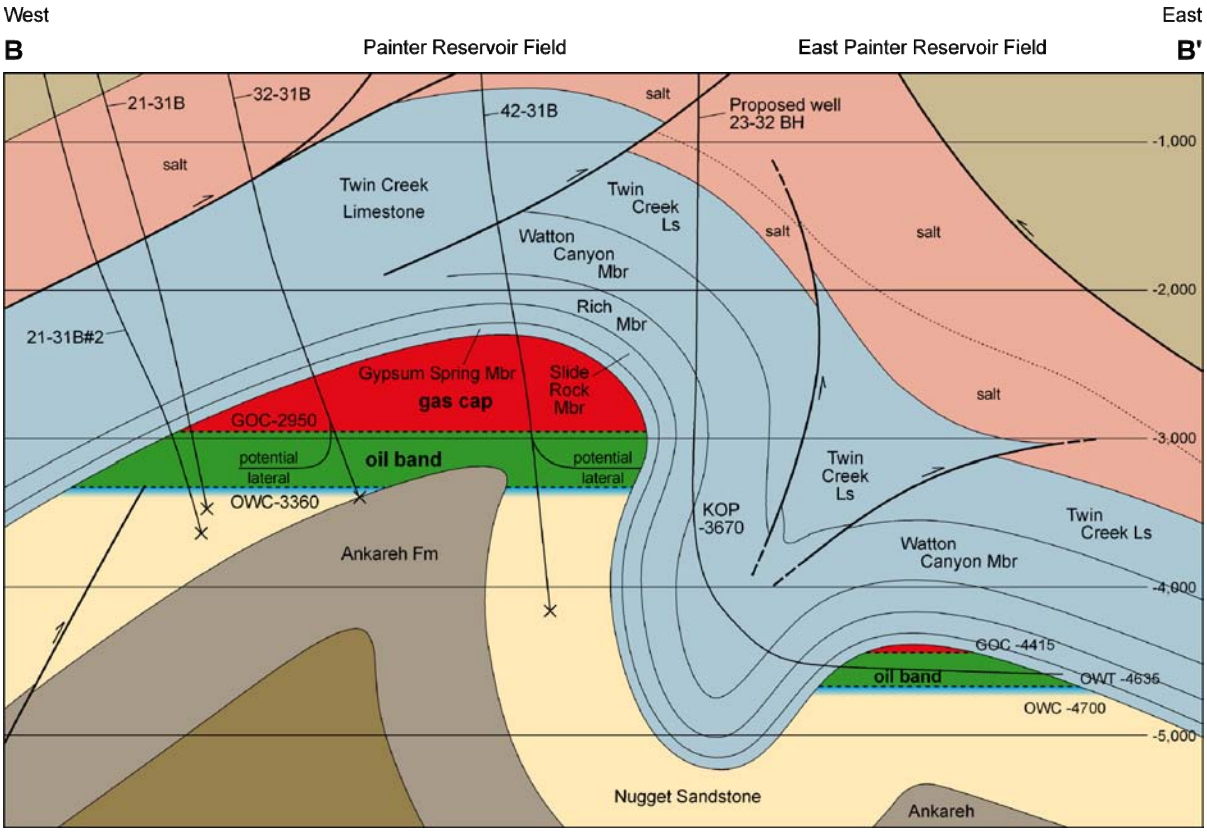


Figure 13-16. East-west structural cross section, showing potential horizontal drilling targets, Painter Reservoir and East Painter Reservoir fields, Uinta County, Wyoming (modified from Wyoming Oil and Gas Conservation Commission, 1998b). Depth in feet, datum = mean sea level.

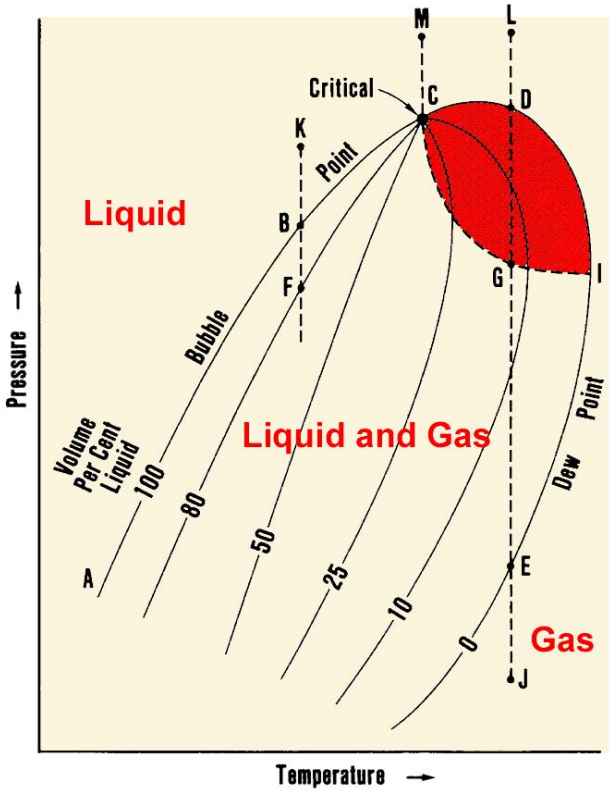


Figure 13-17. Phase diagram for a hydrocarbon mixture. After Katz and others (1959).

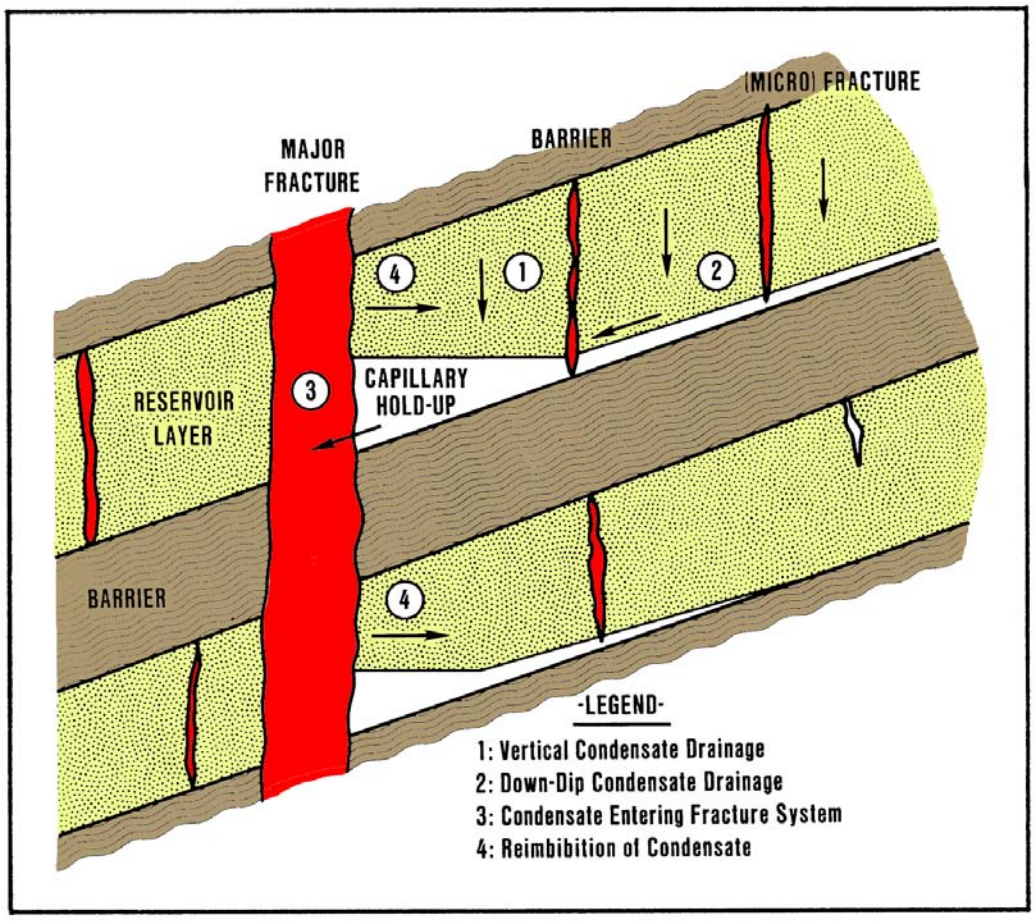


Figure 13-18. Schematic diagram of condensate drainage through fractures. After Castelijns and Hagoort (1984).

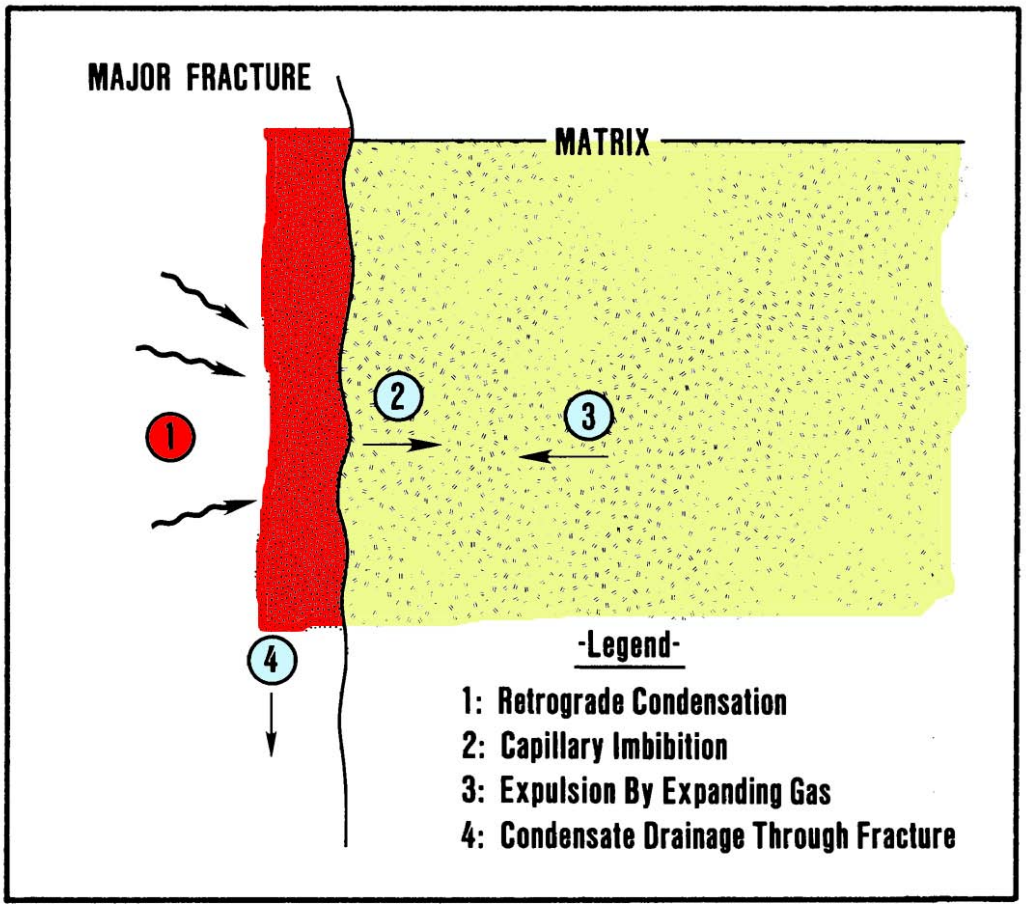


Figure 13-19. Schematic diagram of condensate drainage through matrix. After Castelijns and Hagoort (1984).

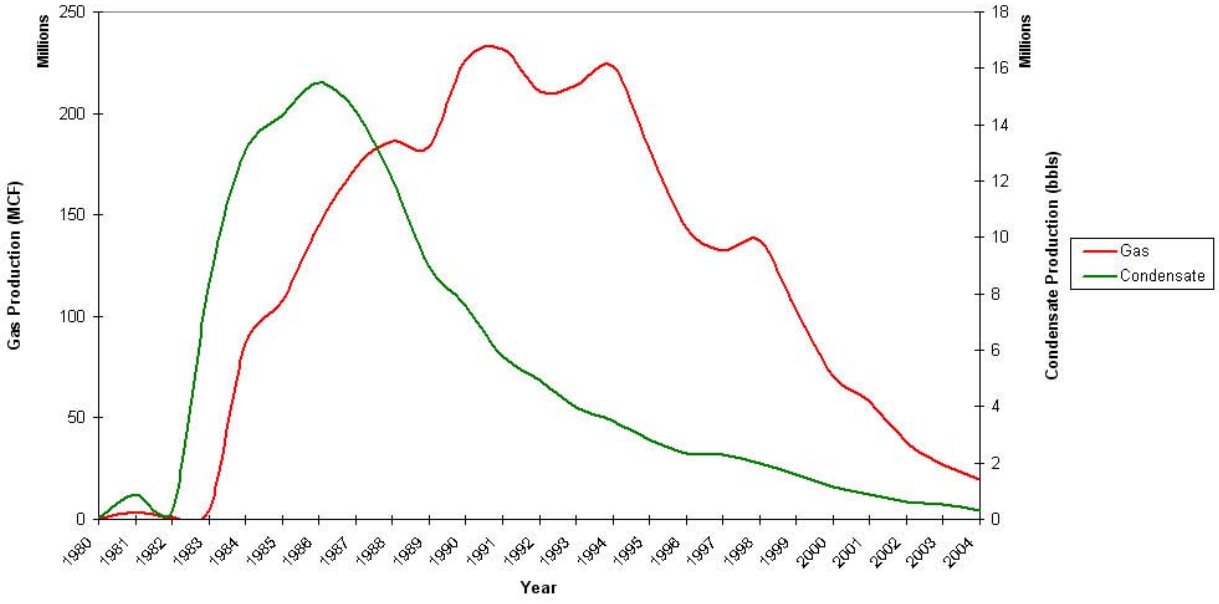


Figure 13-20. Historical production (condensate and gas) for Anschutz Ranch East field. Data from Utah Division of Oil, Gas and Mining production records through January 1, 2005.

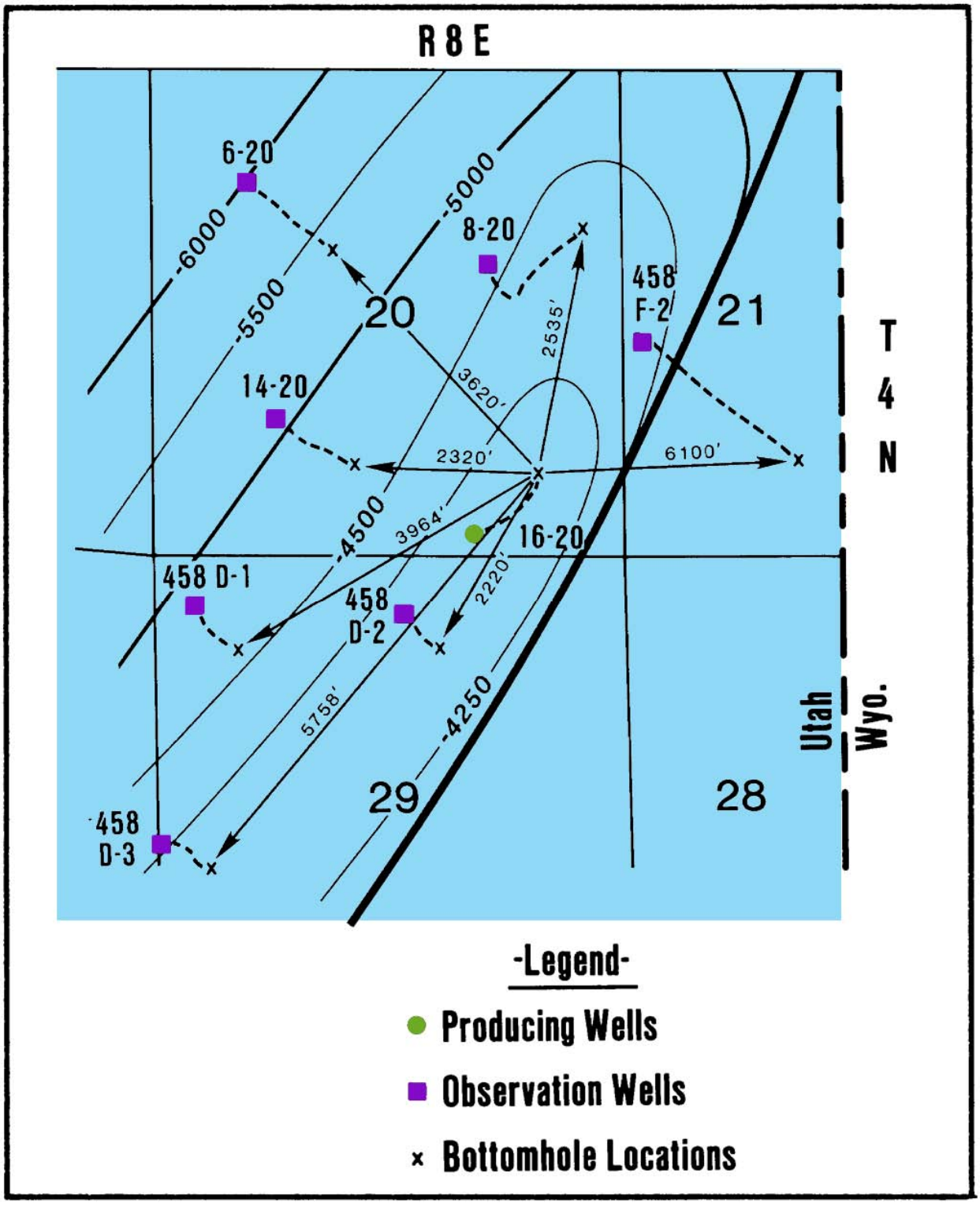


Figure 13-21. Producing and observation wells used in the interference test. After Pollock and Bennett (1986).

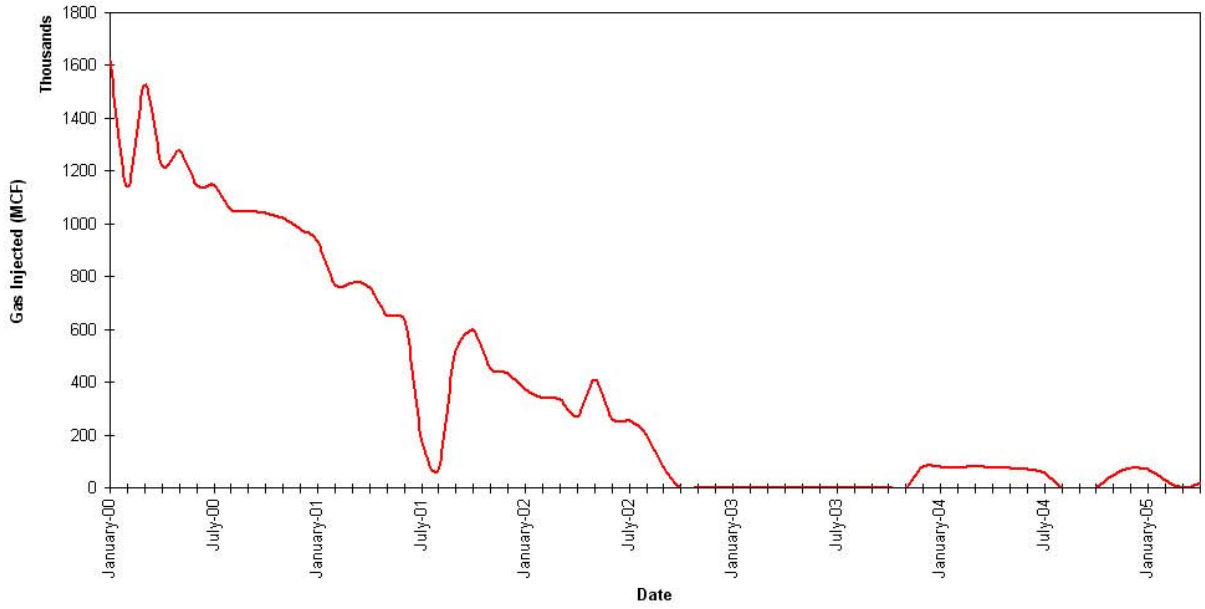


Figure 13-22. Gas injection at Anschutz Ranch East field since 2000. Data from Utah Division of Oil, Gas and Mining production records through January 1, 2005.

Table 13-1. Horizontal well production from the Utah thrust belt as of August 1, 2008. Data from Utah Division of Oil, Gas and Mining production records.

Well	Year Completed	MBO	MMCFG	MBW	Status
Pineview Field					
Bingham 2-6H	1997	57.3	85.6	46.9	POW
UPRC 3-11H	1997	1.1	3.4	58.3	Shut in
Pineview Field Totals		*58.4*	*89.0*	*105.2*	
Lodgepole Field					
Judd 34-1H	1994	235.7	50.4	87.5	POW
UPRR 35-2H	1994	159.7	25.2	115.1	Shut in
UPRC 27-1H	1996	0	0	0	P&A
Blonquist 26-1H	1996	0	0.2	95.0	Shut in
Lodgepole Field Totals		*395.4*	*75.8*	*297.6*	
Elkhorn Ridge Field					
UPRR 19-2 1H	1984	0	0	0	J&A
UPRR 19-2X 1H	1993	574.8	288.0	522.6	Shut in
UPRR 17-2H	1994	267.9	108.0	234.6	POW
Newton Sheep 24-1H	1995	122.2	39.7	396.2	Shut in
Newton Sheep 20-1H	1995	136.9	86.9	131.2	Water Injection Well
Elkhorn Ridge Field Totals		*1101.8*	*522.6*	*1284.6*	
Total Horizontal Production		**1555.6**	**687.4**	**1687.4**	

MBO = 1000 bbls of oil, MMCFG = million cubic feet of gas, MBW = 1000 bbls of water, POW = producing oil well, P&A = plugged and abandoned.

Table 13-2. Evaluation of potential fluids for pressure maintenance. After Kleinsteiber and others (1983).

Fluid	Advantage	Disadvantage
Carbon dioxide	Early gas sales Better recovery than nitrogen	Lack of availability Volume/compressibility Disadvantage Corrosion
Nitrogen	Early gas sales Availability Volume/ compressibility advantage Cost	Large power requirements Causes liquid to dropout in reservoir
Combustion flue gas	Early gas sales Availability Volume/compressibility advantage Smaller power requirements than nitrogen	More expensive than nitrogen Corrosion
Produced hydrocarbon gas	Best availability	Defers gas sales Permits only partial pressure Maintenance
Produced hydrocarbon gas with purchased hydrocarbon make-up	Best recovery	Defers gas sales Possibility of make-up source Interruptions Most expensive

CHAPTER 14 – BEST PRACTICES FOR UINTA BASIN PLAYS, UTAH

by
Craig D. Morgan, and J. Wallace Gwynn,
Utah Geological Survey;
Richard Jarrard, University of Utah;
Richard Curtice, Halliburton Energy Services

Introduction

Over 50 fields have been discovered in the Uinta Basin, Utah (figure 1-2B), with production from 6000-plus wells. Data were collected from the files of the Utah DOGM where there is a wealth of publicly available information, and various publications for selected fields in the basin. This information includes structure maps and cross sections, production and pressure data, completion reports, drilling and development plans, and testimony given at spacing hearings and other hearings before the Utah DOGM. The purpose of this data collection was to help determine the best drilling, completion, and secondary/tertiary recovery techniques for these and similar fields. Specific completion and reservoir management practices were described by various operators of oil fields in Uinta Basin.

Best Practices, Deep Overpressured Continuous and Conventional Northern Uinta Basin Plays

Greater Altamont-Bluebell-Cedar Rim Field Trend Overview

The greater Altamont-Bluebell-Cedar Rim field trend of Duchesne and Uintah Counties, Utah, occurs along a generally contiguous, stratigraphic, updip pinchout on the north-dipping flank of the Uinta Basin near the basin axis (figures 2-13, 6-1, and 7-1). The gentle northern regional dip is occasionally interrupted by subtle structural noses (figure 7-2). Oil production is from multiple, stacked, fluvial-deltaic channel and shoreface storm deposit sandstone, and some lacustrine limestone and shale in the Tertiary upper Green River, lower Green River, and Flagstaff Member (of the Green River Formation/Colton (Wasatch) Formations. The Flagstaff Member/Colton reservoir is an overpressured, basin-centered, oil accumulation controlled by fractures. Typical wells produce from 20 to 50 zones in Altamont and Bluebell reservoirs (Smouse, 1993a). These zones are channel and shoreface sandstones, 3 to 40 feet (1-13 m) thick. The producing Altamont-Bluebell-Cedar Rim field trend extends over a 290,580-acre (117,600-ha) area.

Quartzarenites and litharenites predominate in the north part of the basin. They consist of monocrystalline quartz with chert as the main lithic component (Fouch and others, 1992). Diagenetic effects both reduce and enhance reservoir porosity and permeability. Compaction and authigenic clay formation (illite) have reduced reservoir quality in the Altamont-Bluebell-Cedar Rim field trend (Pitman and others, 1982). Porosity ranges from 2 to 20%, averaging 5%. Permeability is highly variable ranging from 0.1 up to 1000 millidarcies (mD) in fractured zones (Fouch and others, 1992; Smouse, 1993a). The drive is solution gas, and the initial water saturation was 10% or greater (Smouse, 1993a).

The first Green River Formation reservoir was discovered in 1949 at Bluebell field (Roosevelt unit), with the completion of the Humble Oil Ute Tribal No. 1 well, NW1/4SW1/4 section 21, T. 1 S., R. 1 E., Uinta Base Line and Meridian (UBL&M); initial flowing potential was 1633 bbls of oil per day (BOPD) (260 m^3/d). The first Wasatch Formation reservoir was discovered in 1970 at Altamont field, with the completion of the Shell Oil Miles No. 1-36A4 well, SW1/4NE1/4 section 35, T. 1 S., R. 4 E., UBL&M; initial flowing potential was 1004 BOPD (160 m^3/d). The Altamont-Bluebell-Cedar Rim field area currently has 585 producing (or shut-in) wells (Utah Division of Oil, Gas and Mining, 2008). The well spacing is two producing wells per section. Cumulative production as of August 1, 2008, was 284,238,372 bbls of oil (45,939,901 m^3), 481 billion cubic feet of gas (BCFG) (14 BCMG), and over 523 million bbls of water (83 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The original, estimated, primary recovery was 316,000,000 bbls of oil (Smouse, 1993a).

Ownership in the Altamont-Bluebell-Cedar Rim field trend has changed many times since the trend's discovery. In 1999, Devon Energy Corporation purchased Pennz Energy's (formerly Pennzoil) Uinta Basin operations. After assuming ownership of the properties Devon drilled five new wells. Like other operators, Devon found that the second well per section usually had some pressure drainage in some of the beds. This results in marginal to uneconomical wells that only produce about 200,000 bbls (31,800 m^3) of oil. At 2004 prices, a well could be operated at a rate as low as 10 bbls (2 m^3) of oil per day (John Pully, Devon Energy Corporation, verbal communication, 2004).

Devon's new wells were drilled and completed following standard practice for the area. About 10,000 feet (3300 m) of intermediate casing was set near the top of the Wasatch (Colton) Formation before drilling the potentially overpressured, lower productive interval. Perforation intervals were selected based on drilling shows and gamma-ray and resistivity log values. The wells were completed with an acid stimulation in two 800-foot (270 m) stages (approximately) (John Pully, Devon Energy Corporation, verbal communication, 2004).

Optimal Drilling, Development, and Production Practices for the Greater Altamont-Bluebell-Cedar Rim Field Trend

Much of the following data was gathered by Richard Curtice with Halliburton Energy Services as part of the U.S. Department of Energy-funded study of the Bluebell field completed in 1999 and summarized in Morgan (2003b). Many of the operators have changed their completion practices since the completion of the study; most notably the majority of the operators now use a proppant fracture treatment. Although the following discussion may not be accurate for many current practices (2000 to present), it is accurate for most of the producing wells in the field. Individual beds in the lower Green River and Wasatch producing interval of the Altamont-Bluebell-Cedar Rim field trend are difficult to evaluate. Fracturing and complex formation-water chemistries make conventional geophysical log analysis highly questionable. Petroleum economics have discouraged open hole and/or production testing of individual beds. Therefore, operators do not clearly understand which beds in any particular well are potentially significant producers, limited producers, water producers, or thief zones. Other field development issues include communication between zones via vertical fractures, high water cuts, and paraffin buildup; these problems necessitate numerous workovers. In addition, water disposal can be an issue if injection wells are not available near remote well sites.

The individual producing beds are difficult to evaluate because fracturing, clay content,

rugose hole conditions, and poorly constrained formation-water resistivities make conventional geophysical log analysis difficult. Production testing of individual beds in either cased or open hole can be quite costly because of the potentially large number of beds involved, and therefore is typically not done. As a result, wells are completed in a "shotgun" approach by perforating all the beds that had any show of hydrocarbons while drilling, or on the geophysical well logs, or in neighboring wells. The common practice is to perforate numerous beds over thousands of vertical feet and apply an acid-frac treatment, generally 20,000 gallons (75,700 L) of hydrochloric acid (HCl). This treatment is applied to both clastic and carbonate, fractured and non-fractured beds, over-pressured and normally pressured zones. The gross productive interval in many wells is over 3000 feet (900 m) thick. During the life of a well, new perforations are often added, increasing the net footage treated (Morgan, 2003b). Recently many of the operators have begun treating wells using a proppant fracture stimulation.

Many operators have begun treating older wells by staging the acid treatments over intervals of about 500 feet (150 m) per stage, and by using much more diverting agent than in the past. This method ensures that the acid is pumped in the perforated beds more effectively and results in fewer perforated beds being bypassed (Reid and others, 1995). Unfortunately, this technique still represents a relatively indiscriminate approach and results in acidizing many beds that may be nonproductive, water productive, or thief zones. Typically, an operator treating a 1500-foot (500-m) interval will treat the lower 500 feet (160 m), move the packer up and treat the middle 500 feet (152 m), and then treat the upper 500-foot (160-m) interval. Ideally, the diversion material plugs the perforations of a stage before moving up hole so only 500-foot (160-m) sections are being treated at a time. To improve completion techniques in the Altamont-Bluebell-Cedar Rim field trend it is necessary to accurately identify productive beds and reduce the number of beds requiring stimulation (Morgan, 2003b). Formation imaging, oil indicator, and fracture identificant logs can all improve the reservoir characterization.

HCl is the most common treatment fluid used in the field trend but proppant fracture treatments are being used more often. Corrosion inhibitors, surfactants, and iron, scale, and clay control additives are commonly used in most, but not all, treatments. The use of diverters is important when trying to treat large intervals so that the fluids flow into as many of the perforated beds as possible. When acid begins to enter a perforation, the flow carries the diverter into the perforation, plugging it off and causing the acid to flow to other perforations. When the acid flows back out of the hole, the diverting agent should come out of the perforation and flow back with the acid. The most commonly used diverters in the Bluebell field are rubber-coated-nylon (RCN) ball sealers and benzoic acid flakes. Rock salt, wax beads, and mothballs have all been used as diverters. Common practice is to use more than one type of diverter in a single treatment (Morgan, 2003b).

Devon Energy generally picks new beds to perforate based on drilling shows and favorable gamma ray and resistivity values. They stimulate the new beds with 15% HCl plus additives using about 100 gallons (390 L) per foot, using a pumping rate of 5 to 8 bbls (1-2 m^3) per minute at a maximum of 9000 psi (62,000 kpa). Sand proppant is occasionally used when treating shallower sandstone beds (typically 9000 feet [3000 m] or less), but hadn't been used in the past on the deeper beds due to the higher pressures, which would crush the sand proppant (John Pully, Devon Energy Corporation, verbal communication, 2004). Synthetic proppant agents that withstand the high pressure are very expensive, but operators feel the proppant improves well performance enough to justify the added cost.

The following sections summarize the findings of a UGS project titled *Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field, Uinta Basin, Utah* conducted from 1994 to 1998, funded under the DOE Class I Oil Program (Allison and Morgan, 1996; Morgan, 1997; Deo and Morgan, 1998; and Morgan and Deo, 1999). As part of the study, Halliburton Energy Services Tech Team in Denver, Colorado, analyzed Bluebell field treatment data and completion histories from 67 wells consisting of 246 stimulations (108 different parameters in each treatment). The treatments were performed between August 1968 and November 1994. The total depths (TD) of the wells analyzed varied from 12,314 to 17,419 feet (3753-5309 m). The analysis determined which types of casing and perforating techniques have been used, which types of stimulation treatments have been pumped, which types have been the most effective, and what additives have been used and their effectiveness. The project also included field demonstrations of the recommended techniques in Bluebell field (Morgan, 2003b).

Log analyses: Quantitative log analysis is normally the primary method for identifying lithology, porosity, and water saturation of individual beds in order to select the best zones to perforate. However, in Altamont-Bluebell-Cedar Rim field trend, quantitative log analysis is seldom undertaken, for several reasons: (1) poor hole conditions leading to poor-quality logs, (2) inability of standard logs to identify open fractures, and (3) inaccurate water resistivities leading to poor estimates of water saturation.

The reliability of log-based estimation of percent shale (percent clay), porosity, and water saturation was evaluated, using core plugs and cuttings for ground truth (Allison and Morgan, 1996). The analyses showed (1) log-based determination of percent shale is relatively straightforward (although determination of the non-shale component is non-unique), (2) clean-formation porosity is best determined using an average of neutron and density porosity, and (3) uncertainties in fluid resistivity preclude accurate calculation of water saturation.

Based on core-plug analyses, it was determined that sufficient intergranular permeability for long-term producibility will be found only among nearly shale-free rocks that have porosities greater than 6%. Gamma-ray logs are only a moderately good indicator of shale-free rocks; spectral-gamma logs are substantially better. Neutron/density porosity averaging can indicate zones with adequate porosity, but only if rugose hole conditions do not excessively degrade log accuracy and if shaly zones are avoided. Of the many beds typically chosen for completion in an Altamont-Bluebell-Cedar Rim field well, a large number appear to be promising based on overly optimistic porosity determinations, but will have only transient production. Increased attention to two factors, (1) shale-free beds and (2) reliably determined high porosities, will significantly increase the average producibility of zones chosen for completion.

Log-based porosity can be calculated from any of the four standard logs: (1) density, (2) neutron, (3) sonic, or (4) resistivity. For example, in Bluebell field, industry practice is to calculate porosity either by simple averaging of neutron and density porosities or by converting sonic travel time to porosity. The former is preferred if hole conditions are good enough to permit satisfactory neutron and density logging. In unusually rugose holes, a sonic log is run instead to provide porosities.

Uncertainties in fluid resistivity preclude accurate calculations of water saturation; measurements and calculations of the water resistivity are highly variable. The median R_W in the Roosevelt Unit area of Bluebell field is 0.74 ohm·meter at 68°F (20°C) and no systematic variation is evident with depth, except for temperature-dependent variations.

Casing designs: Typically, three strings of pipe are set in a deep well drilled in the Altamont-Bluebell-Cedar Rim field trend. The first string is a 9-5/8-inch (24.4 cm) diameter surface pipe, or in some cases 10-3/4-inch (27.3 cm) diameter. The second, intermediate string of pipe is 7- or 7-5/8-inch- (17.8 or 19.4 cm) diameter pipe set from a depth of 9,450 to 13,982 feet (2880-4262 m). The third string is commonly a 5-inch- (12.7 cm) diameter liner weighing 18 pounds per foot (lb/ft [26.8 kg/m]). Occasionally, some 5-1/2-inch- (13.9 cm) and a few 4-1/2-inch- (11.4 cm) diameter strings are set. Typically the depth of the liner is from 12,314 to 17,419 feet (3753-5309 m) and the length varies from 1859 to 5314 feet (567-1620 m). Not all of the wells have liners; seven wells, or 10.4% of the wells studied, have no indication that a liner was set.

Perforations: The perforated interval is often quite large. The reported net interval (total footage perforated) varies from 4 to 1310 feet (1.2-399 m), and the gross perforated interval (depth of the lowest perforation minus the depth of the top perforation) varies from 4 to 3009 feet (1.2-917 m). The number of perforations ranges from four shots to a maximum of 5240 shots. Perforations vary in size from 0.26 to 0.56 inch (0.66-1.42 cm) diameter, the most common being 0.38 inch (0.97 cm) diameter. The density of the perforations varies from one to four shots per foot, the most common being two shots per foot. The depth to the top perforation varies from 8195 to 15,450 feet (2498-4709 m) and the depth to the bottom perforation varies from 9656 to 16,417 feet (2943-5004 m). The average gross perforated interval has the top perforation at 11,350 feet (3460 m) and the bottom perforation at 12,539 feet (3822 m), or an overall average gross perforated interval of 1190 feet (363 m) with 284 perforations. Common practice is to perforate every potentially productive interval at the same time. Historically, the trend has gone from producing a small interval to a larger interval, from a few perforations to many perforations, and from small to large acid treatments. However, improvement in well response over time is questionable (Morgan, 2003b).

Stimulation fluid treatment: HCl is the most common treatment fluid used (90%) in the Altamont-Bluebell-Cedar Rim field trend (Morgan, 2003b). Most HCl acid treatments had concentrations of 15% acid. The other acid treatments also included HCl acid in part. Ninety-eight percent of the treatments studied were pumped using some type of acid, while the remaining 2% were proppant treatments. The three proppant treatments tried included the following fluid types: (1) borate cross-linked fluid pumped in the lower Green River reservoir with 100,000 pounds (45,360 kg) of 20/40 mesh sand, (2) gelled oil pumped in the Colton/Flagstaff reservoir with only 2000 pounds (907 kg) of sand and 2000 pounds (907 kg) of glass beads, and (3) oil and water emulsion pumped in the lower Green River reservoir with 24,000 pounds (10,886 kg) of 40/60 mesh sand and 76,000 pounds (34,473 kg) of 20/40 mesh sand. The pumping of acid is still the preferred treatment. However, the response to acid treatments typically decreases over time as the well becomes oil depleted. In the late 1960s, for every gallon (3.8 L) of acid pumped, approximately 10 bbls (1.6 m^3) of incremental oil was produced, while the current result is now less than one bbl (0.2 m^3) of incremental oil for every gallon (3.8 L) of acid pumped (Morgan, 2003b). Beginning in the early 2000s most operators began using a proppant fracture treatment.

Acid additives – When a formation is treated with acid to increase production, there is a large arsenal of chemical additives which help to enhance oil production. Typically an acid treatment will contain, at a minimum, the following types of additives: (1) surfactants, (2) corrosion

inhibitor, (3) iron control, and (4) some type of clay control. Other additives are available but have a more specific application depending on the problem. There are ten different additive types used which can be categorized according to their effects.

Not all the additive types are used in all treatments, but it is surprising that certain additives were not used on all of the treatments. For instance, corrosion inhibitor is one chemical additive that one would expect to find in all the acid treatments. The primary purpose of corrosion inhibitor is to protect tubular goods and surface equipment from being damaged by acid. Without this additive it is quite possible to damage some tubing or casing in the wellbore, yet this additive was only used in less than half the treatments.

Surfactants are commonly found in most acid systems, but again only a little over half the treatments have used some type of surfactant. The primary use of surfactants is to reduce the surface tension of a liquid to allow it to flow easier and prevent emulsions from forming. They also are used to change the wettability of a formation. The type of surfactants available to the industry has increased over the years, but in some cases the same surfactant package that was used in 1968 is still being used today. However, the data show the surfactant had little to no effect on post-treatment production. Generally, this additive should be left out unless other types and concentrations of surfactant prove to perform better in the future.

Iron control is the second most commonly used additive (used in half the treatments). Formation damage due to iron precipitation has been recognized as a significant problem in wellbores for over 30 years, yet is often ignored. Pyrite, a source of iron in the Green River Formation, was identified in several core samples taken from wells in Bluebell field. However, the most common source of iron is the tubulars in the wellbore. The wellbore tubulars are a constant source of iron, yet operators apparently never take the prudent action of pickling tubulars prior to acidizing. Millscale on new pipe also contains a large amount of iron. One study on millscale which was conducted in new 2-7/8-inch-diameter (7-cm), 6.5 pound/foot (9.7 kg/m) tubing indicated that a minimum of 690 gallons (2610 L) of 15% HCl acid could react with millscale in 10,000 feet (3300 m) of tubing. If the iron stayed in solution, the acid would contain 81,360 parts per million (ppm) of total iron. The iron that is present in wellbore tubulars typically is just common rust, but this can severely damage the formation when mobilized during an acid treatment. Ignoring this problem while conducting repeated treatments could damage a formation beyond repair.

Clay control additives are also used in about a third of the treatments. Clay control additives, in proper concentration, can prevent swelling and/or migration of clay particles. The most common clays in the Green River Formation are illite-smectite and chlorite-smectite mixed-layered clays, and a minor amount of kaolinite (Allison and Morgan, 1996). Therefore, use of a good clay control additive is recommended when treating the Green River.

Friction reducers are used to reduce the friction pressure loss caused by pumping down small tubulars at high rates. Friction reducers can help maintain the desired pump rate to treat the formation or reduce the number of high-pressure pumps needed. In Bluebell field, the average depth of the tubing is 10,812 feet (3300 m). The rates at which fluids are pumped down 2-7/8-inch-diameter (7-cm) tubing varied from 0.3 bbl per minute (BPM) to 19.5 BPM (0.05-3.1 m^3/min). The overall average pumping rate down 2-7/8-inch-diameter (7-cm) tubing is 9.2 BPM (1.5 m^3/min). To obtain rates much over 8 BPM (1.3 m^3/min) it is necessary to use some type of friction reducer.

Friction reducers in the treating fluids also help mitigate friction pressure loss to allow use of decreased well-head-treating pressure (WHTP). Decreased WHTP lowers the hydraulic

horsepower (HHP) needed for increased pumping rates. Although friction reducers do not enhance the acid system, they do affect the placement of the treatment. If acid is pumped at 9 BPM (1.26 MTM) and no friction reducer is used in the acid, the friction pressure loss alone for the average depth of 2-7/8-inch-diameter (7-cm) tubing would be equal to 5400 psi (37,200 kPa). If the acid contained a gelling-agent friction reducer, the friction pressure loss for the same string of tubing would only be 1520 psi (10,480 kPa). By using a gelled acid instead of a non-gelled acid the WHTP would be reduced by 3880 psi (26,750 kPa) at 9 BPM (1.4 m^3/min) and the HHP requirement would also be reduced by 856.

Silt suspenders and foaming agents have been used in some treatments. In a few cases the foaming agent appeared in the surfactant category because this additive fits both categories. This type of additive is typically used if a foamed fluid is desired, or if removal of fines is a problem. For instance, if a sandstone is held together by calcium carbonate cement, then the acid will remove the cement and the rock basically falls apart leaving behind fines that will plug pore throats. If plugging of pore throats by fines is a problem, then either this type of additive should be used, or the acid should contain a gelling agent that will maintain enough viscosity in the treatment fluids to carry fines out of the formation during treatment cleanup.

Nitrogen (N_2) and carbon dioxide (CO_2) are not chemical additives, but are common gases used in the treatments. The use of a gas in a treatment does several things: (1) enhances treatment cleanup, (2) increases the volume of the treatment, and (3) in the case of N_2, decreases the hydrostatic pressure during the treatment. One of the advantages of using a gas assist is that well cleanup is faster and sometimes more thorough. A foaming agent is often used in gas-assist treatments resulting in a foamed fluid, which helps in removing fines generated from the acid treatment. One of the disadvantages of using a gas is that it is compressible, making it difficult to determine what type of diverter action is taking place. Gas-assist treatments have not resulted in a significantly better well response compared to the typical acid treatment.

Paraffin buildup is a problem in the Altamont-Bluebell-Cedar Rim field trend and throughout the Uinta Basin, yet only a limited number of treatments have used some type of solvent or paraffin control in the acid system. When solvents were used, the volumes were so small (100 to 1000 gallons [375-3785 L]) that they were probably not effective. When a solvent was used, it was spearheaded in front of all the other fluids and probably only affected one interval, and few active ingredients were left by the time it passed the first perforations.

Acid can only react with a material if it contacts it. Scale is a problem throughout the field trend and is typically layered with paraffin (scale then paraffin or paraffin then scale, similar to rings found in a tree trunk). When an acid, without some type of solvent, comes in contact with layered scale, the chances of reacting with more than one layer of scale is questionable. An acid containing a solvent will remove layers of both scale and paraffin.

Treatment fluids are usually heated prior to being pumped down the hole. This is a good practice and should be continued. Heating the fluids helps prevent paraffin from solidifying and plugging the porosity in the formation. However, only the water phase of the acid is heated and the heat loss when cooler acid is added to the water can be quite substantial. The temperature of the acid solution is typically high enough to prevent solidification of paraffin, but may not be high enough to dissolve paraffin layers in the scaling.

Diverters – Good diversion (diverting the treatment fluid into all of the perforations) is needed when attempting to treat large intervals. There have been several types of diverters used in Altamont-Bluebell-Cedar Rim treatments. The most commonly used diverter is 7/8-inch (2 cm)

diameter, RCN, ball sealers with a specific gravity (SG) of 1.1 or 1.3, except in older treatments where 1.4 SG balls were used. The number of balls pumped ranged from 7 to 3000 for a single treatment. The percentage amount of excess ([number of holes/number of ball sealers] * 100) ranges from 13 to 389%, with an average of 160%. Ball sealers provide excellent diversion when enough fluid and high-enough flow allow the balls to seat in the perforations. Typically, the balls are slugged or given such a small fluid volume it is difficult to get a good seal. Balls were run in both the acid system and spacers as the diverter fluid. Perforations must also be in fairly good shape for balls to seal properly; if there is severe corrosion or pipe deterioration, the efficiency of the ball sealer will decrease. A minimum of 50 gallons (190 L) of fluid should be used per ball sealer whether the ball sealer is placed in the acid or the spacer fluid. A minimum pumping rate of 5 to 8 BPM (0.8-1.3 m^3/min) should provide adequate velocity to seat the balls; fluid viscosity can also help with ball action. The SG of the balls should be very close to, or equal to, the fluid density (as possible) in which the ball sealer is placed. This will increase the seating efficiency of the ball sealer.

Benzoic acid flakes are the second most commonly used diverting agent in the treatments studied. The advantages of benzoic acid flakes are: (1) they are soluble in water, acid, and oil, and (2) they will also sublime in gas wells. Some of the disadvantages are: (1) they do not form as strong a bridge as other diverting material, (2) they cost more than other diverting materials, (3) they will not bridge 3/8-inch- (1 cm) diameter perforations or a slot having a width greater than 0.13 inches (0.3 cm), (4) the material will not dissolve without adequate fluid flow, and (5) high concentrations of acid flakes can also cause erratic pump rates because they have a tendency to settle out underneath pump valves. Concentrations of benzoic acid in the treatments range from 0.25 to 10 pounds/gallon (0.03-1.19 kg/L). Most treatments have concentrations from 0.1 to 1 pound/gallon (0.01-0.12 kg/L) with the majority of the treatments having a concentration of 0.25 to 0.5 pound/gallon (0.03-0.06 kg/L). Total volume of flakes used in a treatment ranged from 200 to 20,000 pounds (90-9100 kg). The fluids used to carry the benzoic acid flakes were acid or a spacer fluid. Recommended concentrations are from 0.5 to 2 pounds/gallon (0.06-0.24 kg/L) in the carrier fluid.

Salt is the third most commonly used diverting agent in the treatments. Salt used for diversion comes in two forms: (1) rock salt which is very coarse in size from 2/8 to 8/12 mesh, and (2) graded salt which ranges in size from 0.003 to 0.25 inch (0.01-0.64 cm). Laboratory tests indicate that the graded salt forms a more effective bridging material than the coarser graded salt. However, both are effective in forming temporary seals. Advantages of salt are: (1) low cost compared to almost all water-based, gelled, carrier fluids, (2) readily soluble in aqueous fluids, and (3) can be used in both oil and gas wells that have some water production. The disadvantages of salt are: (1) it is not compatible with hydrofluoric acid, (2) it must be used in high concentration due to its solubility in water, (3) it will not degrade in oil, and (4) it is not recommended for use at temperatures above 180°F (82.3°C), due to its solubility in water. The salt concentration used ranged from 0.25 to 10 pounds/gallon (0.03-1.19 kg/L) with an overall average of 4 pounds/gallon (0.48 kg/L). Recommended concentrations of salt range from 1 to 5 pounds/gallon (0.12-0.59 kg/L) depending on brine concentration of the fluid. Laboratory tests indicate that graded salt will bridge on a 3/8-inch-diameter (1-cm) perforation or a slot having a width of 0.32 inches (0.8 cm). The carrier fluid should be a high concentration of brine, preferably saturated brine water; if not the salt will go into solution. Gelling the carrier fluid will help suspend the salt particles and carry them through perforations to bridge on fractures.

Wax beads have been used in some treatments. The advantages of wax beads are: (1) they are soluble in oil but not in water, (2) they can be used in temperatures from 80° to 185°F (26.7-84.9°C) (the melting point of wax beads depends on the type of bead used), and (3) wax beads can be used in both oil and gas wells that produce condensate. The disadvantages of wax beads are: (1) their low melting point can lead to agglomeration problems, and (2) they should not be used in wells which produce no liquid hydrocarbons. Treatment concentrations for wax beads have not been reported, but total volumes range from 400 to 20,000 pounds (180-9100 kg). Particle sizes range from 0.07 to 0.23 inch (0.2-0.6 cm) depending on the type of wax bead used. The fluids used as carriers in the treatments are both acid and spacer, but most are pumped in acid. Recommended concentrations are 0.5 to 2 pounds/gallon (0.06-0.24 kg/L) in a gelled carrier fluid.

Moth balls are another diverter used in the treatments. The advantages of moth balls are: (1) they are soluble in oil and condensate, (2) they will bridge on a 3/8-inch-diameter (1-cm) perforation or a slot which is up to 0.24 inch (0.6 cm) in width, (3) they can support a differential pressure up to 1000 psi (6900 kPa), (4) they can be used in fluids up to 176°F (79.9°C) (their melting point), (5) they are compatible with most water-based fluids, and (6) they help reduce paraffin buildup. The disadvantages of moth balls are: (1) they should be pumped in a viscous, gelled fluid due to their high density, and (2) they should not be used in disposal or injection wells. Graded particle sizes ranged from 0.002 to 0.25 inch (0.01-0.6 cm). Recommended concentrations are 1/2 to 2 pounds/gallon (0.06-0.24 kg/L) in a gelled carrier fluid.

Spacers are another type of fluid commonly used to carry diverting agents. The most frequently used fluids for spacing are (1) water-based fluid, commonly brine when rock salt is used, (2) formation water, and (3) 2% potassium-chloride (KCl) water. The advantage of spacers is their excellent ability to carry a diverting agent when large quantities of diverters are to be run. Formation water should be avoided as a carrier or a displacement fluid because the high content of bicarbonates within it neutralizes the acid. The reaction generates CO_2 which can gas lock the centrifugal pump that feeds the high-pressure pumps, resulting in erratic pump rates, and in some cases affecting the placement of the treatment.

More than one type of diverter is frequently used in the Altamont-Bluebell-Cedar Rim treatments. It is common to find at least two, or as many as three different types of diverter used. Diverter action is variable, ranging from excellent to none.

Fracture gradients – Fracture gradients (pressure gradients needed to fracture the rock) are calculated from the instant shut-in pressure (ISIP) which is recorded immediately after pumping has stopped. The ISIP is then used to determine the bottom-hole treating pressure (BHTP). The fracture gradients in Bluebell field treatments range from less than 0.44 up to 1.24 psi/foot (3.03-8.55 kPa/m) with an average of 0.76 psi/foot (5.24 kPa/m). The BHTP needed to treat the bottom perforation can range from less than 5520 to 15,550 psi (38,060 kPa), with an average of 9530 psi (65,710 kPa). This wide variation in fracture gradients results in a wide range of anticipated WHTP. A WHTP of 3940 psi (27,170 kPa) is needed to overcome the average fracture gradient (ignoring friction). If gelled acid is pumped down a typical string of 2-7/8-inch-diameter (7-cm) tubing, the WHTP would be approximately 5460 psi (37,650 kPa) at 9 BPM (1.4 m^3/min). Without a good friction reducer the WHTP would be approximately 9260 psi (63,850 kPa) at 9 BPM (1.4m^3/min), but the BHTP would be the same in both cases.

Scale – Calcium-carbonate scaling is an oil-production-related problem within the Altamont-Bluebell-Cedar Rim field trend. Excessive scaling results in reduced production rates, equipment failure, costly down time, and increased production costs. Calcium carbonate ($CaCO_3$) is the most common and abundant scale type; other scale types (discussed briefly above) include iron sulfide (FeS), acid insolubles, and paraffin. The purpose of scale inhibitors is to prevent, or slow, the process of mineral scale build up. Scale inhibitors were used in about a third of the treatments in the field trend. Scale inhibitors should be used in any wellbore where scaling is a known problem. There are a large number of scale inhibitors, varying by type and activity level, on the market today. Typically, the activity level will vary from 15 to 30% depending on the type of scale inhibitor.

Waters with high percentages of calcium and bicarbonate, high pH, low CO_2 partial pressure, high salinity, and high temperatures favor the formation of $CaCO_3$ scale. The co-production of Green River Formation and Wasatch Formation waters increases the amount of scale that forms, above that which is produced from Wasatch water alone. Scale inhibitors, such as phosphonates, are commonly used. Other potential scale-mitigating measures include the maintenance of high hydrostatic and CO_2 partial pressures, maintenance of low pH in power-water supplies through the addition of small amounts of HCl, or acetic acid, and maintenance of the lowest possible operating temperatures.

While little can be done with the basic chemistry of the brine that is produced by a given well, some actions can be taken to minimize $CaCO_3$ scaling during production. Three ways to reduce scale are as follows:

1. With the addition of small amounts of an acid to the hydro-pump power-water supply, the pH of the water moving through the pump and up the well can be lowered, thus reducing the amount of scale that is formed. Weak acids, like acetic or citric, are less corrosive than a strong acid like HCl.

2. By maintaining a high hydrostatic pressure at the level of the pump and the perforations, the partial pressure of CO_2 (a minor component of the mostly methane gas in this area) might be held and help to prevent scaling. Devising a method of increasing the CO_2 content of the hydro-pump power water, or installing a low-level CO_2 injection system, might have a scale-reducing effect as well.

3. As increased equilibrium temperatures favor the precipitation of greater amounts of $CaCO_3$, maintaining the production system at as low a temperature as possible may help to minimize scaling. Temperatures must, of course, be sustained high enough to prevent hydrocarbon solidification.

Scale and wax buildup continue to be common production problems. However, Devon does not use paraffin inhibitors because they are difficult to extract from the crude at the refinery. They do use some scale inhibitors, squeezing the scale inhibitors into the formation, if scale buildup is a serious problem. Devon cleans up the wellbore by giving it a hot oil treatment about once a month. A heat string in the well allows the pumping of hot oil down the wellbore without pulling the production string (John Pully, Devon Energy Corporation, verbal communication, 2004).

High-rate hydraulic fracture treatments – High-rate hydraulic fracture treatments are a viable option that has been overlooked as a completion technique in this field and should be considered on newer wells. If higher rates are desired, pumping the treating fluid down the casing instead of the tubulars should be considered.

Production treatment correlations – No clear correlations can be made between hydrocarbon production and type and size of treatment. However, it appears that the acid treatments are understimulating the wells as shown by the limited amount of time the wells are in linear flow. Surprisingly, no correlation could be made between the amount of acid pumped and the size of the interval being treated. Moderate-sized acid treatments seem to be as economical as large acid treatments. This appears to be independent of the interval being treated. Most wells in the area have been treated more than once. Typically, the first and second treatments yield the best results (fairly effective for up to four to five months), the third and forth treatments are generally not as effective, but were also usually smaller in size. Why the later treatments in the same interval are not as effective is not known. This could indicate damage to the formation is not being removed, or that the beds are depleted. The volume of the treatment does not appear to be a major factor. Treatments which range from 20,000 to 30,000 gallons (75,700-113,600 L) seem to be slightly more effective, but apparently, the most critical acid treatment is the first one. If additional acid treatments are pumped they should be the same size as the first treatment.

Higher pumping rates and well-head treating pressures appeared to make better wells also. The higher pressures caused by higher pumping rates could be an indication of good diversion taking place, allowing more of the treatment to go into more of the formation. However, higher pumping rates that just increase the WHTP are not necessary. Pumping rates from 8 to 12 BPM (1.3-1.9 m^3/min) are adequate to carry diverters, and maintain a reasonable WHTP.

Dual-burst thermal-decay time and dipole-shear anisotropy logs: The use of the dual-burst, thermal-decay time (TDT) and dipole-shear anisotropy (anisotropy) logs are effective in identifying potentially oil-productive beds in new and older wells in the greater Altamont-Bluebell-Cedar Rim field trend. The data from these logs can help select the most productive beds and reduce the number of beds perforated as well as reduce potential water production. The TDT logs indicate the presence of hydrocarbons and may also show the amount of depletion in beds, including those not perforated, which implies vertical communication in the reservoir. The anisotropy log indicates open fractures. A tracer log is used to show if the acid treatment went above or below perforations in some beds, utilizing fractures indicated on the anisotropy log.

In combination, these logs increase the understanding of acid treatment effectiveness. For example, communication above and below test intervals is a major problem in the region. Old wells especially have numerous perforations that have had conventional acid treatments (typically a 500- to 1500-foot [150-460 m] interval) several times, increasing the potential for communication behind the casing. Much of the acid may move vertically through the cement and not into the formation.

Fractured reservoirs represent another problem. Completion test results from a UGS/DOE funded Bluebell field demonstration project (Morgan and Deo, 1999; Morgan, 2003b) generally confirmed the interpretation of the anisotropy and TDT logs. Beds with fractures indicated in the anisotropy log generally took most of the acid, while beds without fractures took

little to no acid. The low treating pressure (about 7000 psi [48,000 kPa] versus the normal treating pressure of 10,000 psi [69,000 kPa]) was not high enough to hydraulically induce new fractures.

High-paraffin crude: The crude oil produced from the Tertiary Green River and Wasatch (Colton) Formations is high in paraffin wax. As a result, the pour point of the oil is typically 90 to 120°F (32-49°C). Produced oil is stored on location in insulated tanks and the production facilities have a heat treater that keeps the oil above the pour-point temperature (figure 14-1). The oil is trucked from the field to refineries in Salt Lake City (John Pully, Devon Energy Corporation, verbal communication, 2004).

Pumps: Three types of pumps are commonly used in the Altamont-Bluebell-Cedar Rim field trend (figure14-2): (1) the standard pump jack, both center and rear gearbox, (2) the submersible pump, and (3) the rotary-flex pump. The submersible pumps are hydraulically operated by pumping water down the well bore and are often used when the well is producing a high volume of water. The rotary-flex pump is more expensive, but provides a long, slow stroke resulting in less torque on the gearbox and less wear on the production rods. Production rods in both the standard and rotary-flex pumps typically last 10 years and some have lasted up to 20 years or more (John Pully, Devon Energy Corporation, verbal communication, 2004).

Water production and disposal: The Altamont-Bluebell-Cedar Rim is a mature field trend and water production is a significant part of the operating costs. A particular bed or zone in a well may start to make a large volume of water. Devon currently produces about 21,000 bbls (3300 m^3) of oil a day and 9000 bbls (1430 m^3) of water per day. Devon rarely cement squeezes the perforations. Cement squeezes can present mechanical difficulties in an older well with numerous perforations, often resulting in a costly operation that may not successfully stop the water production. The most common method of shutting off a water zone is to use an isolation assembly. This consists of an upper and lower packer with tubing through the assembly which isolates the zone but allows fluid flow through the assembly (John Pully, Devon Energy Corporation, verbal communication, 2004).

Disposal of produced brine from oil wells is a significant concern in the Uinta Basin. In 2003, nearly 47 million bbs (7.5 million m^3) of brine were produced from oil and gas wells in Duchesne and Uintah Counties. Low-cost water disposal is essential to economically producing and extending the life of these mature wells and increasing the number of new wells. A few oil well producers have injection wells to dispose of some of their produced brine, but most do not and are dependent on commercial disposal facilities (Chris Denver, Water Disposal Inc., verbal communication, 2004). Devon has a water gathering system with four water injection wells. They are able to dispose of 90% of their produced water representing a significant cost savings. Their water disposal costs using injection wells are about 35 cents per barrel, while trucking the water to a commercial disposal site costs about 85 cents per barrel (John Pully, Devon Energy Corporation, verbal communication, 2004).

There are four and five commercial disposal facilities in Duchesne and Uintah Counties, respectively (figure 14-3). Produced brine is disposed of by evaporation in ponds (figure 14-4A) or injection into saltwater aquifers. For many years Water Disposal Inc. operated three evaporation ponds about 5 miles (8 km) north of the center of the town of Roosevelt (figure 14-4A). The ponds were installed in 1989 and received brine from operators throughout the Uinta

Basin. An abandoned oil well near the disposal facility was converted to an injection well, and brine from the ponds along with newly received brine is injected into the Green River Formation at a depth of about 9800 feet (3300 m). The facility currently receives 2000 to 3000 bbls (300-500 m^3) per day of new brine (Chris Denver, Water Disposal Inc., verbal communication, 2004).

The disposal facility is using a three-phase centrifuge to recover oil from reclaimed ponds and from brine that it receives and tank bottoms. Fluid, sludge, and contaminated soil from the bottom of the ponds are processed through the centrifuge extracting high-quality oil, brine (which is disposed down the injection well), and a small amount of solids (Chris Denver, Water Disposal Inc., verbal communication, 2004).

A truck load of brine typically contains about 2% oil. Brine from a truck is pumped into one of three cement flats (figure 14-4B). The oily sludge is skimmed off the top and sent to the centrifuge where brine, solids, and oil are separated (figure 14-4C). The brine from the centrifuge and the remaining brine in the flats are sent to storage tanks to be injected down the well. The centrifuge has been a successful technique in reclaiming the evaporation ponds (figure 14-4D) and extracting high-quality oil from the produced brine and tank bottoms that is lost during the typical disposal process (Chris Denver, Water Disposal Inc., verbal communication, 2004).

Low-volume gas wells: There are currently three, shallow, low-volume gas wells producing from the top of the Green River/base of the Uinta Formation. All of the production goes through a gas plant designed to separate associated gas from the oil production. The volume of gas is below what is needed to efficiently run the plant. As a result, producers do not get full value for the gas. Additional shallow gas wells will probably not result in a large enough volume for the gas plant; therefore, it is not economical to drill new shallow gas wells in the area (John Pully, Devon Energy Corporation, verbal communication, 2004).

Environmental issues: Production sites and facilities are well established and there are few environmental issues. Surface test pits were all reclaimed in the 1990s. Fluids from testing and recompletion operations now go into metal pit tanks and then are disposed. Screen cones are placed on the heat treater stacks to prevent birds from getting into the stacks and becoming injured (figure 14-5).

The most significant problem is the expanding population in the area. Homes and cabins are being built in the area and surface owners without mineral rights do not appreciate oil operations on their property (John Pully, Devon Energy Corporation, verbal communication, 2004). Residential expansion near the Roosevelt disposal facility resulted in conflicts between homeowners and the disposal facility because of the occasional smell from the ponds. In a settlement with Roosevelt City, those disposal ponds are being drained and the surfaces reclaimed (Chris Denver, Water Disposal Inc., verbal communication, 2004).

Red Wash-Wonsits Valley Fields Overview

Red Wash field: Red Wash field, Uintah County, Utah, is a stratigraphic pinch-out across a structural nose (figures 7-1 and 7-3) that produces primarily from fluvial-deltaic and shoreface storm/wave sandstone in the Douglas Creek Member of the Green River Formation (Castle, 1990). The net reservoir thickness is 170 feet (50 m), which extends over a 31,000-acre (12,500-ha) area. Porosity ranges from 10 to 22%, along with an average of 42 mD of permeability (Schuh, 1993a).

Red Wash field was discovered in 1951 with the completion of the California Oil Co. (Chevron) Red Wash Unit No. 1 well, NE1/4NE1/4 section 26, T. 7 S., R. 23 E., Salt Lake Base Line and Meridian (SLBL&M); initial flowing potential was 339 BOPD (54 m^3) and 698 MCFGPD (20 MCMPD). The field currently has 193 producing (or shut-in) wells. The well spacing is 40 to 80 acres (16-32 ha). The present reservoir field pressure ranges from 400 to 2000 psi (2800-13,800 kpa).

Cumulative production as of August 1, 2008, was 80,791,477 bbls of oil (12,845,845 m^3), 341.5 BCFG (9.7 BCMG), and over 310 million bbls of water (50 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The original estimated primary recovery was 53 million bbls of oil (8.4 million m^3) and 300 BCFG (8.5 BCMG) (Schuh, 1993a). The estimated secondary recovery was 53 million bbls of oil (8.4 million m^3) using a waterflood program (Schuh, 1993a).

Wonsits Valley field: Wonsits Valley field, Uintah County, Utah, is a stratigraphic trap due to lateral facies changes (figure 14-6) that produces from medium-grained, quartz sandstone and fine-grained, sandy, ostracodal limestone deposited in a high-energy, barrier-beach complex of the Douglas Creek Member (Castle, 1990). The net reservoir thickness is 90 feet (30 m), which extends over a 6240-acre (2530-ha) area. Porosity and permeability averages 12% and 22 mD, respectively (Schuh, 1993b).

Wonsits Valley field was discovered in 1962 with the completion of the Gulf Oil Co. Stout Federal Unit No. 1 well, NE1/4NE1/4 section 8, T. 8 S., R. 22 E., SLBL&M; initial flowing potential was 13 BOPD (2 m^3) and 8 bbls of water per day (1 m^3). The field currently has 245 producing (or shut-in) wells. The well spacing is 40 acres (16 ha). The present reservoir field pressure is 2500 psi (17,200 kpa).

Cumulative production as of January 1, 2008, was 48,367,595 bbls of oil (7,690,448 m^3), 64 BCFG (2 BCMG), and over 169 million bbls of water (27 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The original estimated primary recovery was 21.6 million bbls of oil (3.4 million m^3) (Schuh, 1993b). The estimated secondary recovery was 26.4 million bbls of oil (4.2 million m^3) using a waterflood program similar to Red Wash field (Schuh, 1993b).

Optimal Drilling, Development, and Production Practices for the Red Wash-Wonsits Valley Fields

To enhance production and the ultimate recovery from the waterflood units in Red Wash and Wonsits Valley fields, the following completion and reservoir management practices are now being employed by the current operator (Russ Griffin, Questar Exploration and Production Co., verbal communication, 2003).

Digital database: All geophysical well logs are converted into digital form allowing extensive mapping, correlating, and construction of cross sections with minimal effort. Well histories for all the wells were entered into a database allowing rapid access and review of decades of activity in any well.

Manage well stimulation fracture treatments: Common practice in the past was to apply massive or large fracture treatments as part of a well completion program. Large fracture treatments have resulted in vertical communication between zones greatly reducing the effectiveness of the flood. Fracture treatments are now generally much smaller. The fracture

treatments are designed to ensure that the induced fractures do not extend vertically out of the intended zone especially if the well is going to be an injector.

Oil fingerprinting and water sampling: Oil samples are collected and fingerprinted from each producing zone. Most wells are producing from multiple zones; each zone will flood at a different rate. With fingerprinting, a sample collected at the wellhead can be used to determine the percentage of production contributed by each zone without pulling tubing and running production logs. If a zone is contributing nothing, then that zone is probably flooded and can be cemented off. Water samples are also collected from individual zones to determine the chemical characteristics and resistivity. For the waterflood programs, the operator uses fresh water from the Green River in the new areas of the fields and produced water in the older sections.

Biannual injectivity surveys: Spinner surveys are run twice a year in the injection wells to determine which zones the water is entering.

Reservoir mapping: Each producing zone is mapped (structure and isopach) including oil and water production. By monitoring the oil and water contribution from each zone and plotting these data on the maps, the operator can see the advance of the waterfront for each zone and identify areas that may be by-passed by the flood.

Spacing: Originally, part of Red Wash field was completed on 40-acre (16-ha) spacing. There is an east-to-west permeability trend through the field that is related to the regional fracture trends. The early operators experienced rapid water breakthrough in many of the wells during the waterflood program with 40-acre (16-ha) spacing. An 80-acre (32-ha) spacing works best at Red Wash; many of the wells in the 40-acre (16-ha) spaced area have been plugged, increasing the spacing between wells.

Best Practices, Conventional Southern Uinta Basin Play

Monument Butte Field Overview

Monument Butte field (figures 8-1 and 8-2), Duchesne County, Utah, is the most significant field in the Conventional Southern Uinta Basin play in terms of production, wells, and secondary recovery programs, and will therefore be discussed in detail in this section. The field is a stratigraphic updip pinchout along the gentle north-dipping flank of the Uinta Basin (figure 14-7) that produces from stacked, fluvial-deltaic channel and shoreface wave/storm sandstones in the middle and lower Green River Formation (Lomax, 1993). The net reservoir thickness is 16 feet (5 m), which extends over a 21,000-acre (8500-ha) area. Porosity and permeability ranges from 10 to 20% and 25-30 mD, respectively. The drive is solution gas and the initial water saturation was 30 to 35% (Lomax, 1993).

Monument Butte field was discovered in 1981, with the completion of the Lomax Exploration Company Monument Butte Federal No. 1-35 well, SE1/4SE1/4 section 25, T. 8 S., R. 16 E., SLBL&M; initial flowing potential was 37 BOPD (6 m^3/d) and 19 MCFGPD (0.5 MCMPD). The field currently has 456 producing (or shut-in) wells (Utah Division of Oil, Gas and Mining, 2008). The well spacing is 40 acres (16 ha). The original reservoir field pressure was 2150 psi (14,800 kPa); the present reservoir field pressure ranges from 600 to 1800 psi (4100-12,400 kPa) (Lomax, 1993).

Cumulative production as of January 1, 2008, was 22,030,880 bbls of oil (3,502,909 m^3), 64 BCFG (1.8 BCMG), and over 5 million bbls of water (0.8 million m^3) (Utah Division of Oil, Gas and Mining, 2008). The original estimated primary recovery was 5% of the original oil in place (OOIP). With multiple waterflood projects the secondary recovery is expected to be 15 to 25% of the OOIP (Lomax, 1993).

Optimal Drilling, Development, and Production Practices for Monument Butte Field

Much of the following information is based on discussions with Michael Guinn, engineer with Inland Production Company, in 2003. The field was purchased by Newfield Exploration Company in 2004. Mr. Guinn is now employed by Newfield and continues most of the practices discussed below.

Drilling wells: Development drilling in the greater Monument Butte area is relatively easy. Wells are typically drilled to a total depth of 6000 to 6500 feet (2000-2200 m) in the middle and lower Green River Formation. Most wells take about six days to drill. Inland Production Company (Inland) currently (2003) operates about 750 wells and expects to drill 1200 more wells on 40-acre spacing over the next 20 years (60 wells per year). The development program has a very high success rate with approximately one well in 60 being plugged and abandoned during a year. Surface casing is set at about 300 feet (100 m) as per state requirement, and then the well is drilled to a total depth with a freshwater mud system. There are no high-pressure zones or significant lost circulation problems, even in the small, lenticular sandstone reservoirs. Eagle Services, a subsidiary of Inland, owns a drilling/workover rig and employs the drill crews. Having their own rig ensures availability when they need it and costs less than contracting (Michael Guinn, Inland Production Co., verbal communication, 2003).

Completing wells: The geophysical logging suite consists of: (1) gamma ray; (2) density and neutron porosity; and (3) resistivity. Mud-logging units were originally used while drilling, but are no longer required. Sandstone beds with more than 8% neutron porosity are selected for perforating with 40 shots per foot. The gross perforated interval can be as long as 2000 feet (700 m). Each bed, or closely spaced group of beds, are stimulated separately, resulting in four to five, but occasionally as many as nine, sand fracture treatments per well. The stimulation includes about 2500 to 4000 pounds (1100-1800 kg) of sand/perforated foot with an average of 80,000 pounds (36,000 kg) of sand per well. The typical treatment is pumped at a pressure of 1800 to 2000 psi (12,000-14,000 kPa) with a maximum of 4200 psi (29,000 kPa). The lowermost perforated bed or interval is treated first, then a composite bridge plug is set above the bed and the next bed is treated and a composite bridge plug is set above it. This procedure continues up the hole until all the perforated beds have been treated. The fracture fluids are then flowed back to the surface. The composite bridge plugs allow flow up the hole but not down. Most wells can be treated in a day.

Inland has their own frac (or holding) tanks, reducing the cost of the fracture treatments. Inland builds the battery (separator, lines, and storage tanks) before treating the well. As a result, the well can be placed on production as soon as the completion rig moves off location. Placing the well on production immediately ensures that the fracture treatment fluids that did not flow back are not left in the hole for an extended period where they can cause formation damage (Michael Guinn, Inland Production Co., verbal communication, 2003).

Producing wells and waterflood projects: All completed wells are placed on primary production using artificial lift. The original reservoir pressure is near the bubble point pressure of the oil, therefore, the wells are converted relatively soon to secondary waterflooding to maintain reservoir pressure above bubble point, maximizing recovery. The waterflood uses an alternating injector – producer pattern on 40-acre (16-ha) spacing. The size of waterflood units in the greater Monument Butte area varies, but most are about 1 to 2 square miles (3-5 km^2) with 16 wells per section (a section is 1 square mile [2.6 km^2]). There are 1320 feet (440 m) between wells with one well drilled in the center of each 40-acre (16-ha) tract. A well that is scheduled to be an injector will be produced until the production rate drops to about 15 BOPD (2 m^3/d) and then is converted to injection. Most wells are on primary production for 1.5 years. Injection water is a combination of produced and culinary water with corrosion and scale inhibitors added. Currently, Inland is injecting about 3000 barrels of produced water/day (500 m^3/d) and 18,000 barrels (3000 m^3/d) of culinary water/day from Starvation Reservoir, about 18 miles (29 km) to the northwest. Typical injection pressure is from 1400 to 2000 psi (9700-14,000 kPa). The Inland waterflood program is in a relatively early stage and significant breakthrough of injected water has not occurred. As a result, the flood is monitored by well production rates, but there are no regular isolation tests conducted to monitor the flood at the bed scale (Michael Guinn, Inland Production Co., verbal communication, 2003).

In 2006 a pilot program was begun drilling several wells at 20-acre (8-ha) spacing. The infill wells successfully tapped banked oil, found new pay, and improved sweep efficiency (Morgan, 2008). The 20-acre spacing program will increase the recovery and accelerate recovery from the Monument Butte waterflood. Infill drilling could result in 1000 additional locations and extend the drilling to 30 years at current levels. Tertiary oil recovery techniques, such as gas flooding, have not been tested in the Monument Butte field but could significantly increase recovery and extend the life of the field if proven to be successful (Morgan, 2008).

There are over 20 secondary recovery units in Monument Butte field. Three of these units (the Travis, Monument Butte Northeast, and Beluga) are discussed in the following sections.

Travis waterflood unit – The Travis waterflood unit covers the southern half of section 28 and the northern half of section 33, T. 8 S., R. 16 E., SLBL&M (figures 14-7 and 14-8). The major reservoirs in the Travis unit are sandstone beds of the Travis interval that were deposited in cut-and-fill valleys on a gently northeast-dipping structure (figures 14-8 and 14-9). Secondary objectives are sandstone beds in the Castle Peak, Monument Butte, and Beluga intervals described in detail by Morgan and others (1999, 2003) and Morgan and Bereskin (2003). Thickness of the Travis sandstone can vary from more than 100 feet (30 m) to near zero in a neighboring well only 1320 feet (400 m) away (figures 14-8 and 14-9). In areas where cut-and-fill did not occur, less-productive marginal-lacustrine sandstone beds were deposited.

The Travis waterflood unit included nine active injection wells during 2002. The average daily injection of fresh/produced water was 444 barrels (71 m^3) at an average injection pressure of 1505 psi (10,380 kPa) (Utah Division of Oil, Gas and Mining, 2002). Water injection has increased oil production only moderately (figure 14-10). The complex internal heterogeneity of the Travis reservoir, such as turbidite channel, debris flow, and gravity-flow deposits, may result in poor injection efficiency and poor pressure communication between injector and producer wells (inadequate sweep efficiency).

Monument Butte Northeast waterflood unit – The Monument Butte Northeast waterflood unit covers all of section 25, and parts of sections 24 and 26, T. 8 S., R. 16 E., SLBL&M (figures 14-7 and 14-11). The Monument Butte reservoir consists of amalgamated, stacked, channel-sandstone deposits on a gently northeast-dipping structure (figure 14-11 and 14-12). The MGR 7b bed (described by Morgan and others, 1999, 2003; and Morgan and Bereskin, 2003) is responsible for about 70% of the oil production from the Monument Butte Northeast unit (figure 14-12). However, there are 27 other beds that have been perforated in one or more wells in the unit (figure 14-12). Secondary objectives are sandstone beds in the Castle Peak, Travis, and Beluga intervals. Most wells are perforated in the Monument Butte reservoir, also known as the Douglas Creek B, C, and D sands (Morgan and Bereskin, 2003), which is the primary objective.

The Monument Butte Northeast waterflood unit included 11 active injection wells during 2002. The average daily injection of fresh/produced water was 651 barrels (104 m^3) at an average injection pressure of 1339 psi (9232 kKa) (Utah Division of Oil, Gas and Mining, 2002). Initial water injection increased oil production significantly (figure 14-13). Eventually, as water injection occurred, the reservoir pressure was raised above the bubble point as indicated by the reduction in the gas-to-oil ratio.

Beluga waterflood unit – The Beluga waterflood unit covers the southern half of sections 7 and 8, and all of sections 17 and 18, T. 9 S., R. 17 E., SLBL&M (figures 14-7 and 14-14). In the Beluga unit, the Monument Butte reservoir is the primary productive interval, but most wells in the unit also produce from sandstone beds in the MGR 13 log-cycle of the Beluga interval (described by Morgan and others, 1999, 2003; and Morgan and Bereskin, 2003). The Beluga reservoir consists of lenticular channel sandstone beds on a gently north- to northeast-dipping structure (figures 14-14 and 14-15).

The Beluga waterflood unit included 15 active injection wells during 2002. The average daily injection of fresh/produced water was 806 barrels (104 m^3) at an average injection pressure of 1791 psi (12,350 kPa) (Utah Division of Oil, Gas and Mining, 2002). After 15 months, water injection increased oil production significantly (figure 14-16). Once injection began, the reservoir pressure was raised above the bubble point as indicated by the reduction in the gas-to-oil ratio.

Recompleting wells: The original completion technique involved selecting beds to be perforated in each well based on the well logs, but without regard for plans for the longer-term waterflood. As a result, some producing wells were perforated in beds that were not perforated in the injection wells, and some injection wells were perforated in beds that were not open in the neighboring producing wells. During 2003, Inland recompleted the producing wells, perforating all beds that are productive in the waterflood unit. In 2004, Inland plans to recomplete the injection wells and perforate all beds that are productive within the unit (Michael Guinn, Inland Production Co., verbal communication, 2003).

Environmental issues: The greater Monument Butte field area has several environmental issues, such as mountain plovers and raptor nests, which cannot be avoided. A field operator should hire people who can work closely with the regulatory agencies involved. In order to keep crews and rigs busy and ensure the development program is progressing, it is important to have several drilling options available so if environmental issues delay some plans there are still other activities that can be pursued.

Inland and other operators in the Uinta Basin have expressed concern over a conflict of

interest that can arise in dealing with wildlife issues. For example, while studying raptors in an area, an operator along with Utah Division of Wildlife Resources personnel might work to improve the habitat, such as building artificial raptor nests, but if the work is successful and more raptors are attracted to the area, then the operator's activity near those nests can be greatly restricted (Michael Guinn, Inland Production Co., verbal communication, 2003).

The increased footprint that a 20-acre (8-ha) infill program would cause was a major concern. As a result, the 20-acre infill wells were drilled from existing drill pads. Newfield has begun consolidating production facilities which, will ultimately greatly reduce the footprint and visual impact of the field.



Figure 14-1. Insulated tanks and heat treater at the Ute Fee 2-33C6 well in Cedar Rim field, SW1/4SW1/4 section 33, T. 3 S., R. 6 W., UBL&M.

A



B



C

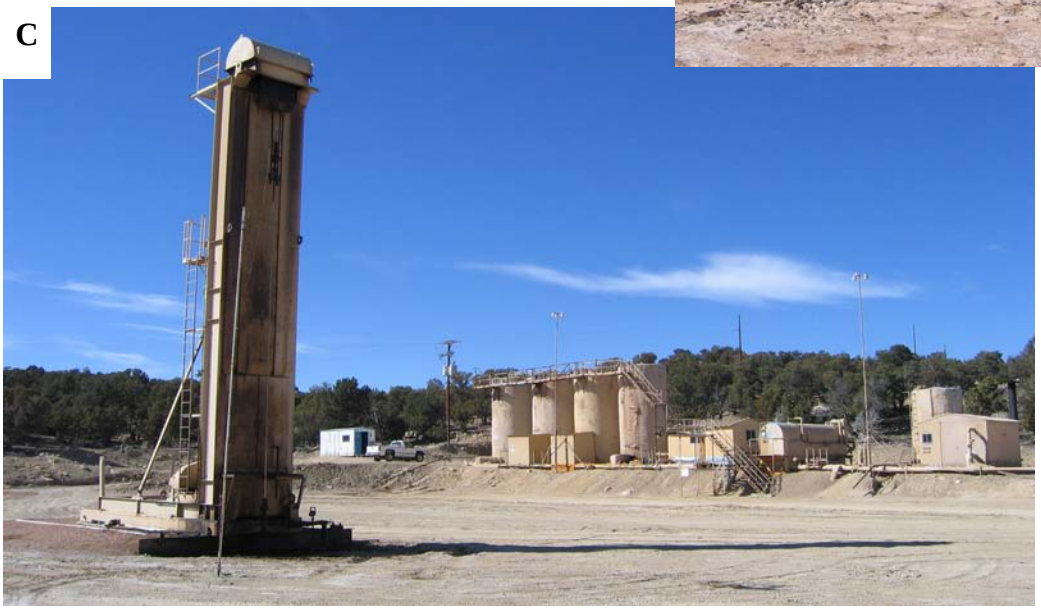


Figure 14-2. Several types of pumps are commonly used in the greater Altamont-Bluebell-Cedar Rim field trend. A - Standard pump jack, Devon Energy Corporation Bar-F-2-5B1, SW1/4SE1/4 section 5, T. 2 S., R. 1 W., UBL&M. The well was completed March 1991 and has produced 186,133 BO, 183,946 MCFG, and 102,610 BW. B - Submersible pump, Quinex Energy Corporation Malnar Pike 1-17A1E, SW1/4SW1/4 section 17, T. 1 S., R. 1 E., UBL&M. The well was completed April 1987 and has produced 164,521 BO, 135,749 MCFG, and 225,663 BW. C - Rotary flex pump, El Paso Production Oil and Gas Company Ute Fee 2-33C6, SW1/4SW1/4 section 33, T. 3 S., R. 6 W., UBL&M. The well was completed December 1985 and has produced 893,161 BO, 881,599 MCFG, and 1,330,771 BW. All production data are from the Utah Division of Oil, Gas and Mining, 2008.

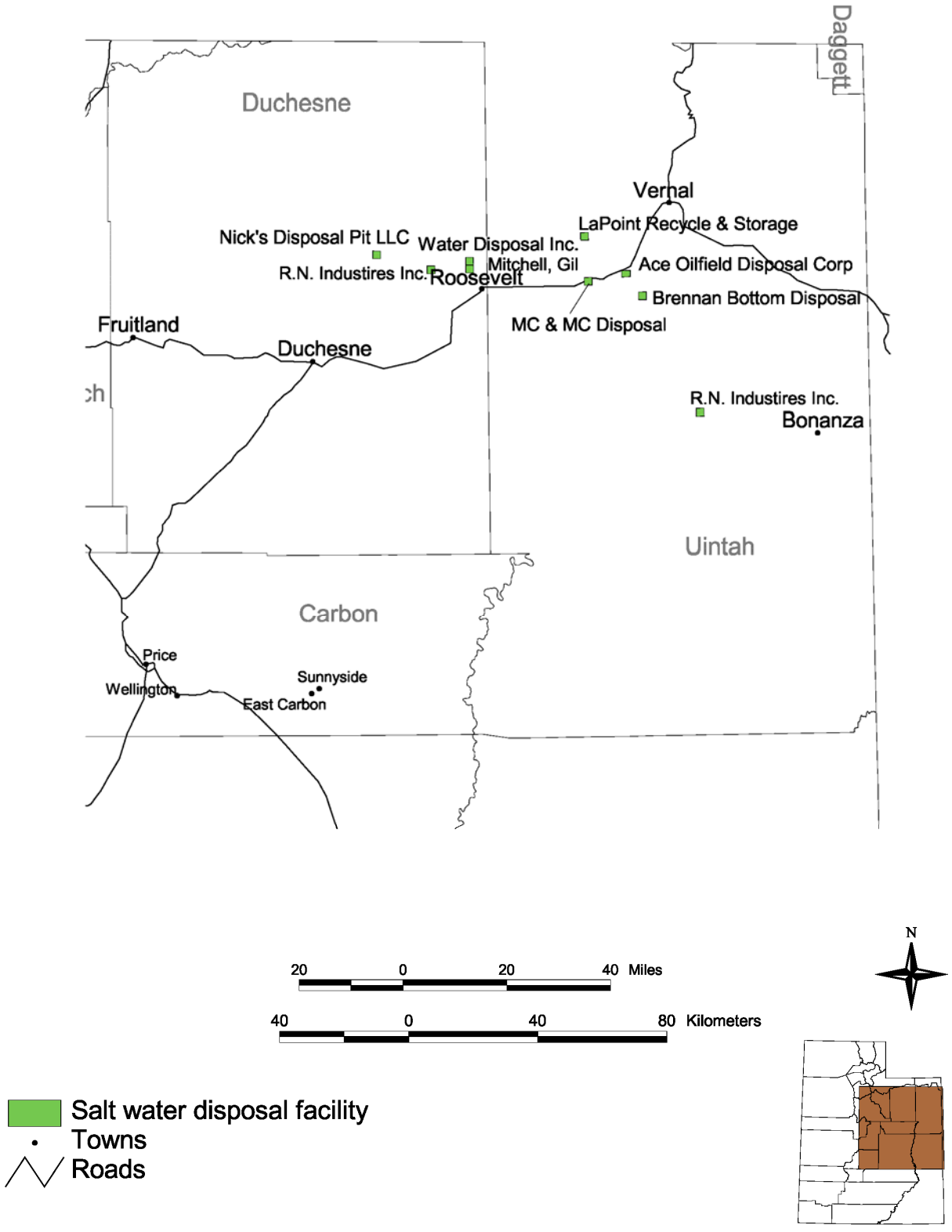


Figure 14-3. Location of commercial water disposal facilities used by oil-field operators in the Uinta Basin.

A



B



C



D



Figure 14-4. Commercial water disposal facility, used by Altamont-Bluebell-Cedar Rim field operators, near the town of Roosevelt. A - Brine evaporation ponds. B - Cement flats where oily sludge is skimmed off the top and sent to a centrifuge. C - Where brine, solids, and oil are separated. D - Reclamation of an evaporation pond.



Figure 14-5. Heat treater with bird screen on the exhaust stack at the El Paso Production Oil and Gas Company Ute Fee 2-33C6, SW1/4SW1/4 section 33, T. 3 S., R. 6 W., UBL&M, in Cedar Rim field.

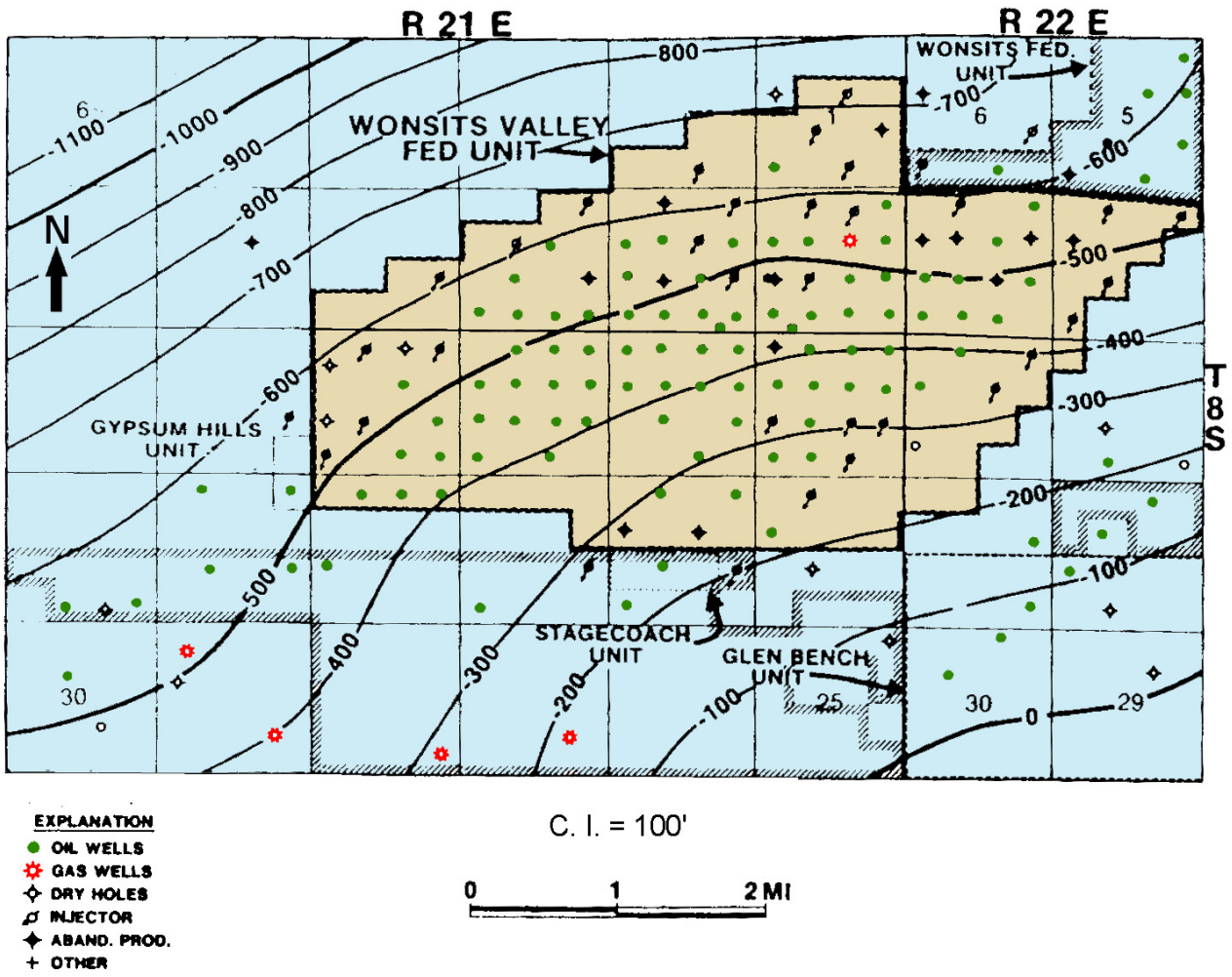


Figure 14-6. Structure map on top of G1 producing zone of the Green River Formation, Wonsits Valley field, Uintah County, Utah (after Schuh, 1993b).

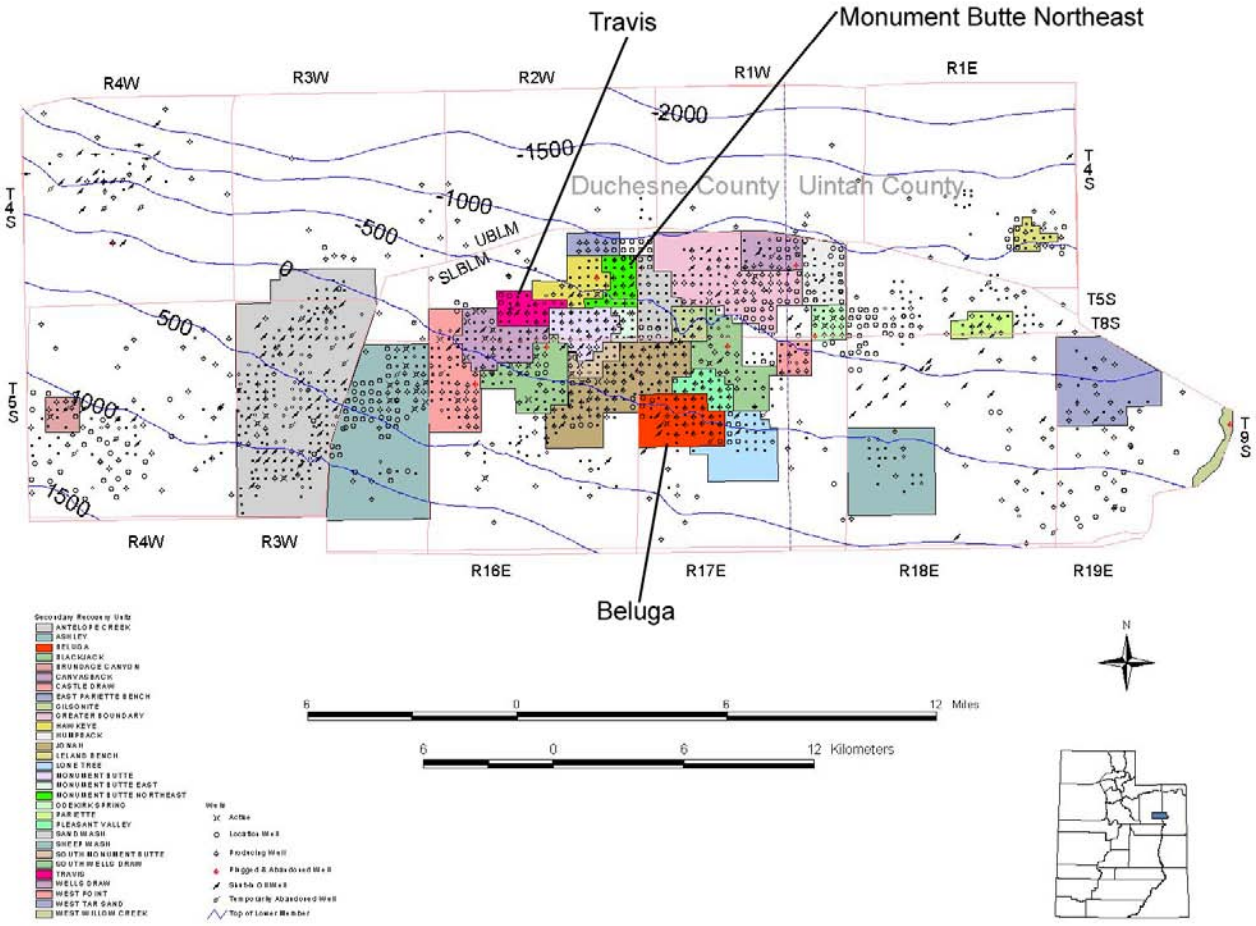


Figure 14-7. Structure map on top of the lower member of the Green River Formation, greater Monument Butte field area, Duchesne and Uintah Counties, Utah. Secondary recovery units are also shown. Contour interval = 500 feet.

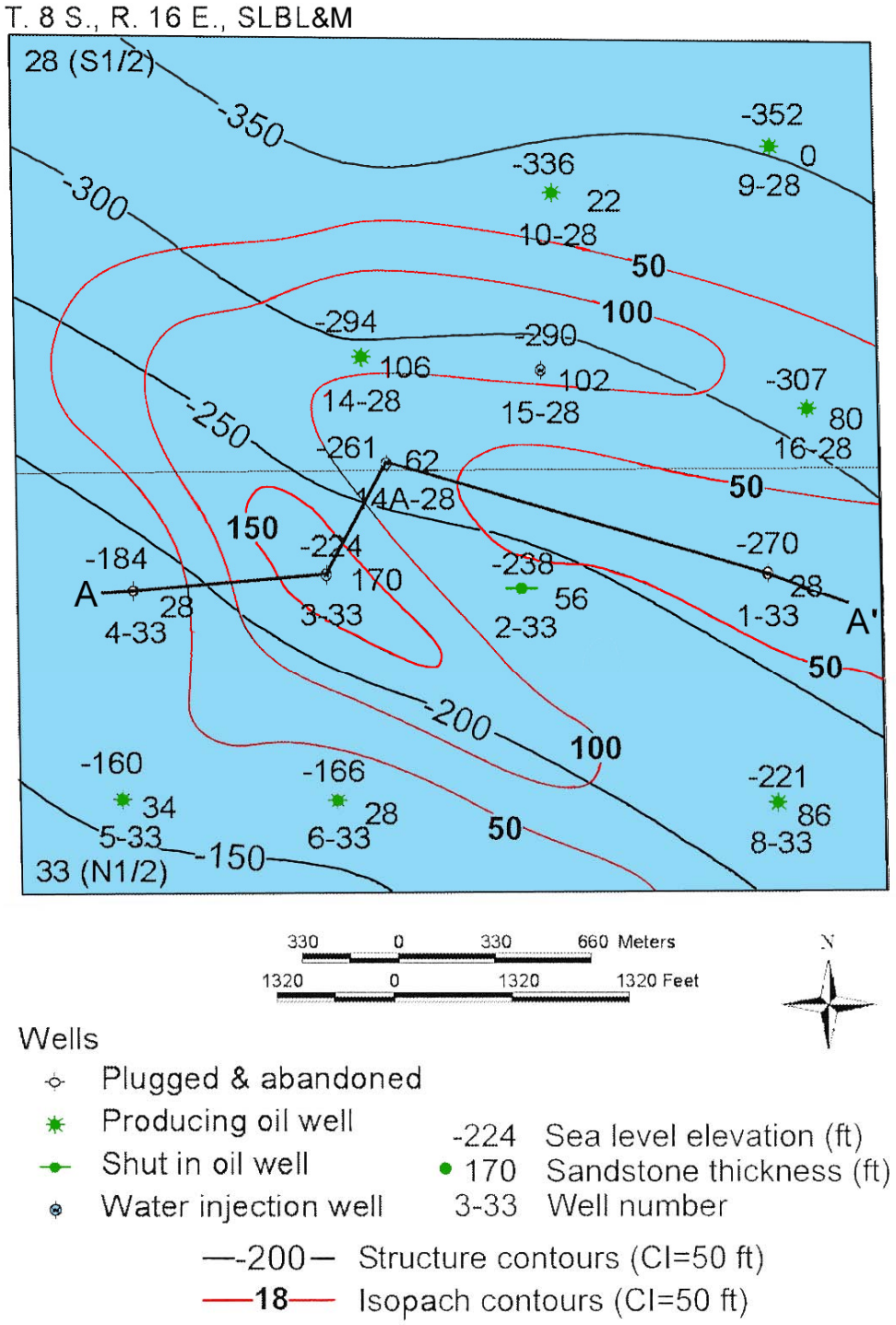


Figure 14-8. Structure map (black contours) on top of a log marker in the upper portion of the Travis reservoir (see figure 14-9), Travis waterflood unit; datum is sea level. Isopach map of sandstone in the Travis reservoir with >10% density log porosity is shown with red contours. Cross section A-A' is figure 14-9.

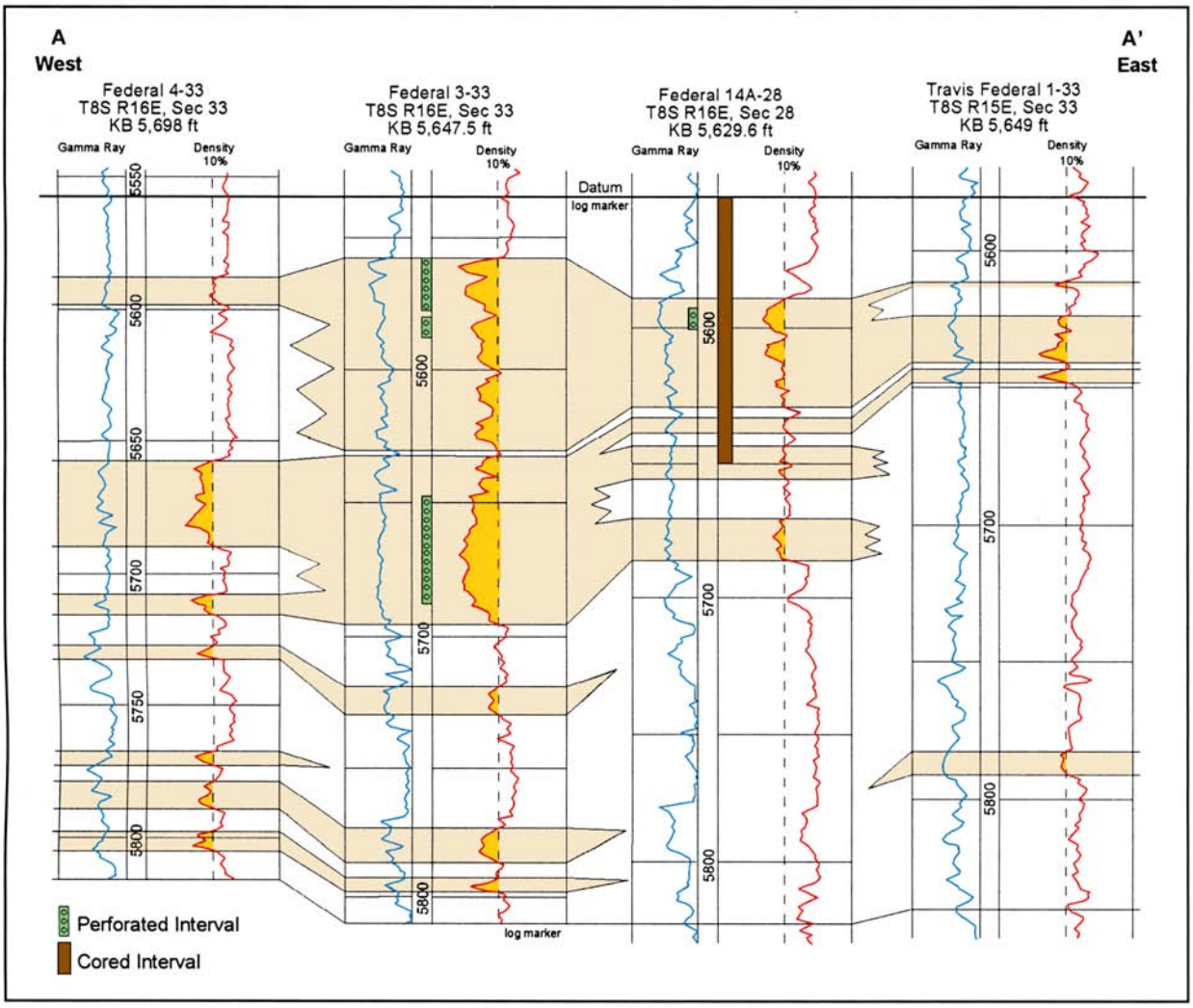


Figure 14-9. West-to-east cross section of the Travis interval in the Travis waterflood unit. Sandstone with >10% density log porosity is shaded orange. See figure 14-8 for location of cross section and an isopach map of the Travis sandstone beds.

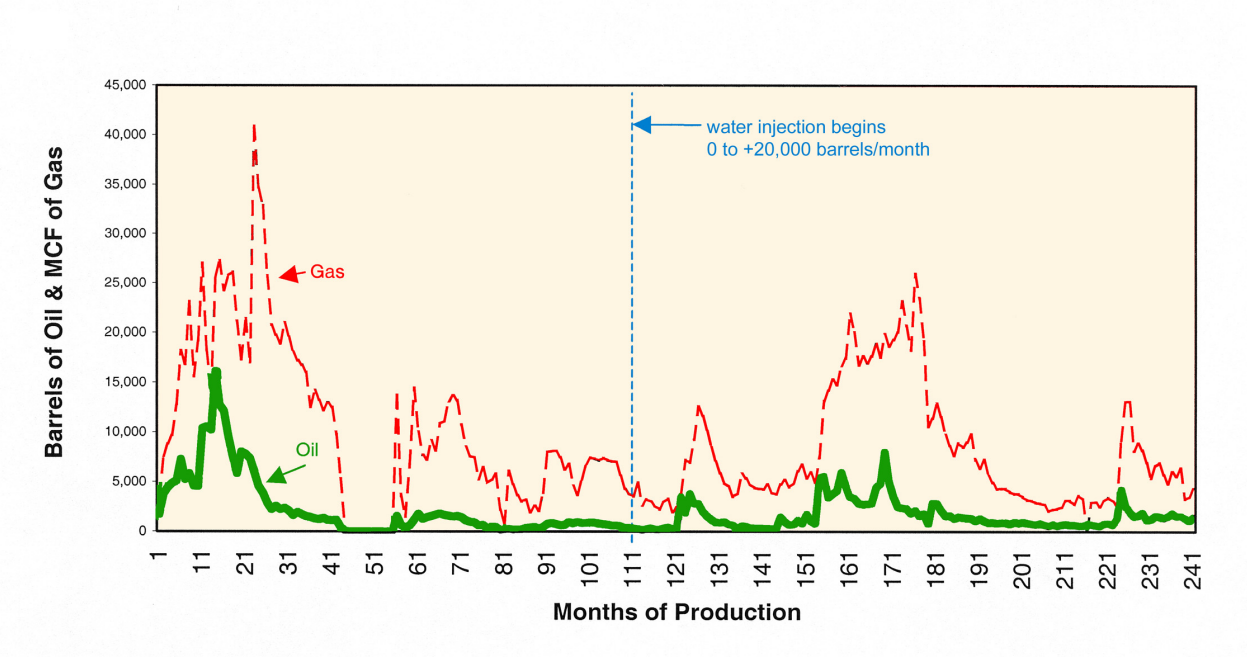


Figure 14-10. Monthly oil and gas produced in the Travis waterflood unit from December 31, 1982, through December 31, 2002. Data source: Inland Production Resources.

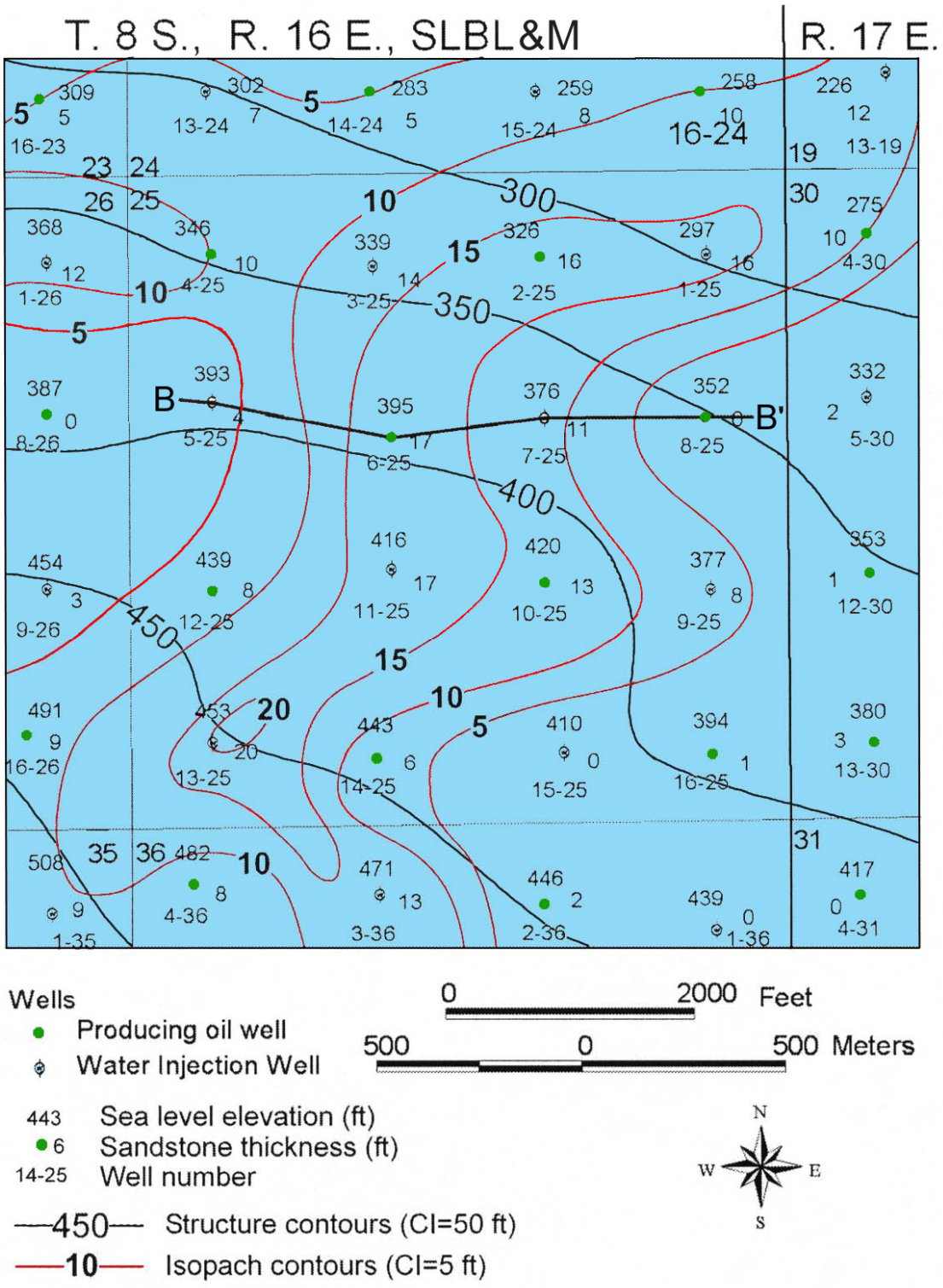


Figure 14-11. Structure map (black contours) on top of the MGR 7 marker (top of Monument Butte interval), Monument Butte Northeast waterflood unit; datum is sea level. Isopach map of the MGR 7b sandstone bed, the most productive bed in the unit, is shown with red contours. Cross section B-B' is figure 14-12.

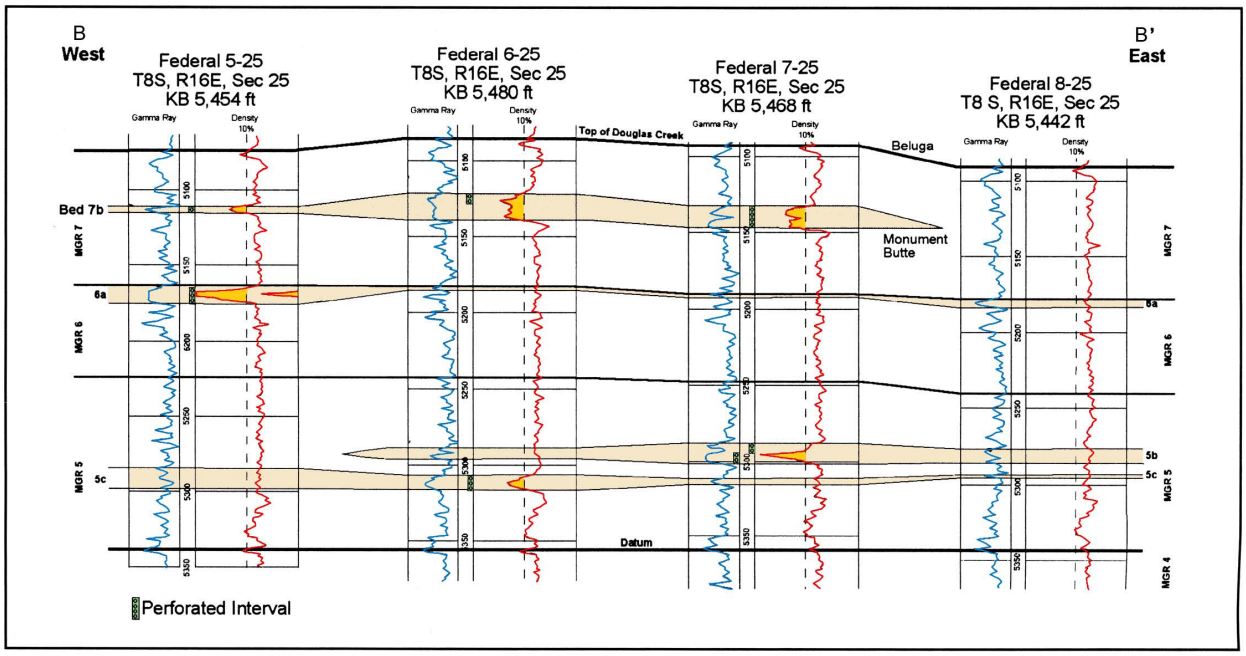


Figure 14-12. West-to-east cross section of a portion of the Monument Butte interval in the Monument Butte Northeast waterflood unit. Sandstone with >10% density log porosity is shaded orange. See figure 14-11 for location of the cross section and an isopach map of the MGR 7b bed.

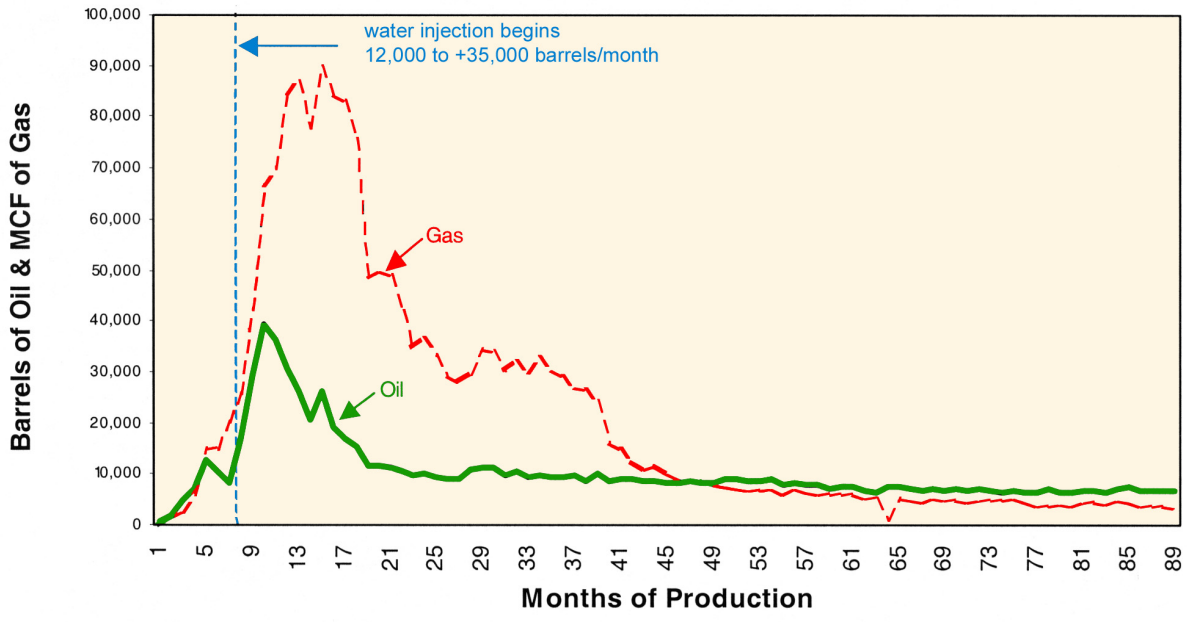


Figure 14-13. Monthly oil and gas produced in the Monument Butte Northeast waterflood unit from August 31, 1995, through December 31, 2002. Data source: Inland Production Resources.

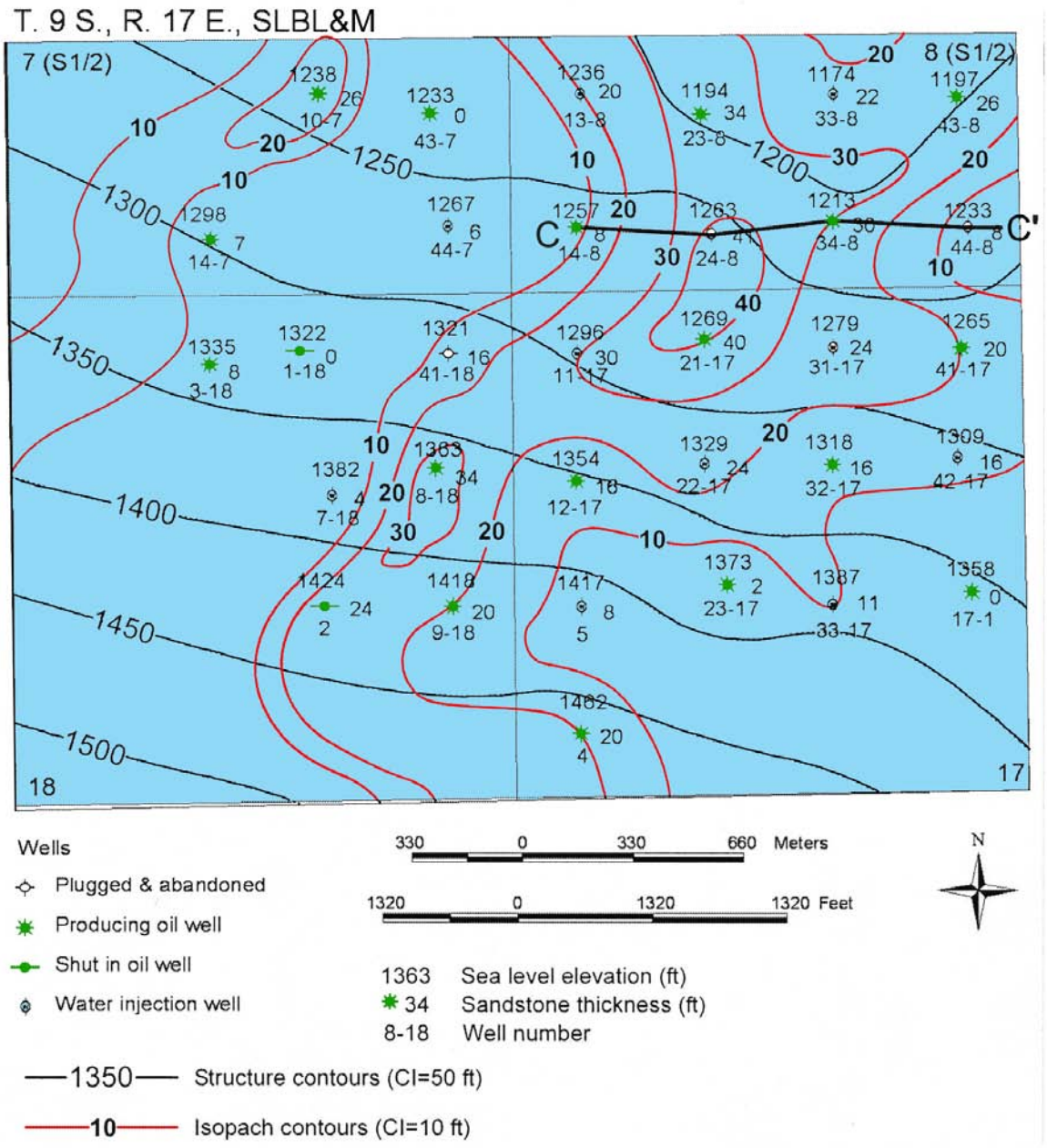


Figure 14-14. Structure map (black contours) on top of the MGR 12 marker, Beluga waterflood unit; datum is sea level. Isopach map of sandstone with >10% density log porosity in the MGR 13 log cycle in the Beluga interval is shown with red contours. Cross section C-C' is figure 14-15.

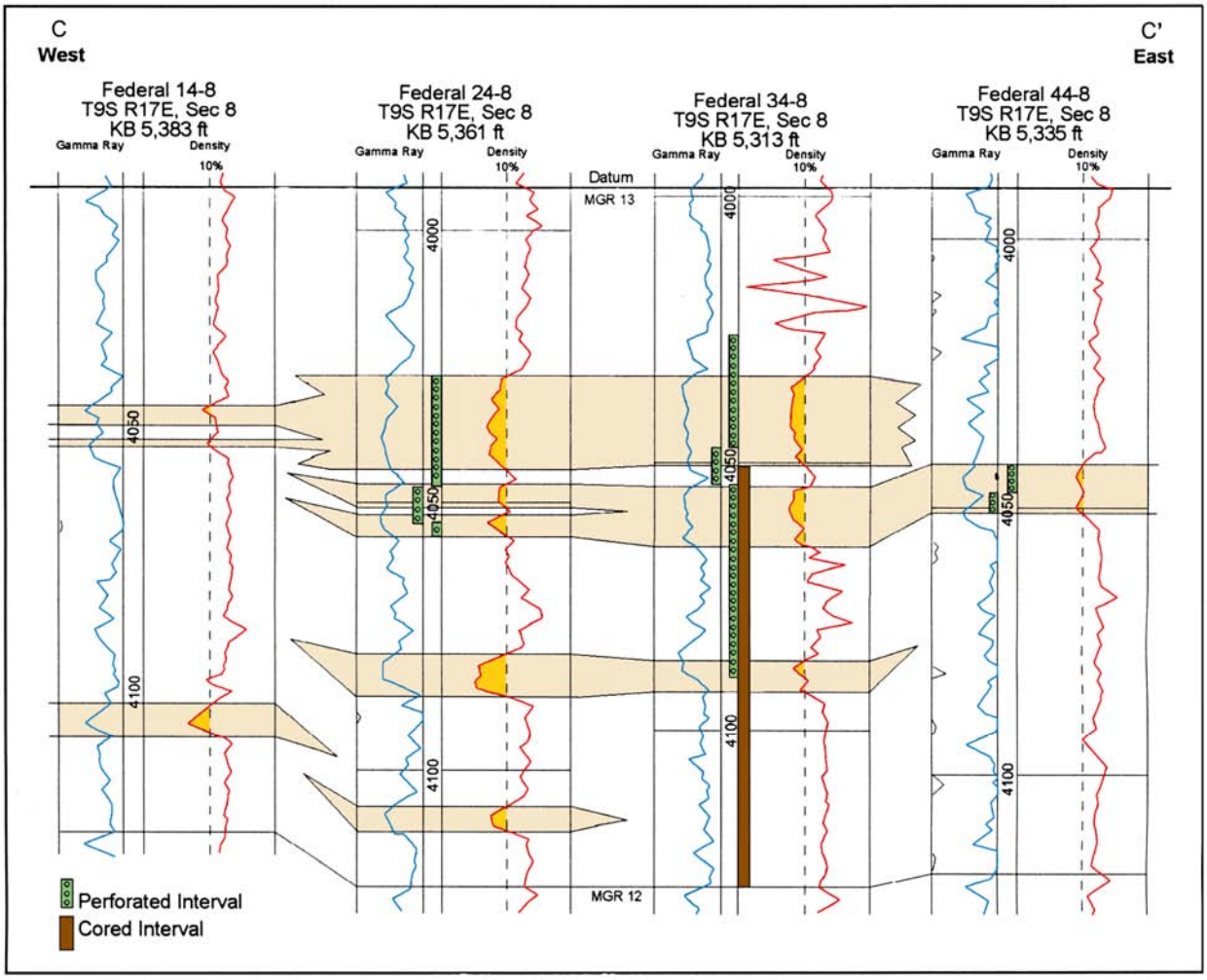


Figure 14-15. West-to-east cross section of the MGR 13 log-cycle in the Beluga interval in the Beluga waterflood unit. Sandstone with >10% density log porosity is shaded orange. See figure 14-14 for location of cross section and an isopach map of the MGR 13 sandstone with >10% density log porosity.

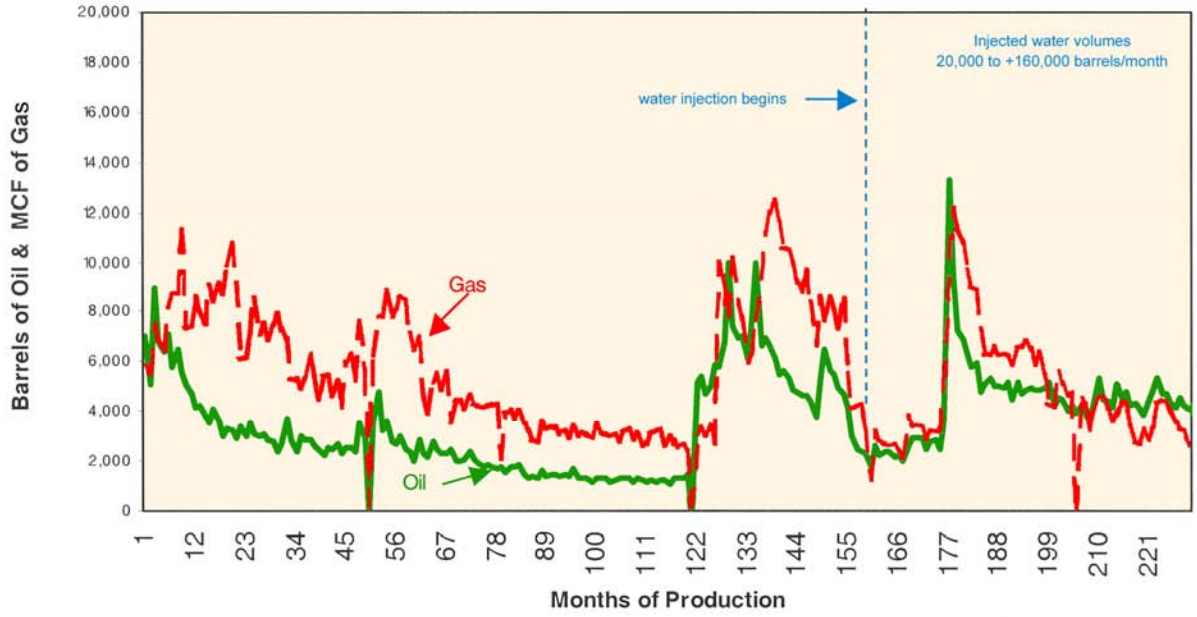


Figure 14-16. Monthly oil and gas produced in the Beluga waterflood unit from January 31, 1984, through December 31, 2002. Data source: Inland Production Resources.

CHAPTER 15 – BEST PRACTICES FOR THE MISSISSIPPIAN LEADVILLE LIMESTONE AND PENNSYLVANIAN PARADOX FORMATION PLAYS, PARADOX BASIN, UTAH, COLORADO, AND ARIZONA

by
Thomas C. Chidsey, Jr., Craig D. Morgan, and J. Wallace Gwynn,
Utah Geological Survey; and
David E. Eby, Eby Petrography & Consulting, Inc.

Introduction

Over 100 fields have been discovered in the Paradox Basin of Utah, Colorado, and Arizona, with production from 800-plus wells. Data were collected from the files of the UDOGM and the COGCC where there is a wealth of publicly available information, and various publications for selected fields in the basin. This information includes structure maps and cross sections, production and pressure data, completion reports, drilling and development plans, and testimony given at spacing hearings and other hearings before the UDOGM, and the COGCC. The purpose of this data collection was to help determine the best drilling, completion, and secondary/tertiary recovery techniques for these and similar fields. Specific completion and reservoir management practices were described by various operators of oil fields in Paradox Basin.

Best Practices, Leadville Limestone Play

The Mississippian Leadville Limestone produces oil and gas from basement-involved, structural traps with closure on both faulted and unfaulted anticlines. Lisbon and Big Flat fields, Utah (figure 9-2), are examples of both types of structural traps, respectively, and the best practices for each are described in the following sections. Two significant practices were or could be employed in the later development of Lisbon and Big Flat fields to enhance the ultimate recovery of oil: (1) reinjection of produced gas for pressure maintenance, and (2) horizontal drilling.

Lisbon Field, San Juan County, Utah

Lisbon field (described in Chapter IX) is an elongate, asymmetric, northwest-trending anticline bounded on the northeast flank by a major, basement-involved normal fault (Smith and Prather, 1981) (figures 9-2 and 9-9). Most of the Leadville oil production in the Paradox Basin is from Lisbon. Producing units contain dolomitized crinoidal/skeletal grainstone, packstone, and wackestone fabrics. Diagenesis includes autobrecciation, karst development, hydrothermal dolomite, and bitumen plugging. Reservoir quality is greatly improved by natural fracture systems associated with the Paradox fold and fault belt. Porosity averages 6% in intercrystalline and moldic networks enhanced by fractures; permeability averages 22 mD. The drive mechanism is an expanding gas cap and gravity drainage; water saturation is 39% (Clark, 1978; Smouse, 1993b). The bottom-hole temperature ranges from 153 to 189ºF (67-87ºC). The

produced associated gas contains various hydrocarbon fractions as well as carbon dioxide, hydrogen sulfide, and helium (Stowe, 1972).

Lisbon field was discovered in 1960 with the completion of the Pure Oil Company No. 1 NW Lisbon USA well, NE1/4NW1/4 section 10, T. 30 S., R. 24 E., SLBL&M (figure 9-9), with an initial flowing potential (IFP) of 179 BOPD (28 m^3) and 4376 MCFGPD (124 MCMPD). The original reservoir field pressure was 2982 psi (20,560 kPa) (Clark, 1978). There are currently 22 producing (or shut-in wells), 11 abandoned producers, five injection wells (four gas injection wells and one water/gas injection well), and four dry holes in the field. Cumulative production as of January 1, 2008, was 51,129,974 bbls of oil (8,129,666 m^3), 779.3 BCFG (22.1 BCMG) (cycled gas), and 49,936,145 bbls of water (7,939,847 m^3) (Utah Division of Oil, Gas and Mining, 2008).

Pressure maintenance: Lisbon field encompasses a large area with significant structural closure. As a result, Lisbon has a thick hydrocarbon column, which includes a gas cap and oil ring. A gas plant (figure 15-1) was built at Lisbon field in 1962, and 60 MMCFGPD (1.7 MMCMGPD) of associated sour (hydrogen sulfide) gas was reinjected into the gas cap to maintain reservoir pressure and maximize the oil recovery. Natural gas liquids recovery facilities (figure 15-1) were added in 1966, and for 27 years lean, processed, sour gas was recycled into the reservoir. Gas-sweetening, nitrogen-injection, and helium-recovery facilities were installed in 1992, and in 1993 the operator began gas cap blowdown and sale of residual gas. A detailed discussion of the Lisbon gas plant was published by Jones and others (2004a, 2004b).

Drilling and completion: The Leadville Limestone is at drill depths from 7500 to 9500 feet (2300-2900 m) at Lisbon field. Wells in the field were typically drilled to a depth of 10 to 70 feet (3-23 m) where a conductor was set; the diameter varied from 13.375 to 20 inches (34-51 cm). Surface casing ranging in diameter from 9.675 to 10.75 inches (24-27 cm) was set from 300 to 4317 feet (90-1316 m), but most was set at 700 to 1200 feet 210-370 m). The wells were drilled to total depth and 5.5- to 7-inch (14-18 cm) diameter casing was set. The wells were drilled with fresh-water mud to the top of the Paradox Formation salt, after which a natural brine or salt-base mud was typically used to total depth.

The wells were completed by perforating high-quality porosity intervals in the Leadville Limestone with four shots per foot (occasionally at two shots per foot). The gross perforated interval ranged from 6 to 394 feet (2-121 m); most intervals were less than 200 feet (60 m) and the average gross perforated interval was 125 feet (38 m) (figure 15-2). Due to one well, the net perforated interval also ranged from 6 to 394 feet (2-121 m); however, most were from 6 to 50 feet (2-15 m) and an average net perforated interval of 72 feet (22 m) (figure 15-3). The typical completion treatment was to stimulate the perforated intervals with 15% hydrochloric (HCl) acid. Treatment volumes ranged from 0 to 1167 gallons of acid per foot (gal/ft) (0-14,504 L/m) of perforation, most were 0 to 150 gal/ft (0-1864 L/m) with an average of 149 gal/ft (1852 L/m) (figure 15-4).

In addition to the wellhead and tank batteries, the typical producing well site includes dehydrators, heated separators (heater/treaters), double-walled emergency pit tanks, and solar-powered flow meters for monitoring production data remotely (figure 15-5).

Big Flat Field, Grand County, Utah

Big Flat field (described in Chapter IX) was the first Mississippian discovery in the Paradox Basin (figure 9-2). The trap is a north-south-trending anticline (figure 9-8). Porosity ranges from 4 to 14% in vuggy and intercrystalline pore systems within limestone and dolomite that are enhanced by vertical fractures (Smith, 1978b). Permeability varies and is dependent, therefore, on the extent of fracture development. The drive mechanism is water drive with an inert gas cap and the initial water saturation was 30 to 50% (Smith, 1978b).

Big Flat field was discovered in 1957, with the completion of the Pure Oil Company No. 1 Big Flat Unit well (figure 9-8), SW1/4SE1/4 section 14, T. 26 S., R. 19 E., SLBL&M; IFP was 319 BOPD (51 m^3/d). The original Leadville reservoir field pressure was 2450 psi (16,900 kPa) (Smith, 1978b).

The Leadville reservoir was abandoned in 1968. Cumulative Leadville production was 83,469 bbls of oil (13,272 m^3), 52.4 BCFG (1.5 BCMG), and 41,950 bbls of water (6670 million m^3) from three wells from 1957 through 1967 (Stowe, 1972).

The drilling and completion techniques for Big Flat field are older and represent a much smaller data set than provided from Lisbon field, but are not significantly different. Big Flat field did not have a gas cap and there were no attempts to maintain reservoir pressure or increase recovery through secondary or tertiary methods.

Drilling practices: The Leadville Limestone is at drill depths from 7500 to 7800 feet (2300-2400 m) at Big Flat field. Wells in the field were typically drilled to a depth of 10 to 30 feet (3-10 m) where a conductor was set; the diameter varied from 16 to 20 inches (41-51 cm). Surface casing 13.375 inches (34 cm) in diameter, was set from 480 to 1000 feet (150-300 m). An intermediate, 9.675-inch (24 cm) diameter casing string was set into the top of the Paradox Formation salt with 7-inch (18 cm) diameter casing set to total depth. The wells were drilled with air or fresh-water mud to the top of the Paradox Formation salt, after which a natural brine or salt-base mud was typically used to total depth.

Completion practices: The wells were completed by perforating high-quality porosity intervals in the Leadville Limestone with four shots per foot (occasionally at two shots per foot). The gross and net perforated interval ranged from 12 to 52 feet (4-16 m). The average gross perforated interval was 33 feet (10 m) and the average net perforated interval was 27 feet (8 m). The oil column was much smaller at Big Flat field compared to Lisbon field; as a result, the gross and net perforated intervals are very similar. The typical completion treatment was to stimulate the perforated intervals with 15% HCl. Treatment volumes ranged from 10 to 417 gal/ft (124-5283 L/m), with an average of 163 gal/ft (2026 L/m).

Potential Horizontal Drilling in the Leadville Limestone

Three factors create reservoir heterogeneity within productive zones in the Leadville Limestone: (1) variations in carbonate fabrics and facies, (2) diagenesis (including karstification and various stages of dolomitization), and (3) fracturing. The extent of these factors and how they are combined affect the degree to which they create barriers to fluid flow. Untested compartments created by these conditions may be ideally suited for, as yet to be attempted, horizontal drilling techniques. In addition, horizontal drilling from existing wells minimizes

surface disturbances and costs for field development, particularly in the environmentally sensitive areas of southeastern Utah and southwestern Colorado. For an overview of horizontal drilling principles and general techniques see Chapter XIII.

Applicable drilling techniques: Drilling techniques may include new wells and horizontal, often multiple, laterals from existing vertical wells (as is the case with the Jurassic Twin Creek Limestone described in Chapter XIII and the Pennsylvanian Paradox Formation [described later in this chapter]), preferred in environmentally sensitive areas. Multilaterals exiting a single wellbore (figure 15-6) have gained wide acceptance (Chambers, 1998). Multiple laterals are used where canyons and other rugged terrain are an issue. These laterals may be horizontal or deviated to reach different bottom hole locations. The laterals are drilled from the main wellbore. Branches are drilled from a horizontal lateral into the horizontal plane. Splays (fish hooks or herringbone) are drilled from a horizontal lateral in the vertical plane. A dual lateral is a multilateral well with two laterals. Laterals may be opposed to each other or stacked (figure 15-7). Multilaterals are drilled for cost-saving reasons, or reservoir production reasons associated with improved drainage or injection. They provide a means for increasing wellbore contact with the pay zones, and target untapped reservoir compartments.

Horizontal drilling based on Leadville facies, diagenesis, and fractures: Depositional facies are targeted for horizontal drilling where, for example, multiple carbonate buildups can be penetrated with two opposed sets of stacked, parallel horizontal laterals (figure 15-7). Good porosity zones associated with late-stage, secondary dolomite could be drained with radially stacked, horizontal laterals and splays.

The fracture patterns observed in outcrop and structural orientation can be applied to planning directions and lengths of horizontal wells in Leadville reservoirs. In addition, borehole studies and Formation MicroImager or other fracture-identification geophysical well logs should be used to plan Leadville horizontal drilling programs.

Best Practices, Paradox Formation Play

The Paradox Formation play area includes nearly the entire Paradox Basin (figure 10-1). Trap types include stratigraphic (carbonate buildups), stratigraphic with some structural influence, combination stratigraphic/structural, and diagenetic including fractured zones. The Paradox Formation has heterogeneous reservoir properties because of depositional lithofacies with varying porosity and permeability, carbonate buildup (mound) relief and flooding surfaces (parasequence boundaries), and diagenetic effects. The Paradox Formation play is divided into four subplays (figure 10-4): (1) fractured shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone. In addition to standard well completion operations, three significant practices were or could be employed in the later development of fields in the Paradox Formation play to enhance the ultimate recovery of oil: (1) horizontal drilling, (2) waterfloods, and (3) carbon dioxide (CO_2) floods.

Drilling and Completion Operations

Drilling in the Paradox Formation plays may be vertical, deviated, or horizontal (discussed in more detail in the section below). Well deviation may be necessary due to the

rugged topography in the basin, even within field areas. Wells in fields that produce from the Paradox Formation are typically drilled to a depth of 50 to 300 feet (15-90 m) where a conductor is set; the diameter varies from 13-5/8 to 16 inches. Surface casing varies in diameter (7-5/8, 8-5/8, 9-5/8, 10-3/4, or 13-3/8 inches) and is set in the Triassic Chinle Formation from depths of about 1000 to 2500 feet (300-760 m) to protect shallow aquifers, such as the Jurassic Navajo Sandstone and Morrison Formation, or below the Permian DeChelly Sandstone. Severe water flows can occur in both the DeChelly and Navajo but may be controlled using moderate mud weights up to 10 pounds per gallon (Mickel, 1978d; Lehman, 1993). However, in some cases lost circulation occurs in the Jurassic sandstones and can be resolved with a light treatment of lost circulation material (Martin, 1983). Surface casing is cemented with a regular grade cement treated with 2 to 3% $CaCl_2$ and flocele (an additive consisting of 3/8 - or 3/4-inch cellophane flakes used to control lost circulation [1/4 pound per sack of cement]).

Wells are drilled with a fresh-water mud to the top of the Paradox Formation salt, after which a natural brine, salt-based mud, or gel-based mud is typically used to total depth (Steele, 1993). The mud weight is gradually increased through the Ismay zone (less than 9.5 pounds per gallon) to generally 11.0 to 12.5 pounds per gallon in the Desert Creek zone (which is slightly overpressured in some areas), depending on depth. The mud systems consist of barite, gel (bentonite), and a dispersant such as lignosulfonate (Martin, 1983).

Wells are drilled to total depth either through the Ismay zone and into the Gothic shale, or through the Desert Creek zone and into either the Chimney Rock shale or salt at the top of the Akah zone (figure 10-2); 4-1/2-, 5-1/2-, 7-, 8-5/8-inch diameter casing is then set, occasionally with 2-7/8-inch tubing. If there are no water-flow problems, wells can be completed with 4-1/2-inch casing. Casing is cemented with a 50:50 ratio blend of Portland cement and flyash additive, and up to 4% gel (bentonite). The flyash additive helps reduce the permeability of the set cement, improves the cement's perforating properties, reduces the effects of acid and sulfate, and produces a good cement bond.

Mudlogging should be employed a few hundred feet above the Pennsylvanian Honaker Trail Formation (figure 10-2) to total depth to determine total gas and sample breakdown. Drill cuttings should be collected and described at 5-foot intervals (1.5 m) through the Paradox Formation. It is highly recommended that conventional core is acquired through the target reservoirs in a vertical well. Cores provide petrographic properties, possible fluid contacts, lithofacies, parasequence boundaries, barriers and baffles to fluid flow, and diagenetic history critical to fully understand and model carbonate reservoirs for field development and design enhanced-oil-recovery programs.

Once the zone of interest has been penetrated, and depending on hydrocarbon shows, drillstem tests should be run as soon as possible to prevent formation damage from drilling fluids, which reduces the chance of a successful test. Straddle tests run after reaching total depth have a high failure rate (Martin, 1983).

Wells are evaluated with standard suites of geophysical logs including DLL-MSFL (dual laterolog-microspherically focused log), DIL-SFL (dual induction-spherically focused log) Cal (caliper), GR-SP (gamma-ray and spontaneous potential), CNL-litho-density (compensated neutron log-density log), BHC-Sonic (borehole-compensated sonic), microlog, and occasional dipmeter, as well as mudlogs and rotary sidewall cores. Cased holes are evaluated with a variety of cement, casing, tubing, and production logs. Deviated wells require directional surveys.

Wells are completed by perforating high-quality porosity intervals in the Paradox Formation with two, three, or four shots per foot. Vertical wells are completed with matrix-acid

stimulations, which have historically proven the best method. Treatment volumes require up to 2000 gallons (7600 L) of 15 to 28% HCl. Some reservoirs need a cleanout agent prior to acidization (Campbell, 1978b). In Bug field (figure 10-4), development wells were completed with the tubing hanging open-ended so fresh water could be pumped down the casing-tubing annulus to dilute supersaturated formation brine. This technique prevents salt buildup on the tubing and surface equipment (Martin, 1983).

Fracturing is occasionally performed in low-permeability reservoir units. For example, the lower Desert Creek zone in Bradford Canyon field (figure 10-4) has been fractured with 12,000 to 15,000 gallons of 28% HCl, plus the same volume of gelled water and 800 standard cubic feet of nitrogen per barrel. After the frac treatment, the wells are flowed back and normally completed as flowing wells (Lehman, 1993).

McClean (Cutthroat) field (figure 10-4), Montezuma County, Colorado, was selected as a case-study field for best drilling and completion practices. It is described in the following sections.

McClean field synopsis: McClean field is an elongate, north-northwest-trending carbonate buildup that forms an updip porosity pinch-out in the lower Desert Creek zone (figure 15-8) (Mickel, 1978a). The producing units vary from porous, dolomitized, phylloid-algal (*Kanasphyllum*) boundstone to packstone (Matheny and Longman, 1996). The net reservoir thickness is 30 feet (10 m), which extends over a 1300-acre (526-ha) area. Porosity averages 11%; permeability is highly variable (Mickel, 1978a).

McClean field was discovered in 1974 with the completion of the Mountain Fuel Supply No. 2 well, SW1/4NE1/4 section 15, T. 37 N., R. 19 W.; initial flowing potential was 504 BOPD (80 m^3), 713 MCFGPD (20 MCMPD), and 528 bbls of water per day (84 m^3). The field currently has six producing (or shut-in) wells. The original reservoir field pressure was 3577 psi (24,663 kPa) (Colorado Oil and Gas Conservation Commission, 1985b).

Cumulative production as of January 1, 2008, was 4,512,114 bbls of oil (717,426 m^3) and 5.9 BCFG (0.2 BCMG) (Colorado Oil & Gas Conservation Commission records). Ultimate recovery from good wells is estimated to be as high as 1 million bbls of oil (0.2 million m^3) and 5 BCFG (0.1 BCMG) (Phil Moffit, Questar Exploration and Production Co., verbal communication, 2003).

McClean field optimal drilling, development, and production practices: The Desert Creek zone is overpressured by as much as 1500 psi (10,300 kPa) in the McClean area. After penetrating potential lost-circulation zones in the shallow (950 to 1700 feet [320-570 m]) Jurassic Carmel Formation and Wingate Sandstone, the mud weight must be increased to 12.5 pounds (5.7 kg) above the Desert Creek (Michel, 1978a).

The well spacing for McClean field was originally set at 160 acres (65 ha), but was later changed to general field rules as a result of the formation of a federal exploration unit due to problems associated with rough topography, archeological findings, and competitive drilling locations. The oil is highly volatile, 46.2° API gravity and a gas-to-oil ratio of 1622, requiring an expensive, centralized treatment facility to increase recovery (Colorado Oil and Gas Conservation Commission, 1985a, 1987).

To enhance the ultimate recovery from McClean field, fresh water is injected down the tubing and casing to keep the natural brine from precipitating salts. In addition, produced water from pumping oil wells is used to create a mixture with non-reservoir water. This mixture of

water is injected into the reservoir downdip to (1) reduce salt precipitation, (2) dispose of produced water, and (3) maintain reservoir pressure thus creating a low-cost waterflood (Phil Moffit, Questar Exploration and Production Co., verbal communication, 2003).

Horizontal Drilling

Introduction: Like the Leadville Limestone, three factors create reservoir heterogeneity within productive zones in the Paradox Formation: (1) variations in carbonate fabrics and lithofacies, (2) diagenesis (particularly various stages of dolomitization), and (3) fracturing. Thus, untested compartments created by these conditions may be ideally suited for horizontal drilling techniques. As with any petroleum exploration and development in the environmentally sensitive Paradox Basin, horizontal drilling from existing wells minimizes surface disturbances and costs for field development. For an overview of horizontal drilling principles and general techniques see Chapter XIII.

Historical aspects: With the exception of the giant Greater Aneth field (figure 10-4), the value of horizontal drilling has not been demonstrated in any of the over 100 smaller shallow-shelf carbonate reservoirs in the Paradox Basin (Blanding sub-basin Desert Creek zone, Blanding sub-basin Ismay zone, and Aneth platform Desert Creek zone subplays). The reservoirs are heterogeneous due to lithofacies changes and extensive diagenesis within the Ismay and Desert Creek zones, leaving untapped compartments. To date, only two horizontal wells have been drilled in small Ismay (Knockando) and Desert Creek (Mule) fields (figure 10-4). The results from these wells were disappointing in terms of encountering the objective reservoir lithofacies and production (Chidsey, 2002). Recently in the northern Paradox Basin, horizontal drilling successfully reopened old fields and led to discoveries in the Cane Creek shale – the Paradox Formation fractured shale subplay (Morgan, 1992a, 1992b).

Carbonate reservoirs that have successfully been drilled with horizontal wells include pinnacle reefs in the Alberta basin, the Madison Group in the Williston basin, Permian Basin reefs, and Devonian and Silurian pinnacle reefs in the Michigan basin. The purpose of horizontal drilling in these carbonate reservoirs was to: solve water-, solvent-, and/or gas-coning problems; control water production; improve light oil production; and encounter off-reef lithofacies or karsted reef surfaces. These drilling programs were not designed to encounter untapped reservoir compartments. The results of these drilling projects are summarized by Jones (1992), LeFever (1992), and Wood and others (1996). The horizontal wells in these plays have generally higher success rates, higher initial flowing potentials (20 to 50%), lower drilling costs, and require fewer wells to drain a reservoir than vertical wells.

Horizontal drilling techniques: Drilling techniques including new horizontal wells and multiple horizontal laterals from existing vertical wells were discussed above in the **Applicable Drilling Techniques** section above for the Leadville Limestone best practices and valid for the Paradox Formation as well (figure 15-9). Mud-log interpretation and rate of penetration (ROP) are the only source of reservoir quality information in the lateral. Rate of penetration is a real-time indicator used to steer the well. In good porosity lithofacies, ROP averages between 0.5 to 3 minutes/foot. In poor porosity lithofacies, ROP slows down to 9 minutes/foot (Amateis and Hall, 1997). Adjustments are made for particular lithofacies within the target zone as the laterals

are drilled using the cuttings, ROP, and MWD techniques. Cross sections serve more as a guide than an absolute target since porosity and permeability are not very predictable.

Wellsite recommendations:

1. Carefully collect and examine drill samples (cuttings) during horizontal drilling operations.

2. Use a good binocular (research-grade) microscope capable of high magnification. It should be equipped with a daylight-corrected fiber optics lighting system to determine porosity types, mineralogy, and lithofacies being drilled. These properties should be documented and accurately logged to accompany mudlogging data.

3. Utilize UV and blue-light fluorescence microscopy to assist with the evaluation of oil shows while drilling the horizontal leg(s).

4. Wellsite assessment of rock/fluid properties using the microscopic techniques listed above should be used in helping to determine when to cease drilling each horizontal leg/lateral.

5. Immediately after drilling, make selective thin sections from the cuttings in order to confirm the rock and fluid properties of the section that was drilled horizontally. With thin sections, the cuttings should be thoroughly evaluated using epifluorescence, cathodoluminescence, and polarized light microscopy.

Completion operations: Horizontal wells are usually completed open hole, cemented, or with an uncemented, pre-perforated liner in the horizontal leg, as is the case in the Cane Creek shale (Grove and others, 1993).

Thermal decay time (TDT) logs along the laterals help to visualize the variability of the porosity units and identify favorable oil saturations, as well as thin units acting as barriers to fluid flow (Amateis, 1995). The relative water saturations along the wellbore change rapidly laterally. Salinity of the water cannot be estimated so saturations are qualitative rather than quantitative, but are clear indicators of the compartmentalization of the reservoir by surfaces not easily incorporated in 3-D models (Amateis and Hall, 1997).

Horizontal wells/laterals are also completed with matrix-acid stimulations. To obtain matrix stimulation on a multilateral well, acid must be evenly placed in each lateral. Acid must be pumped at matrix pressures and rates. Each lateral must be isolated from the other laterals. Bullhead acid treatments provide higher rates and bottom-hole treating pressures but poor acid distribution. At Greater Aneth field for example (figure 10-4), matrix stimulation of a multilateral well has not been easy and has only been achieved on a few wells (Amateis and Hall, 1997).

Fractured shale subplay: In the fractured shale subplay, the Cane Creek shale zone has the following characteristics favorable for horizontal drilling: (1) it is a fractured reservoir; (2) it contains organic-rich, petroleum-generating source rocks with total organic carbon as high as 15% (Hite and others, 1984); (3) it has proven production of high-gravity oil; (4) it is

overpressured; (5) it has wide regional extent (cycle 21 of the Paradox Formation); and (6) it has little associated water (Morgan, 1992a). Horizontal drilling increases the probability of encountering the near-vertical fractures needed for economic oil production.

The horizontally drilled wells in the fractured shale subplay have a high success rate and the wells typically produce more than 300,000 BO (48,000 m^3). For example, at Park Road field (about 0.5 miles [0.8 km] north of Dead Horse Point State Park, Grand County, figure 10-1) the Kane Springs No. 19-1A discovery well was drilled 2011 feet (613 m) horizontally in the Cane Creek shale in a north-northeast direction (away from the park) to encounter fractures on an anticlinal nose (figure 10-33). The well initially tested 1158 BO per day (184 m^3/d) and is expected to ultimately recover between 475,000 and 1 million bbls (75,500 and 159,000 m^3) (Grove and others, 1993).

Localized folds create a significant challenge to keeping a horizontal well in the productive zone of the Cane Creek shale during drilling. There has been no attempt to down space because it is believed that the wells are draining the fractures for a long distance beyond the wellbore. However, there are few wells and the density and connectivity of the fracture systems on individual structures is still poorly understood. Careful production procedures are required to prevent a rapid drop in the fluid pressure that could cause closure of the fracture network around wellbores.

Blanding sub-basin Desert Creek zone and Ismay zone subplays: The typical vertical sequence or lithofacies from Desert Creek and Ismay fields in the Blanding sub-basin, as determined from conventional core and tied to its corresponding log response, help identify reservoir and non-reservoir rock (such as false porosity zones on geophysical well logs) and determine potential units suitable for horizontal drilling. Structure contour maps on the top of the upper Ismay zone and the Chimney Rock shale and isochore maps of the upper Ismay and lower Desert Creek, respectively, show carbonate buildup trends, define limits of field potential, and also indicate possible horizontal drilling targets.

Elongate, northwest-southeast-trending carbonate buildups depict typical, nearshore, shoreline-linear lithofacies tracts of the Desert Creek zone in the northern Blanding sub-basin. Small saddles may represent intermound troughs between two subsidiary buildups. Intermound troughs may be filled with low-permeability wackestone and mudstone, thus acting as barriers or baffles to fluid flow. The relatively small size and abundance of intermound troughs over short distances, as observed in outcrop along the San Juan River for example, suggest caution should be used when correlating these lithofacies between development wells (Chidsey and others, 1996d). Lithofacies that appear correlative and connected from one well to another may actually be separated by low-permeability lithofacies and carbonate rock fabrics which inhibit flow and decrease production potential. Horizontal wells, or laterals, increase the chance of successful drainage where these troughs are present.

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of Desert Creek and Ismay fields are indicators of reservoir flow capacity, storage capacity, and potential for horizontal drilling. The reservoir quality of these fields has been affected by multiple generations of dissolution, anhydrite plugging, and various types of cementation which act as barriers or baffles to fluid flow. Diagenetic characteristics from the Desert Creek zone include extensive, early-stage micro-boxwork porosity due to dissolution related to subaerial exposure of carbonate buildups. Ismay zone diagenetic characteristics include intense, late-stage microporosity development along hydrothermal solution fronts. Micro-boxwork porosity and

microporosity in the Desert Creek and Ismay zones, respectively, represent important sites for untapped hydrocarbons and possible targets for horizontal drilling.

Three strategies for horizontal drilling are recommended for Desert Creek and Ismay fields in the Blanding sub-basin subplays (figure 15-10). All strategies involve drilling stacked, parallel horizontal laterals. Depositional lithofacies should be targeted where, for example, multiple buildups can be penetrated with two opposed sets of stacked, parallel, horizontal laterals (figure 15-10A). The hydrothermally induced microporosity in the Ismay zone does not appear to be lithofacies dependent and therefore could be drained with radially stacked, horizontal laterals and splays (figure 15-10B). Finally, much of the elongate, brecciated, beach-mound depositional lithofacies and micro-boxwork porosity in the Desert Creek zone could be penetrated by opposed sets of stacked, parallel, horizontal laterals (figure 15-10C).

Aneth Platform Desert Creek zone subplay: An extensive and successful horizontal drilling program has been conducted in the giant Greater Aneth field (figure 10-4). These drilling programs were carried out primarily in the Aneth (in 1996) and Ratherford (in 1994) units in the northwest and southeast parts of the field, respectively (figures 15-11 and 15-12). Short-reach or horizontal lateral drilling programs at Greater Aneth field included wells with two opposed sets of three stacked parallel laterals with lengths of 860 to 960 feet (260-290 m), similar to that shown schematically on figures 15-9 and 15-10. The purpose of this program was to encounter subzones that were basically untouched by waterflooding, discussed in the next section, and to slant through vertical barriers to overcome permeability problems and increase production (Amateis, 1995). Parasequence boundaries, non-algal zones, original oil in place (OOIP), net pay, and sweep efficiency (described in the section below) were the main criteria used to choose the location of horizontal laterals. In addition, horizontal laterals were drilled in northwest and southeast directions to encounter small-scale faults (5 to 40 feet [2-12 m]) that likely divide the reservoir into segments. Production tests averaged 700 bbls of oil per day (BOPD [110 m^3/d]) with rates as high as 1127 BOPD (179 m^3/d) and 461 BWPD (73 m^3/d). While the rates were encouraging, high early declines indicated the need for injection support.

Several different completion methods have been tried on the open-hole multilaterals at Greater Aneth field. Methods ranged from no acid stimulation, to acid washing, to bullhead acidizing, to perforated subs. After producing unacidized wells for a few months at Greater Aneth field, the same wells were acidized. The average acid stimulation paid out in four months (see Amateis and Hall, 1997, p. 134-135 for procedural notes on doing the acid-washing and bullhead acid treatments). Distribution of acid during the acid-washing treatments in the field was excellent, but injection rates and bottom-hole treating pressures were low. A comparison of acid treatments based on early oil production per lateral at Greater Aneth shows that acid-washing and bullhead treatments have similar results.

Waterfloods

Waterfloods are the most common type of secondary oil recovery technique in the Paradox Basin. After primary oil production has declined, water is injected into the reservoir to push (via immiscible displacement) remaining oil to offsetting producing wells. Ultimate oil recovery may increase by over 40% with waterflooding.

Basic concepts: During primary oil production a reservoir will reach a point of maximum production after which reservoir pressure depletion occurs and production declines to where it will no longer be economically viable (step 1 on figure 15-13). Waterflooding the reservoir reverses the production decline. For example, in a solution-gas-drive reservoir, injected water from a commonly used five-spot well pattern (four injection wells around a producing well) forms a water bank that pushes a newly formed oil bank toward the producing well (figure 15-14A). Ahead of the oil bank, the pore space has a high water or gas saturation (step 2 on figure 15-13). Over time the oil bank reaches the producing well and the pore space becomes highly saturated with oil displacing the gas (step 3 on figure 15-13; figure 15-14B). The reservoir is at fill-up and oil production increases significantly. Eventually the water bank reaches the producing well and water breakthrough occurs (step 4 on figure 15-13; figure 15-14C). At this point, oil production declines and water production increases until the reservoir reaches its economic limit (operation costs are equal to or greater than production revenue) (Rottmann, 1998). Additional oil reserves may remain in the reservoir but other recovery techniques would be required, as discussed later.

Screening criteria: Depth, drive mechanisms, and water, oil, and gas saturations are major factors to determine candidate reservoirs for waterflood programs. The higher the initial gas to oil ratio (GOR), the poorer the oil recovery from waterflooding; more reservoir pore space contains gas (Green, 2007). Generally, the initial GOR for Paradox Formation reservoirs is less than 1000 cubic feet/bbl. Low-pressure, low-GOR reservoirs often have waterflood to primary oil recovery ratios in excess of 2:1 (Green, 2007). Very few Paradox reservoirs have higher than normal pressure, with most in the 1600 to 2200 psi (11,000-15,000 kPa) range. Water-drive reservoirs are usually not good candidates for waterflooding. The drive mechanisms for most Paradox reservoirs are solution gas, gas expansion, fluid expansion, or pressure depletion. Solution gas is an inefficient drive mechanism for primary production, but such reservoirs are good candidates for waterflooding because of higher oil saturations at depletion (Rottmann, 1998).

Water sources: Due to the arid climate of the Paradox Basin, water requirements are a critical concern. Most waterfloods require tapping shallow, freshwater aquifers with one or more wells. Produced water from the Paradox Formation can also be used. Total dissolved solids vary widely from 80,000 to nearly 350,000 parts per million. Injected water must be evaluated for acidity, microbial growth, minerals present, alkalinity, temperature, turbidity, dissolved and suspended solids, and compatibility with natural reservoir fluids in planning waterflood programs as they can cause major problems in the carbonate reservoirs in the Paradox Formation (Green, 2007).

Reservoir modeling and simulation to plan waterflooding programs: Reservoir three-dimensional (3-D) modeling and simulation should be major components in designing waterflooding programs for Paradox Formation. High-speed, state-of-the-art computer capability requires accurate and detailed geologic characterization and reservoir engineering data to predict waterflood performance. Numerical waterflood simulations with five-spot and nine-spot injection well patterns illustrate the significant impacts of parasequence boundaries and reservoir heterogeneity created by the shale, anhydrite, and low-permeability carbonate rocks common in the Paradox Formation. Results of 3-D modeling and numerical simulation can (1)

estimate oil recovery and water cut, (2) determine the spacing and pattern of vertical wells, and (3) predict the viability of horizontal wells in waterflood programs.

Examples: Waterflooding began at Greater Aneth field in 1961, just five years after the field was discovered. Kiva, Kachina, Tin Cup Mesa, Gothic Mesa, Ismay, and Cave Canyon fields, San Juan County, Utah, (figure 10-4) also use, or have used, waterfloods for secondary oil recovery. For these fields the most important factors for water injection are reservoir geometry, porosity, permeability, and continuity of these rock properties. Economic factors are also very significant, particularly for many of the small fields typically found in the Paradox Basin. Three examples are described below.

Kiva field – Kiva field was discovered in 1984 and has produced 2,661,759 BO (423,220 m^3/d) (Utah Division of Oil, Gas and Mining, 2008). Kiva produces from the upper Ismay zone. The reservoir is a relatively narrow, elongate, northwest-southeast-trending phylloid-algal buildup (figure 15-15) composed of limestone and dolomite that forms a stratigraphic trap resulting from a mound to off-mound lithofacies change.

Gas reinjection was initiated in 1986 but was not able to compensate for production withdrawals that resulted in partial depletion of reservoir pressure (Crawley-Stewart and Riley, 1993a). Five downdip water injectors were drilled in a generally peripheral pattern to create a natural water drive; four injectors were active in 2006. The water sources are sandstones (1600 to 3200 feet [490-980 m]) in the Permian Cutler Group from an off-feature well and produced water. The reservoir responded favorably to the waterflood since it was initiated in 1987 with an early rapid increase in production followed by a slow decline (figure 15-16). In 2006, the average daily injection rate was 1038 bbls of water (BW) (165 m^3) per day and the average injection pressure was 429 psi 2950 (pKa) (Utah Division of Oil, Gas and Mining, 2006).

Kachina field – Kachina field was discovered in 1986 and has produced 2,616,017 BO (415,947 m^3/d) (Utah Division of Oil, Gas and Mining, 2008). Kachina also produces from the upper Ismay zone. The reservoir is a small, equant to slightly northwest-southeast-trending phylloid-algal buildup (figure 15-17) composed of limestone and dolomite that forms a stratigraphic trap resulting from a mound to off-mound lithofacies change similar to Kiva field.

The reservoir was initially produced at a high rate until it went below the bubble point at 1900 psi (13,100 kPa). The field was shut-in to repressure the reservoir for waterflooding (Crawley-Stewart and Riley, 1993b). Three water injectors were drilled in a partial peripheral pattern using water in the Cutler Group from an off-feature well; two injectors were active in 2006. The reservoir responded favorably to the waterflood since it was initiated in 1989 with an early production increase followed by a slow decline (figure 15-18). In 2006, the average daily injection rate was 1984 BW (316 m^3) per day and average injection pressure was 878 psi (6054 pKa) (Utah Division of Oil, Gas and Mining, 2006).

Greater Aneth field – Greater Aneth field produces primarily from the Desert Creek zone which is divided into two subzones: a lower interval composed predominantly of phylloid-algal buildup lithofacies, and an upper interval composed of oolitic-peloidal calcarenite lithofacies (Peterson and Ohlen, 1963; Babcock, 1978a, 1978b, 1978c, 1978d; Peterson, 1992; Moore and Hawks, 1993). These subzones create a west-northwest-trending reservoir buildup (figure 10-13). The

primary reservoir at Greater Aneth field consists of limestone (algal boundstone/bafflestone and oolitic, peloidal, and skeletal grainstone and packstone) and finely crystalline dolomite.

Waterflood operations are used in all four field units (figure 15-11) – the largest waterflood program in Utah. There are about 300 water injection wells in the field (over 500 injection wells in the past). Both fresh and produced water are used. In 2006, the average daily injection rate for the entire field was nearly 94,000 BW (15,000 m^3) per day; 55,923 BW (8892 m^3), 19,759 BW (3142 m^3), 16,316 BW (2594 m^3), and 1688 BW (268 m^3) per day for the Aneth, McElmo Creek, Ratherford, and White Mesa units, respectively. The average injection pressures were 2250 psi (15,510 pKa), 2191 psi (15,110 kPa), 1848 psi (12,740 kPa), and 750 psi (5170 kPa) in the Aneth, McElmo Creek, Ratherford, and White Mesa units, respectively (Utah Division of Oil, Gas and Mining, 2006). The waterflood programs at Greater Aneth field units utilizing vertical wells will recover 15 to 20% or approximately 230 million BO (37 million m^3) of the 1100 million BO (175 million m^3) total reserves in place (Babcock, 1978a, 1978b, 1978c, 1978d; Peterson, 1992). Figure 15-19 shows the oil production history from the McElmo Creek unit which uses only vertical wells for its waterflood program. In 1976, the well spacing was reduced from 80 acres to 40 acres (32-16 ha), the infill wells creating a five-spot injection pattern (Rudy Smith, ExxonMobil Production, verbal communication, June 22, 2004).

At McElmo Creek unit, areas of higher water injection correspond to high reservoir permeability (Weber and others, 1995b) (figure 15-20). Maximum water injection, production, and other engineering performance maps combined with various geologic reservoir maps (porosity, lithofacies [incorporating sequence stratigraphy], isopach maps, and so forth) help identify wells, trends, and areas that can require adjustments to how the waterflood operation is conducted. For example, these maps may lead to workovers, recompletions, producers converted to injectors, and acid stimulation to improve the injection well pattern and well performance, and thus increase ultimate oil recovery (Weber and others, 1995b).

Until horizontal drilling technology was developed in the 1990s, the waterflood programs at Greater Aneth used a radial five-spot flow pattern where stream lines of water displace oil from a point source of injection to point sources of production, leaving some parts of the reservoir poorly swept (figure 15-21A) (Amateis and Hall, 1997). The extensive horizontal drilling program in Greater Aneth, described previously, also changed the five-spot flow pattern to line-drive injection patterns (figure 15-21B) and improved both areal and vertical sweep efficiencies over vertical wells (Amateis and Hall, 1997). Production and injection laterals are drilled into the Desert Creek porosity zones to sweep oil that vertical wells could not reach. Horizontal laterals are drilled in opposing, northwest and southeast directions, offset about 1800 feet (550 m) diagonally to parallel horizontal producing wells (figure 15-21B). This allows the line-drive flow to maintain reservoir pressure and more uniformly sweep oil from injection to producing wells (figure 15-21B) (Amateis and Hall, 1997). In addition, every other row of wells is left as vertical wells, resulting in significant cost savings and providing a method to produce or inject into units not horizontally drilled.

Amateis and Hall (1997) estimate a 5 to 10% increase in recovery of the OOIP using the line-drive flow pattern based on reservoir simulation. Modified versions of the line-drive flow pattern could be used on smaller fields in the Paradox Basin.

Carbon Dioxide Floods

Carbon dioxide (CO_2) flooding is a major enhanced oil recovery technique in mature West Texas fields (over 20% of that area's production) and elsewhere. However, only one field in Utah (and in the Paradox Basin) is under CO_2 flood – Greater Aneth. Carbon dioxide flooding is relatively low risk, significantly increases oil recovery, and extends the life of a field by 20 to 30 years. After primary oil production has declined, CO_2 is injected into the reservoir to push (via miscible displacement) remaining oil to offsetting producing wells. Ultimate oil recovery may increase by over 40% with CO_2 flooding (8 to 16% due to CO_2 flooding alone) (Lambert and others, 1995). There have been great advances in CO_2 flooding technology and experience over the last 20 years, especially the application of horizontal drilling techniques. However, millions of barrels of oil are at risk of never being recovered in the Paradox Basin unless the smaller reservoirs are evaluated for potential CO_2 flooding.

Basic concepts: When CO_2 is injected into an oil reservoir, the CO_2 becomes miscible with the residual oil at high pressure through multiple contacts with the oil in the reservoir pore systems. The CO_2 behaves like a solvent, reducing the viscosity of the residual oil by vaporizing or extracting both the intermediate and higher molecular weight hydrocarbons. This process improves the relative permeability of the formation to the oil and increases bulk volume (Lambert and others, 1995). The CO_2 also swells the oil, increasing the oil saturation, which increases the oil relative permeability; the fraction of oil flowing in the reservoir system is higher. The CO_2 creates carbonic acid, particularly in carbonate reservoir rocks, when it mixes with formation water and may increase porosity and permeability. Pulses of water are often injected into the reservoir to help push the now mobile oil more easily toward production wells (figure 15-22). The method is called water-alternating-gas (WAG) injection. Proper management of a WAG injection on a well pattern by well pattern basis shortens response time, reduces CO_2 production, and keeps operating costs down. The CO_2 is later separated from the oil/CO_2 mixture and ultimately re-injected. Another technique is continuous CO_2 injection which yields a quicker response but increases CO_2 production rates and results in higher operating costs. It can also accelerate oil production sufficiently to compensate for the increase in those operating costs.

Screening criteria: Evaluating potential candidates in the Paradox Formation for CO_2 flooding involves several screening criteria. The most important criterion is that CO_2 miscibility needs to be attainable over a major portion of the reservoir, requiring widespread good injectivity and reservoir connectivity. Therefore, understanding reservoir lithofacies, heterogeneity, and petrophysical properties is critical in planning CO_2 flooding programs. The reservoir should be deeper than 2500 feet (760 m) and the API gravity of the oil greater than 25º (Hsu and others, 1995). The depth to the Ismay and Desert Creek zones generally ranges from 5320 to 5920 feet (1620-1800 m); the API gravity of Paradox Formation oils ranges from 38º to 53º. The maximum viscosity must be 10 to 12 centipoise (cP) (Lambert and others, 1995); the viscosity of Greater Aneth oil is 0.54 cP. Prospective CO_2 flooding candidates have performed well during waterflood programs where they established favorable sweep efficiency, acceptable throughput rates, and good voidage balance (Hsu and others, 1995).

Limiting factors to CO_2 flood programs include complex reservoir heterogeneity which can create non-uniform displacement fronts. In such a case, there may be an early breakthrough

in high-porosity/permeable units from the CO_2 sweep. However, residual oil may remain in the unswept, low-porosity/permeability units or as by-passed oil in compartments, which would require more CO_2 during the life of the flood and thus higher CO_2 costs per barrel of oil recovered and recycling expenses. The presence of gas caps (rare in the Paradox Formation fields), faulting, and dominant fracture systems (fracture-enhanced permeability) could result in CO_2 loss. Loss of CO_2 into these "thief" zones also leads to higher CO_2 purchase cost per barrel recovered and greater cycle expenses such as cement squeeze jobs, and use of foam and polymers as part of workover efforts. If production water cut reaches 98%, especially during waterfloods, operators likely lose the ability to borrow capital against future production and CO_2 flooding becomes uneconomic (Lambert and others, 1995). In addition, operating expenses per barrel also increase tremendously as a result of the greater volume of water to dispose during the program.

Carbon dioxide sources and gas plants: A reliable source of CO_2 must be available, obviously, for long-term CO_2 flooding programs. The Devonian Ouray Formation and Mississippian Leadville Limestone, at McElmo Dome field on the eastern edge of the Paradox Basin in southwest Colorado, supply CO_2 to Greater Aneth field (and Permian Basin fields) via an 8-inch pipeline (figure 10-4). McElmo Dome field produces nearly pure CO_2 with reserves estimated at 2.5 trillion cubic feet (71 billion m^3) of gas (Tremain, 1993). With only the one pipeline in the Paradox Basin, sources of CO_2 may have to be obtained by drilling. Several in-field exploratory wells (at Bluff, Desert Creek, Gothic Mesa, and Deadman Canyon fields for example [figure 10-4]) have tested gas containing CO_2 concentrations of 80% or higher from the Ouray and Leadville (Chidsey and Morgan, 1993). Pipeline permitting problems in this environmentally sensitive and rugged region and high costs make drilling for CO_2 locally a viable option. It is also important to recognize that CO_2 prices fluctuate in response to crude oil prices.

Another potential source of CO_2 is emissions from coal-fired power plants. Plants in Utah and those surrounding the Paradox Basin emit 66 to 87 million tons of CO_2 per year (Allis, 2003) (figure 15-23). If the CO_2 is removed and "captured" from the combustion exhaust at these sites, it could be transported via pipeline (using current pipeline rights-of-way) to maturing Paradox Basin oil fields for CO_2 flooding programs (figure 15-24). Once these programs reach their economic limit, the CO_2 could be permanently and safely stored (sequestered) geologically in the reservoirs, helping to reduce global warming.

High volumes of natural gas liquids (NGL) in the produced gas stream require processing where the CO_2 is stripped from the NGL and then reinjected (Lambert and others, 1995). Dehydrating the gas stream using an absorption/stripping process, then compressing and recycling the gas, is often more economic (Lambert and others, 1995). The close proximity of a gas plant and its processing capabilities are significant factors in planning CO_2 flooding programs, gas transmission being more expensive than processing. The McElmo Creek unit at Greater Aneth has a large gas plant (figure 15-25), whereas other fields in the basin have no gas plants.

Reservoir modeling and simulation to plan carbon dioxide flooding programs: As with waterflooding programs, reservoir 3-D modeling and compositional simulation should be major components in designing CO_2 flooding programs for both large and small Paradox Formation fields to predict CO_2 flood performance. Parasequence boundaries must be incorporated into

reservoir models to yield accurate simulation results. Well patterns and reservoir "sweet spots" can be determined to reduce risk and the time required for implementation.

Culham and Lorenz (2003a, 2003b) selected two small fields, Anasazi and Runway, peripheral to Greater Aneth (figure 10-4), for geostatistical modeling and reservoir compositional simulations. The reservoirs of these two fields consist of phylloid-algal buildups with a mound-core interval and a supra-mound interval. Hydrocarbons are stratigraphically trapped in porous and permeable lithotypes within the mound-core intervals of the lower part of the buildups and the more heterogeneous supra-mound intervals. The models and simulations incorporated variations in carbonate lithotypes, porosity, and permeability to accurately predict reservoir responses. History matches tied previous production and reservoir pressure histories so that future reservoir performances could be confidently predicted.

The simulation studies showed that despite most of the production being from the mound-core intervals, there were no corresponding decreases in the oil in place in these intervals. This behavior indicates gravity drainage of oil from the supra-mound intervals into the lower mound-core intervals from which the producing wells' major share of production arises. The key to increasing ultimate recovery from these fields (and similar fields in the basin) is to design either waterflood or CO_2-miscible flood projects capable of forcing oil from high-storage-capacity, but low-recovery, supra-mound units into the high-recovery mound-core units. Simulation of Anasazi field shows that a CO_2 flood is technically superior to a waterflood and economically feasible. For Anasazi field, an optimized CO_2 flood is predicted to recover a total 4.21 million bbls (0.67 million m^3) of oil representing in excess of 89% of the OOIP. For Runway field, the best CO_2 flood is predicted to recover a total of 2.4 million bbls (0.38 million m^3) of oil representing 71% of the OOIP. If CO_2 flooding performs as predicted, it is a financially robust process for increasing the reserves in the many small fields in the Paradox Basin.

McElmo Creek unit carbon dioxide flood, Greater Aneth field: Carbon dioxide flooding began in the McElmo Creek unit of Greater Aneth in 1985. The production response was between one and two years through a WAG program. Oil production increased from 5500 BOPD to 6500 BOPD (880-1030 m^3/d) peaking after a ten-year period (Lambert and others, 1995). Therefore, a long-term commitment is required to meet production goals. The McElmo Creek unit consists of about 90 producing, 65 WAG injection, 30 water injection, 49 idle, and nine water supply wells (Rudy Smith, ExxonMobil Production, verbal communication, June 22, 2004). In 2006, the 4.8 BCFG (0.14 billion cubic m^3) of CO_2 was injected into the reservoir by vertical wells (Utah Division of Oil, Gas and Mining, 2006); the injection pressure is about 3000 psi (20,700 kPa). All gas is reinjected into the reservoir; the McElmo Creek unit gas plant has four compressors (figure 15-25) and the water injection plant has two pumps. The McElmo Creek unit has produced over 154 million bbls (25 million m^3) of oil (Utah Division of Oil, Gas and Mining, 2008) of the 459 million bbls (73 million m^3) of the OOIP (Jim Rutledge, Los Alamos National Laboratory, verbal communication, July 26, 2007). Incremental recovery from CO_2 flooding is estimated at 33 million BO (5.3 million m^3) or an incremental recovery efficiency of 9.3% (Jim Rutledge, Los Alamos National Laboratory, verbal communication, July 26, 2007). Future plans for the McElmo Creek unit may include fracturing existing producers, nitrogen cleanouts, and additional CO_2 flooding of various previously unflooded lithologic intervals (Rudy Smith, ExxonMobil Production, verbal communication, June 22, 2004).

A pilot CO_2 flood using horizontal wells (lateral) was conducted in the eastern part of the Aneth unit in 1998. The horizontal laterals were drilled in vuggy, phylloid-algal dolomitic bafflestone. Although the project was brief, rapid CO_2 breakthrough occurred after which it was abandoned. Resolute Natural Resources is the current field operator and has initiated a major CO_2 flood program in the unit utilizing horizontal wells based on 3-D modeling and simulation. The best intervals for CO_2 flooding are not phylloid-algal bafflestone but oolitic grainstone and packstone. Small southwest-northeast-trending faults and associated fracture zones are common in the Aneth unit. As described previously, northwest-southeast-directed horizontal wells perpendicular to the fault/fracture zones have successfully increased production in the unit. However, those horizontal well orientations could lead again to early CO_2 breakthrough. Therefore, the best options for a successful CO_2 flood are either vertical wells or horizontal laterals oriented parallel to the fault/fracture zones.



Figure 15-1. Lisbon field gas processing plant, oil and natural gas liquid storage tanks, and incinerator (one of two).

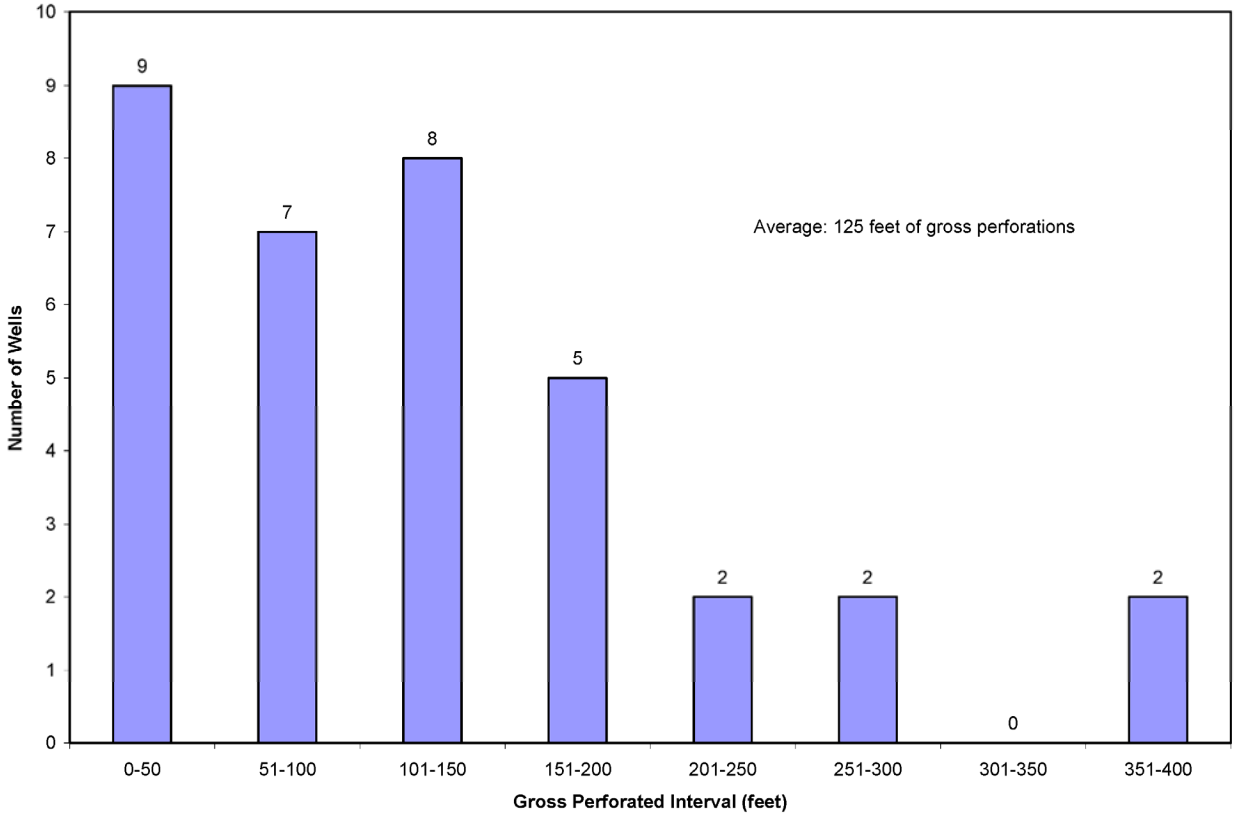


Figure 15-2. Thickness of gross perforated intervals in Lisbon field wells, in feet.

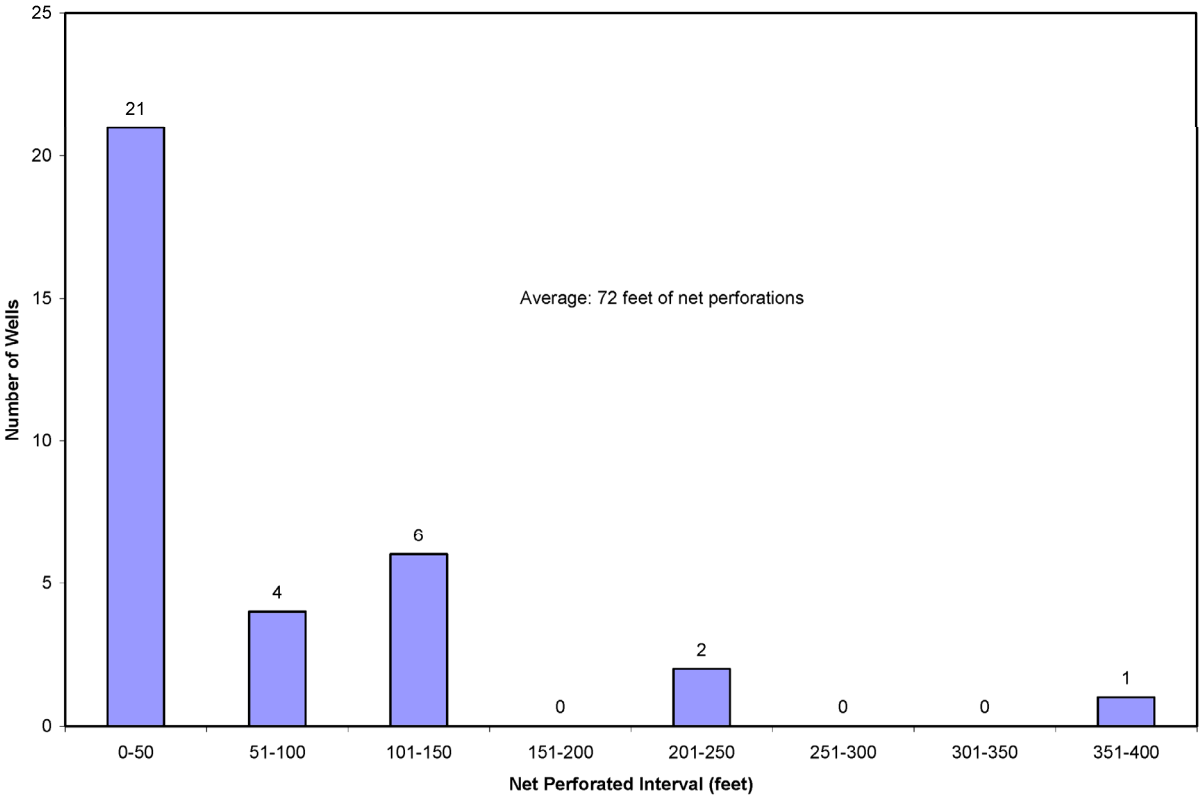


Figure 15-3. Thickness of net perforated intervals in Lisbon field wells, in feet.

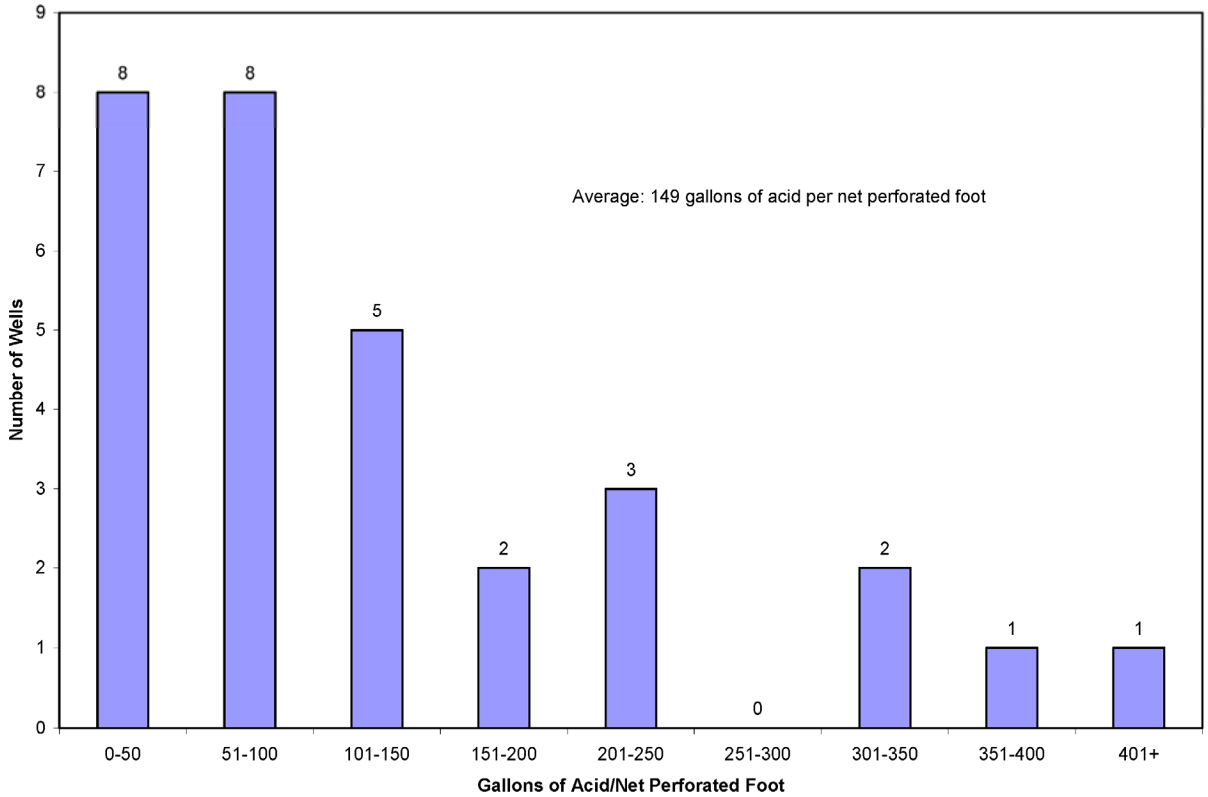


Figure 15-4. Gallons of acid per foot of perforation used to stimulate Lisbon field wells.



Figure 15-5. Typical Lisbon well site including: A – wellhead, B - tank batteries, C – dehydrators with chemical storage tank for methanol, D – heated separators (heater/treaters), E – double-walled emergency pit tanks, and F – solar-powered flow meters.

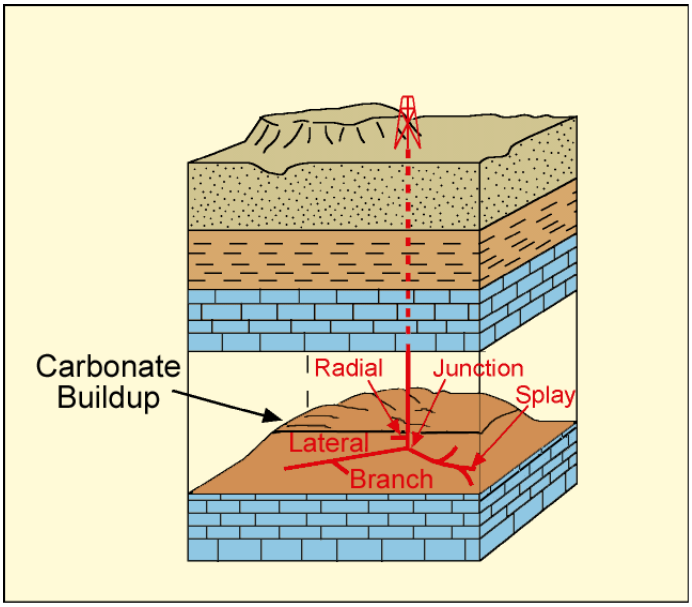


Figure 15-6. Definitions associated with a multilateral well targeting a carbonate buildup. Modified from Chambers (1998).

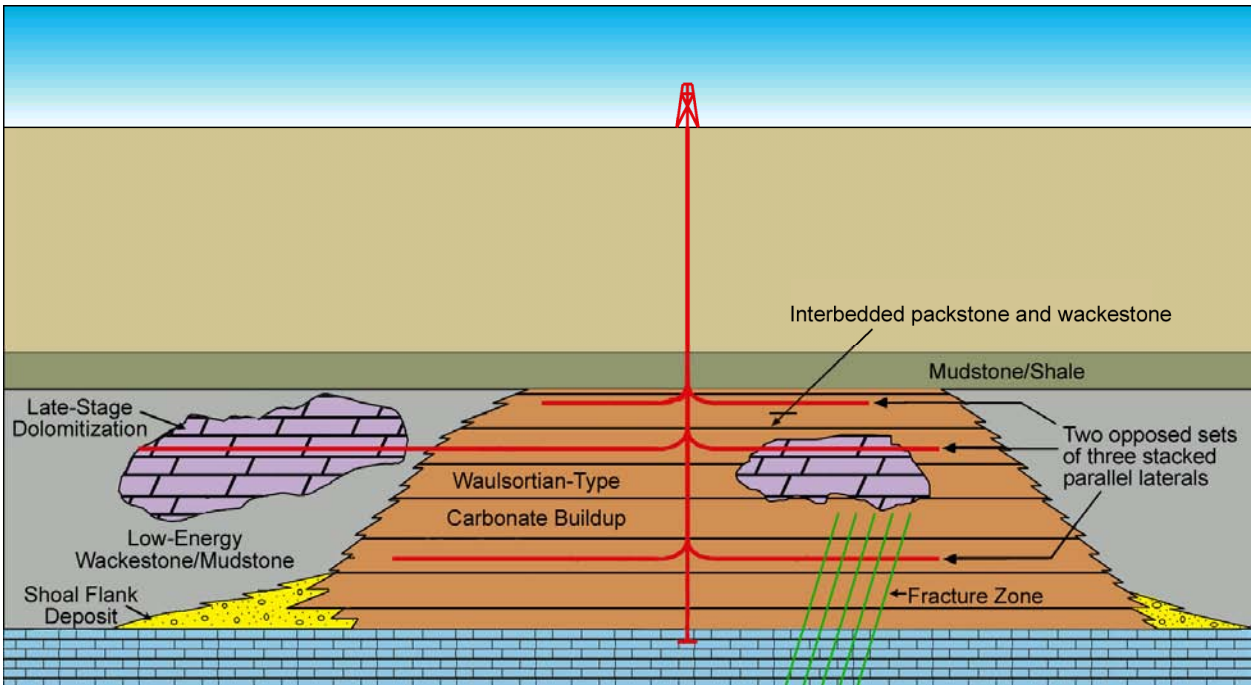


Figure 15-7. Schematic diagram of drilling targets in a Mississippian Waulsortian mound facies by multilateral (horizontal) legs from an existing field well.

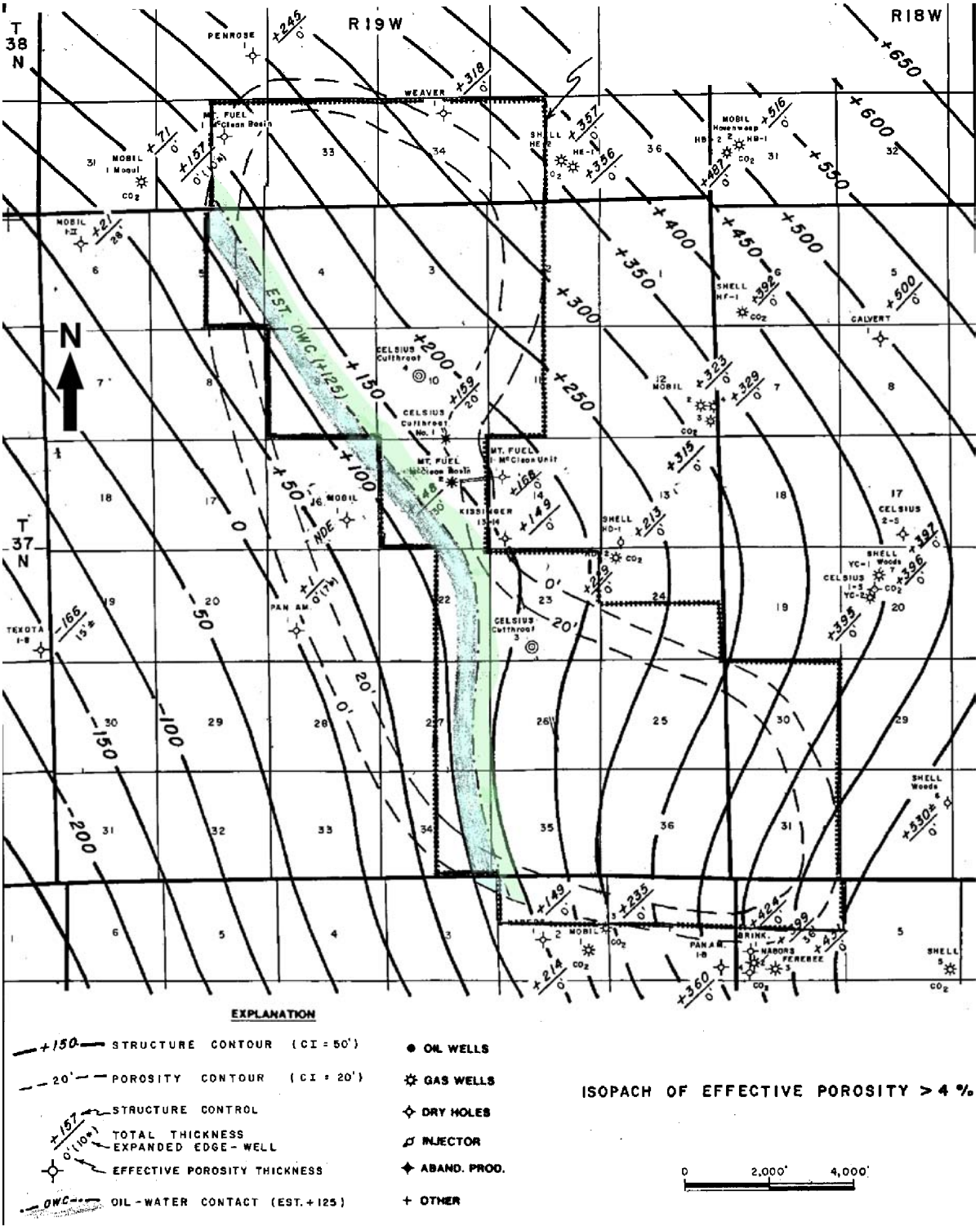


Figure 15-8. Combined top of Desert Creek zone structure and effective porosity map, McClean field, Montezuma County, Colorado (after Colorado Oil and Gas Conservation Commission, 1985a).

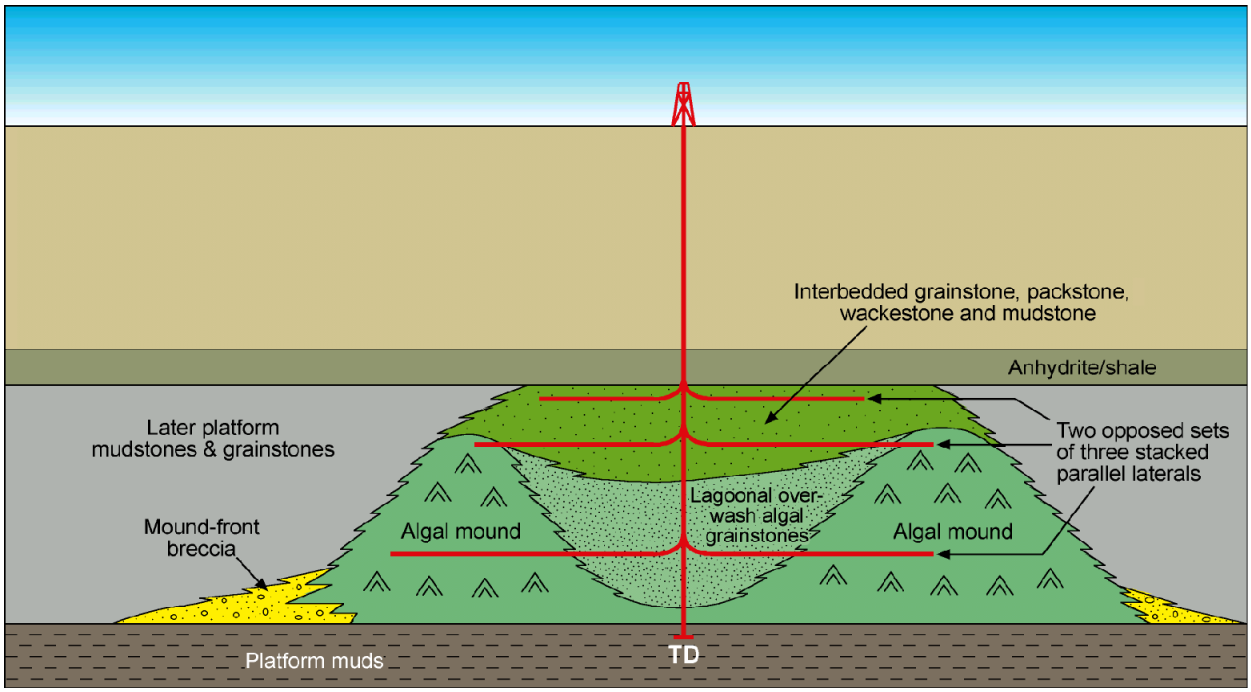


Figure 15-9. Schematic diagram of Ismay zone drilling targets by multilateral (horizontal) legs from an existing field well.

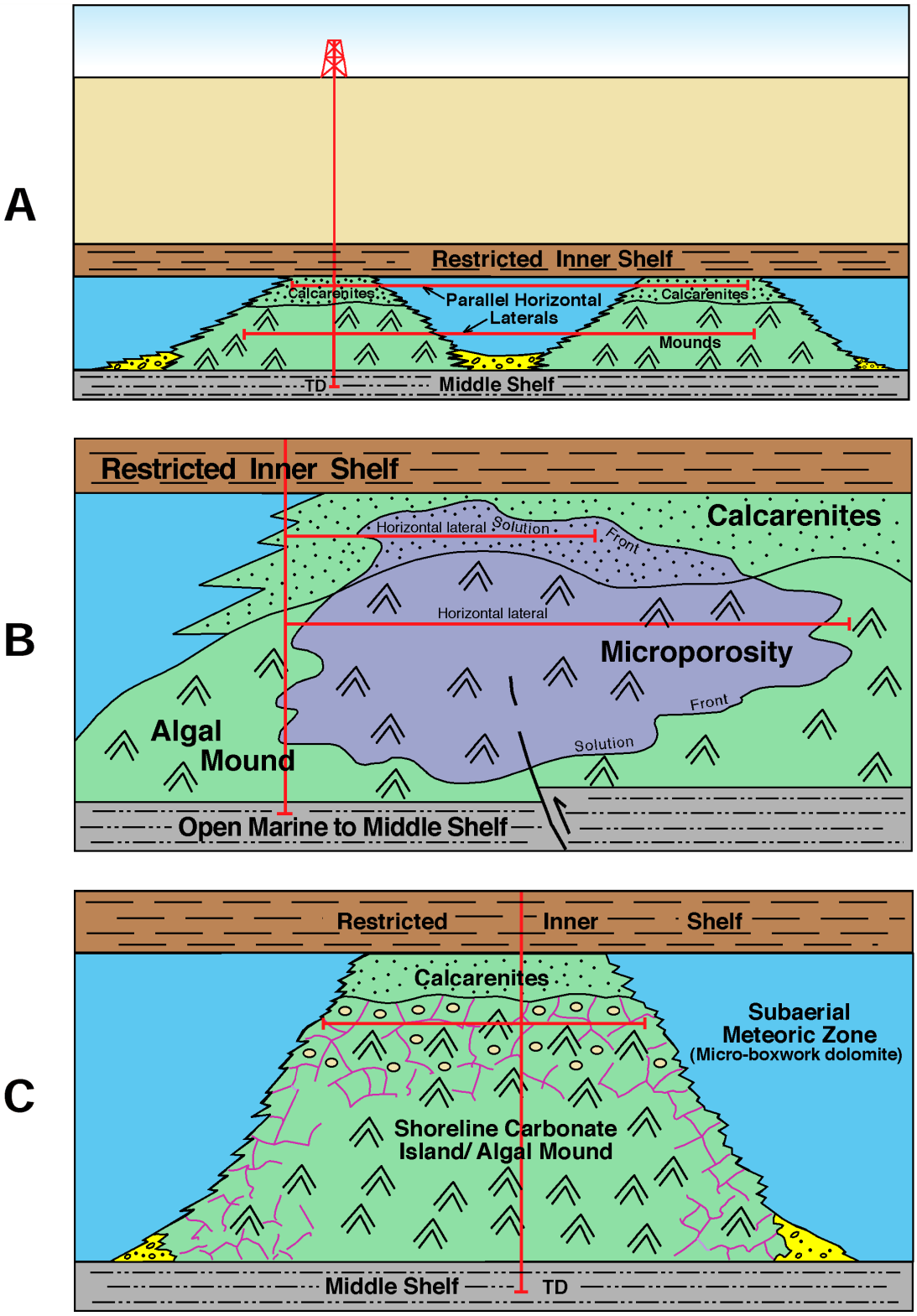


Figure 15-10. Schematic diagram of strategies for horizontal drilling for Desert Creek and Ismay fields in the Blanding sub-basin subplays: (A) depositional lithofacies in the Ismay and Desert Creek zones, (B) microporosity in the Ismay zone, and (C) depositional lithofacies and diagenetic fabrics (micro-boxwork porosity) in the Desert Creek zone.

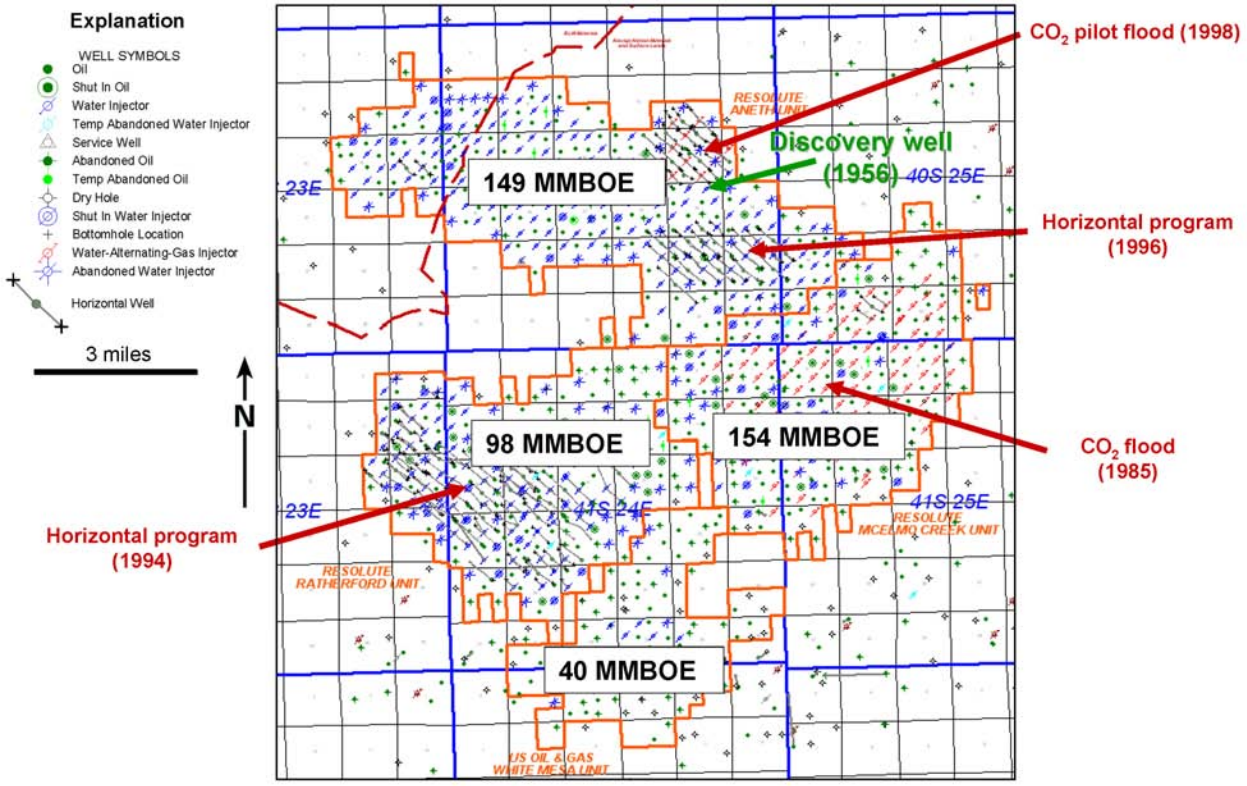


Figure 15-11. Best practices and cumulative production, Greater Aneth field, Utah. After Resolute Natural Resources unpublished map (2007).

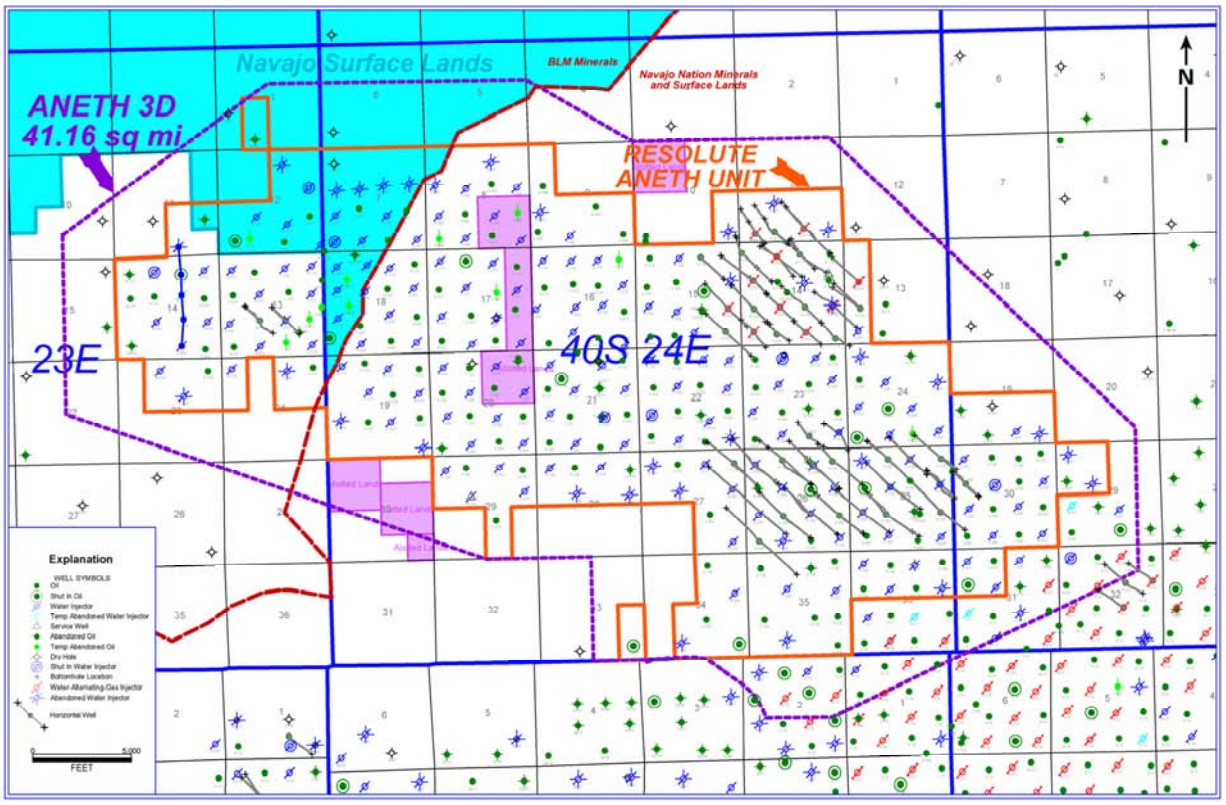


Figure 15-12. Base map of well types and horizontal well orientations in the Aneth unit, Greater Aneth field. After Resolute Natural Resources unpublished map (2007).

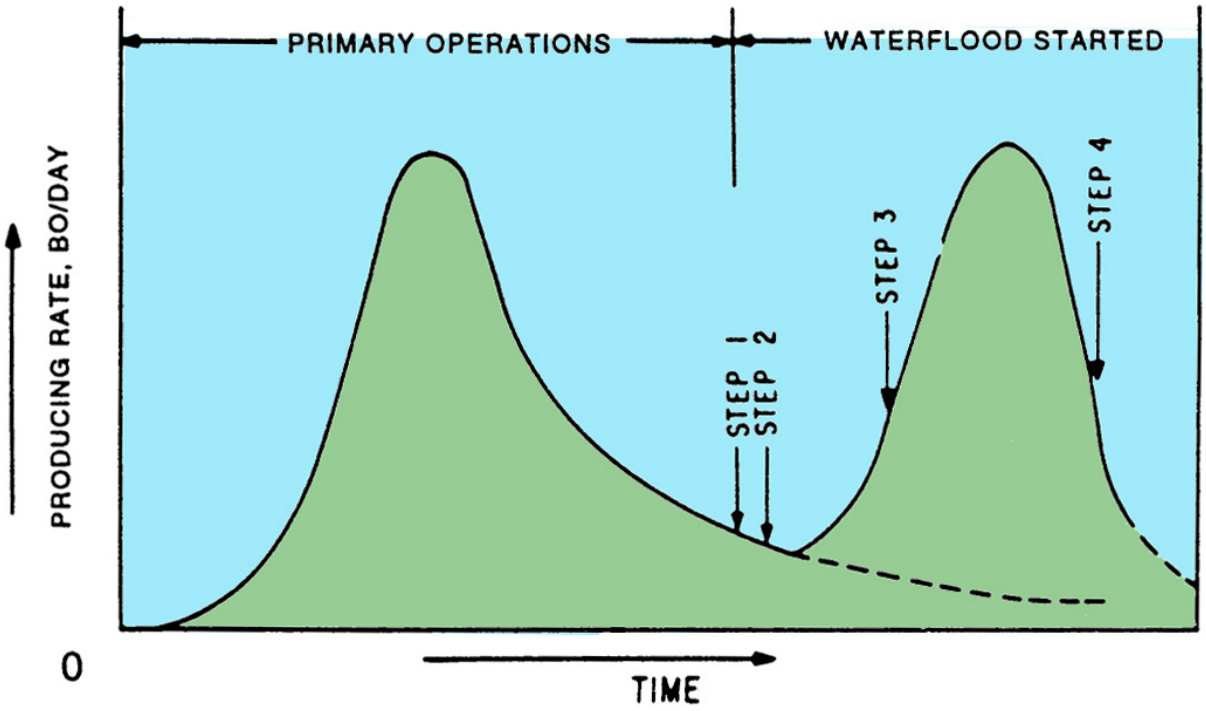


Figure 15-13. Primary and secondary production curves for a solution gas reservoir. After Clark (1969).

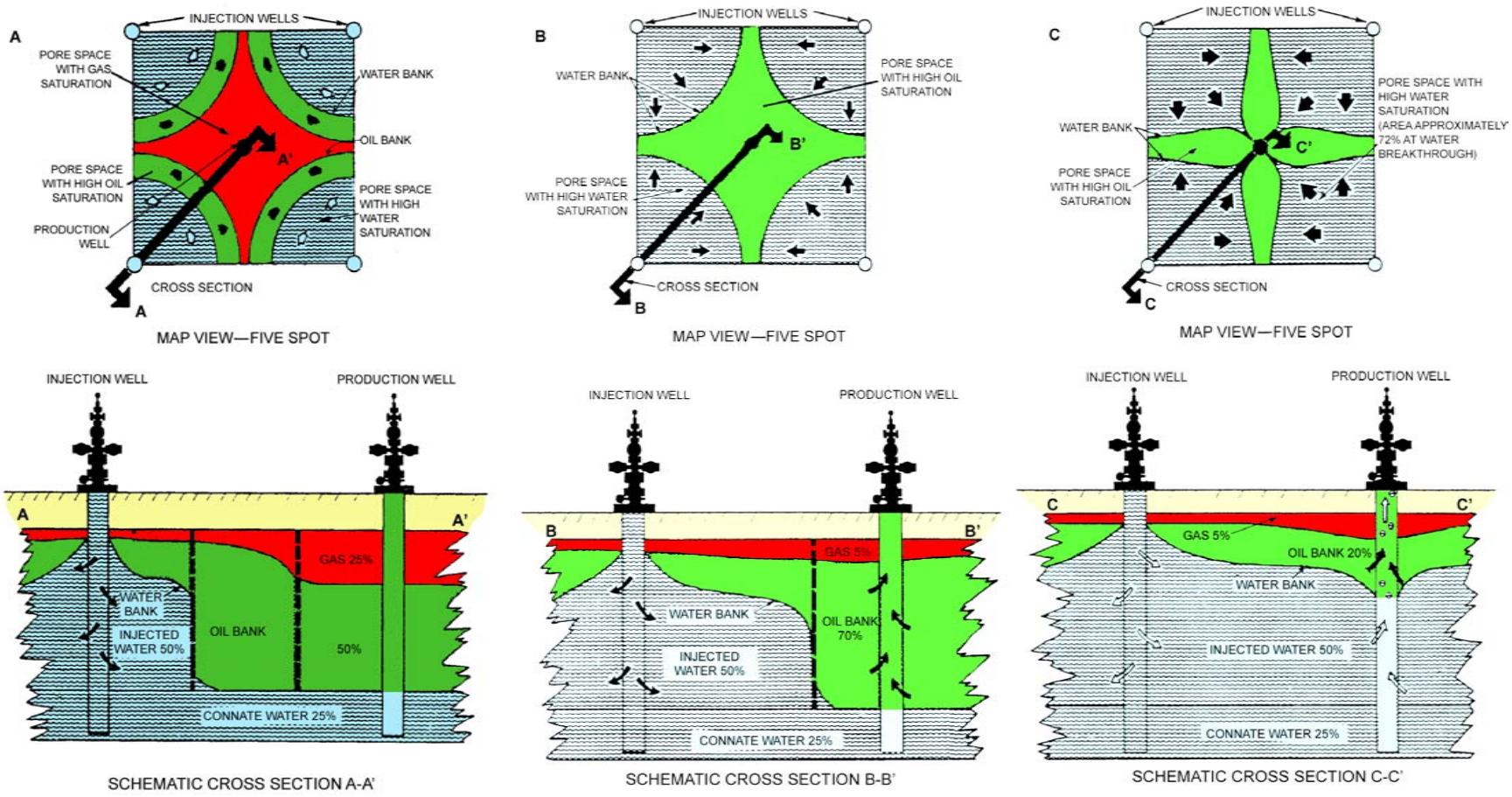


Figure 15-14. Areal (top) and cross section (bottom) of a five-spot well pattern under waterflood injection for a solution gas reservoir. A – Development of an oil bank in front of a water bank; step 2 of the production curve shown on figure 15-13. B – Major increase in oil production at fill-up; step 3 of the production curve shown on figure 15-13. C – Water breakthrough when the water bank reaches the wellbore; step 4 of the production curve shown on figure 15-13. Modified from Clark (1969).

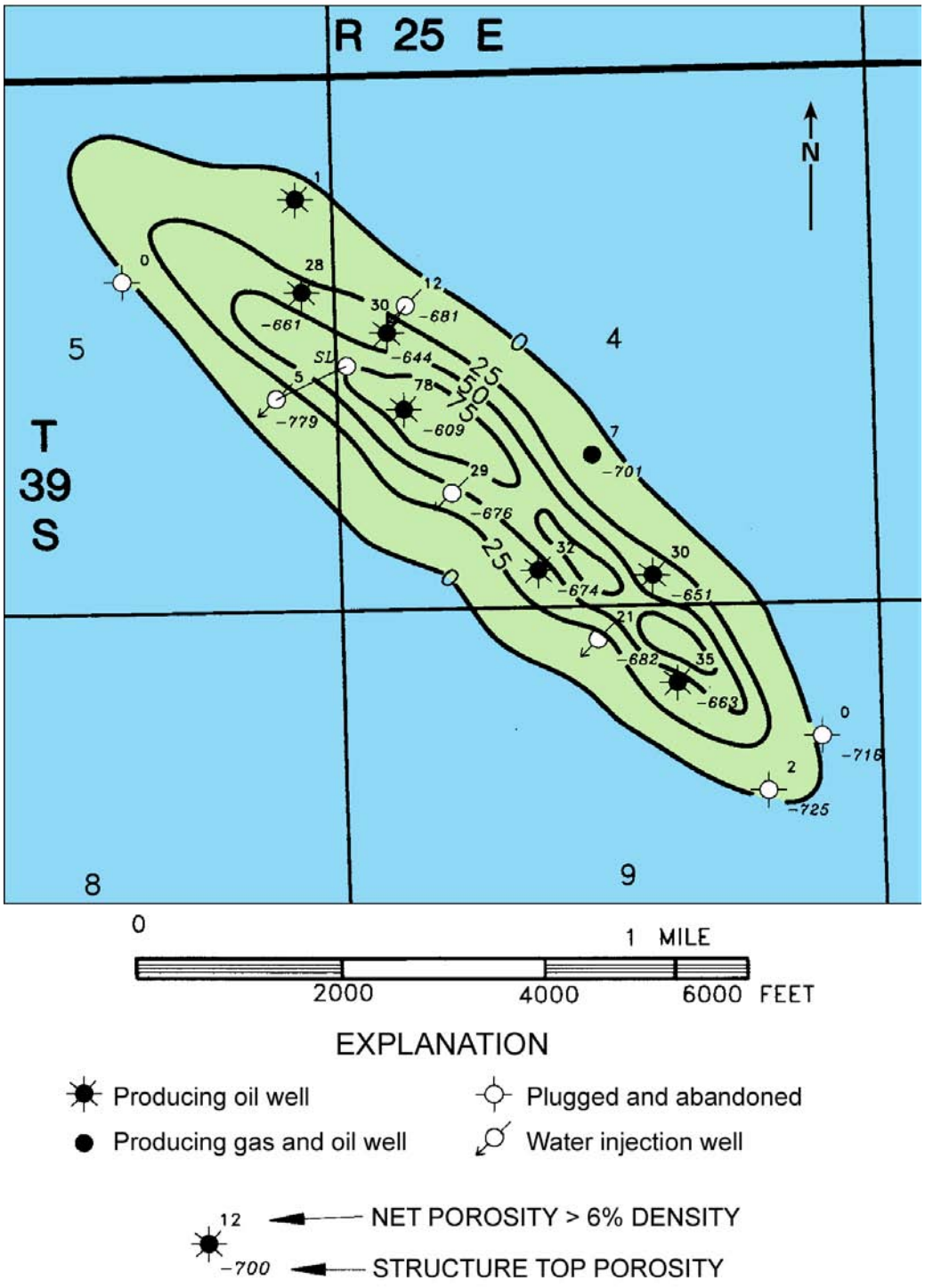


Figure 15-15. Upper Ismay zone isopach map, Kiva field; contour interval = 25 feet. After Crawley-Stewart and Riley (1993a).

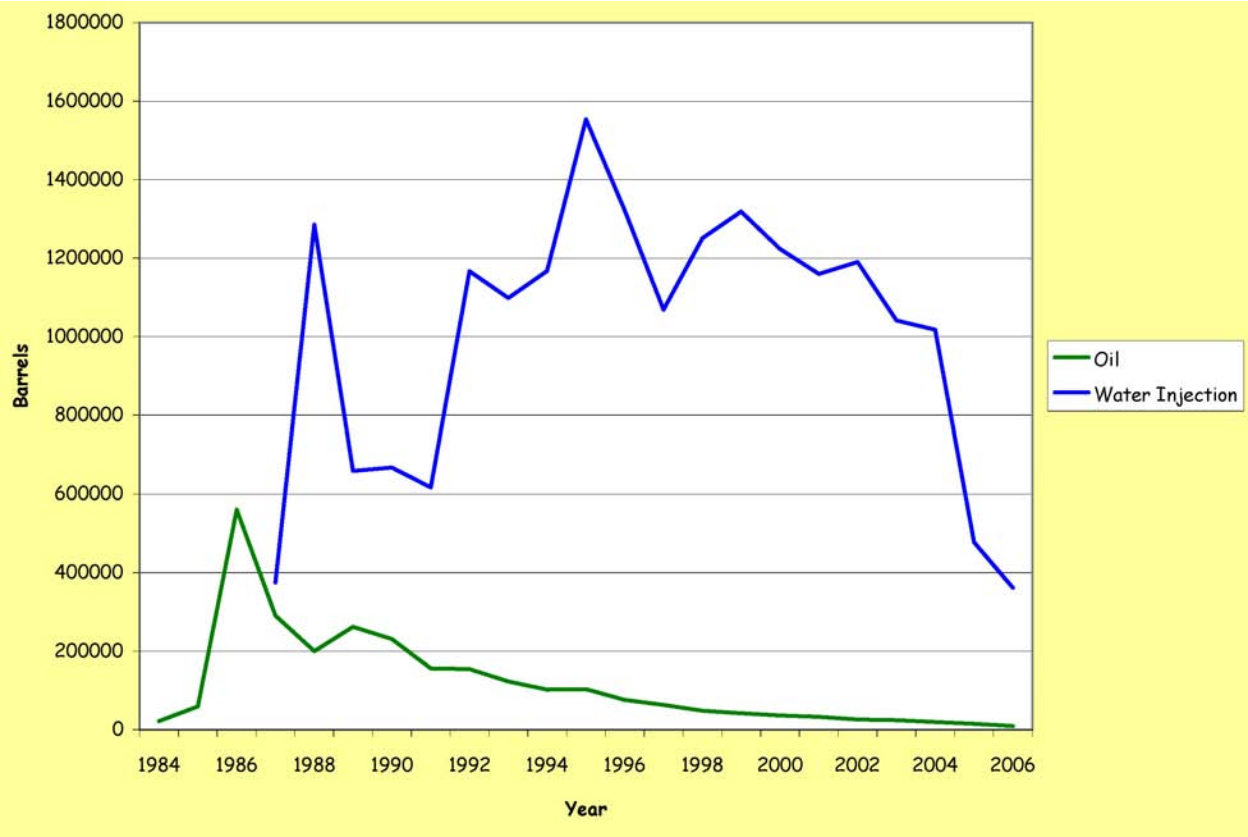


Figure 15-16. Production and water injection history, Kiva field. Data source: Utah Division of Oil, Gas and Mining, 2006.

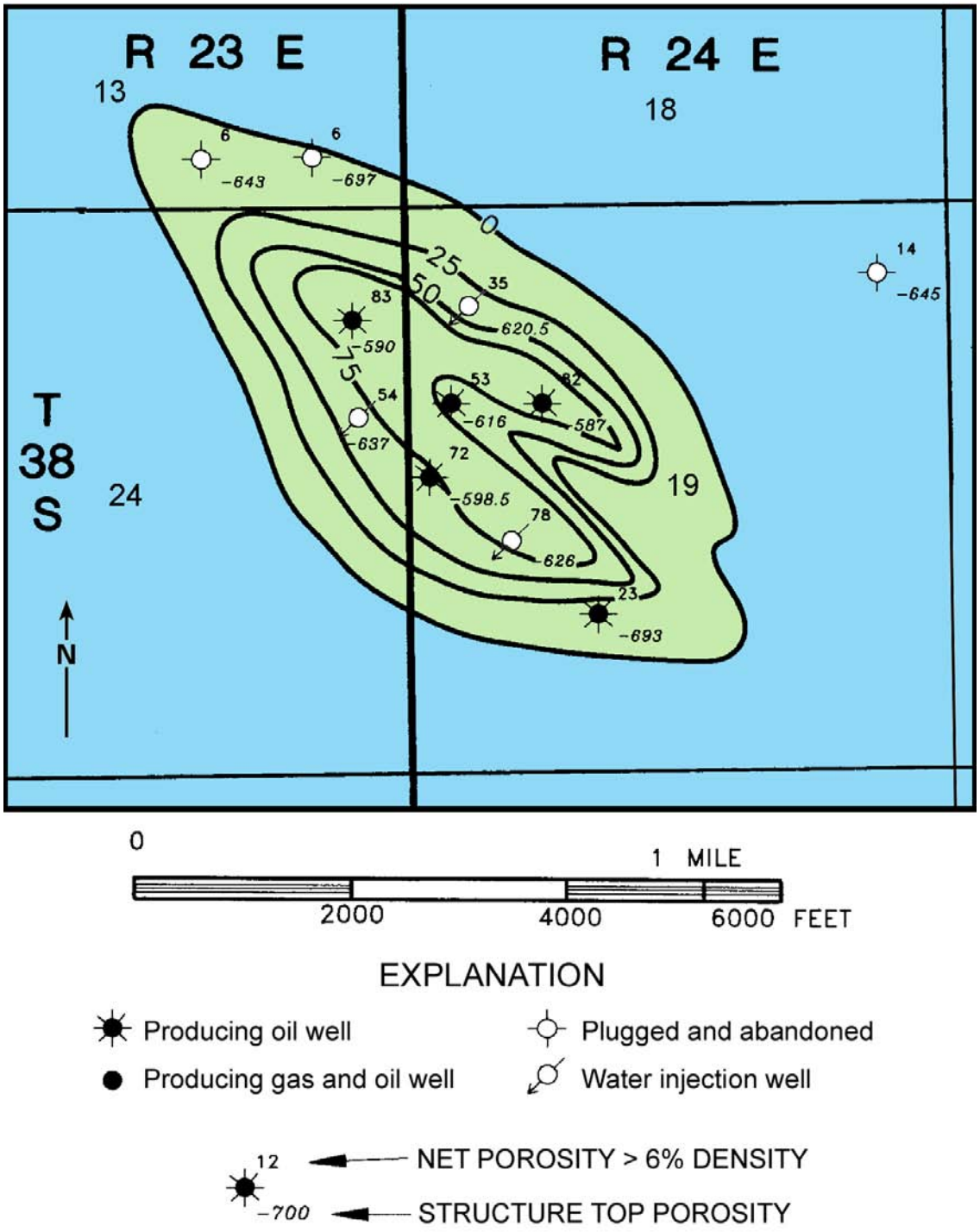


Figure 15-17. Upper Ismay zone isopach map, Kachina field; contour interval = 25 feet. After Crawley-Stewart and Riley (1993b).

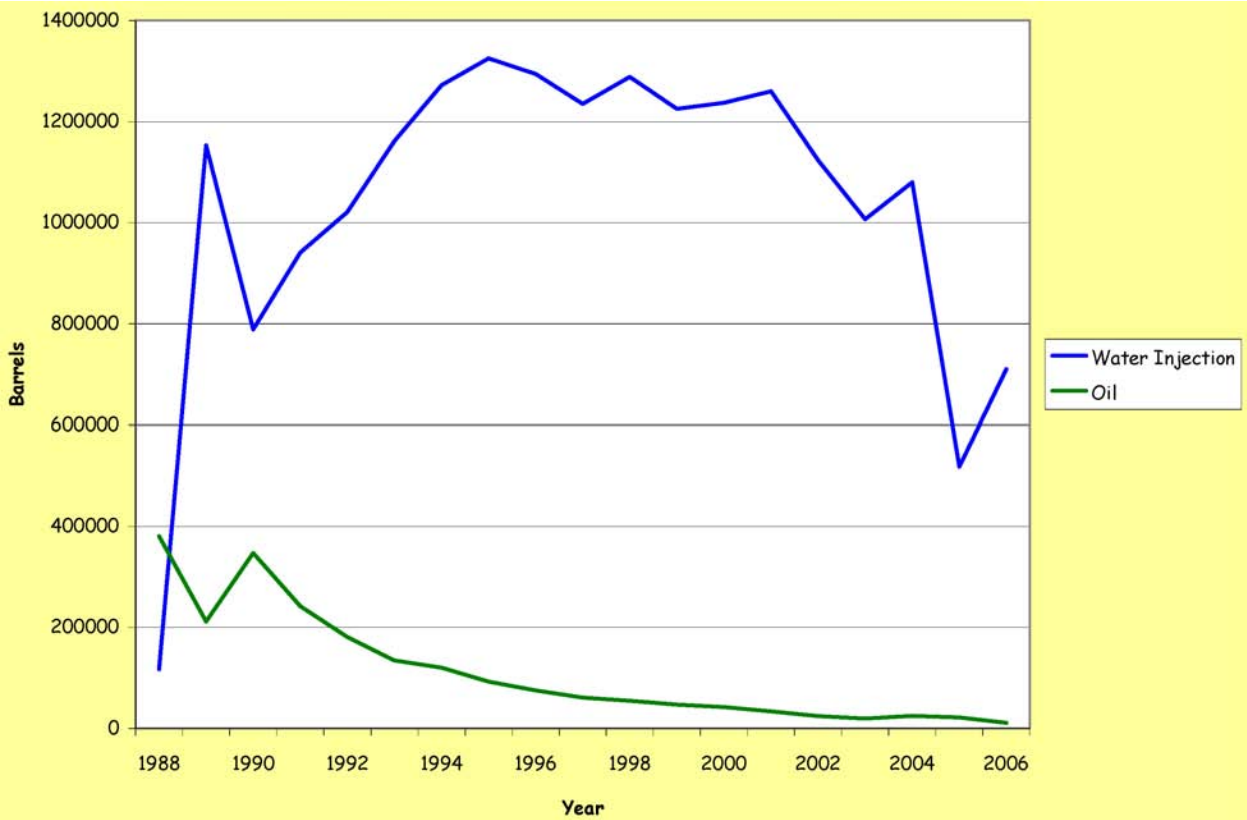


Figure 15-18. Production and water injection history, Kachina field. Data source: Utah Division of Oil, Gas and Mining, 2006.

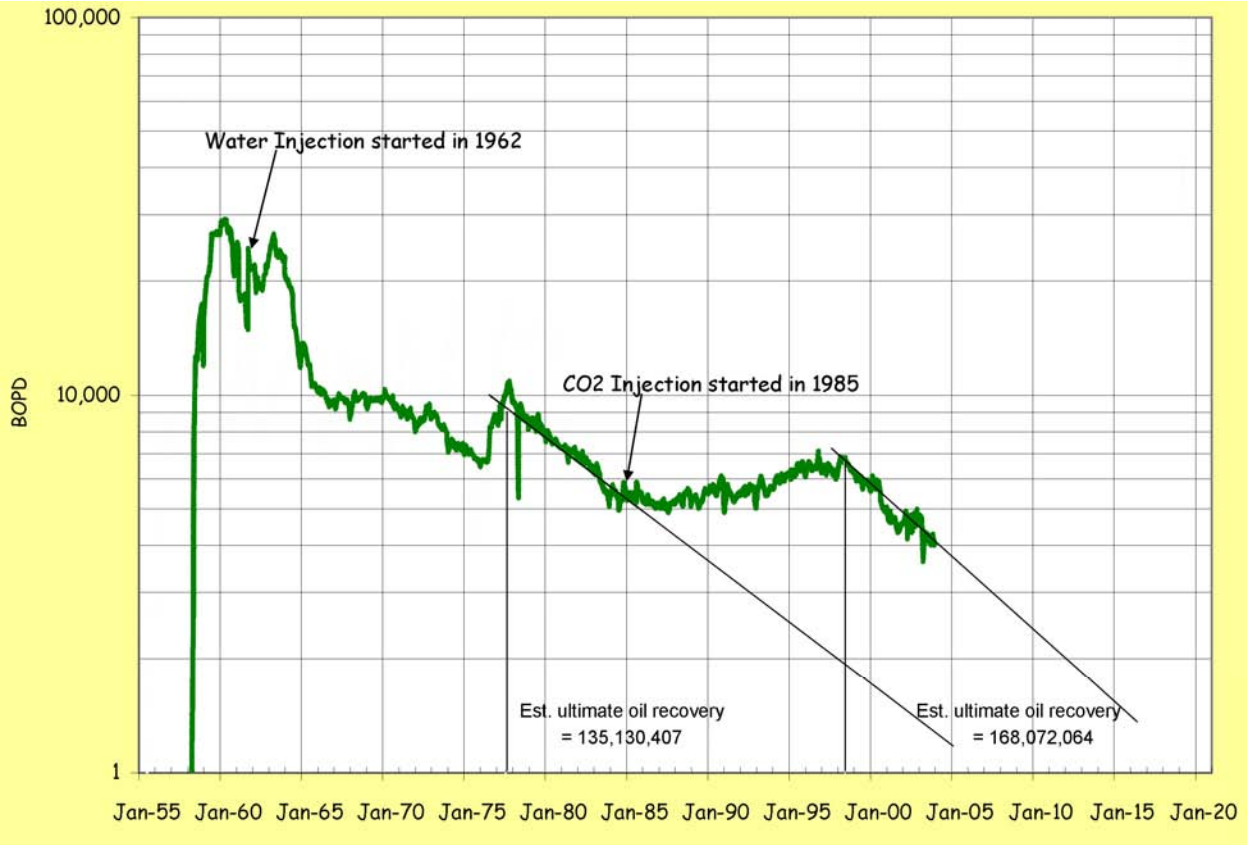


Figure 15-19. Oil production history from the McElmo Creek unit which uses only vertical wells for its waterflood and CO_2 flooding projects, Greater Aneth field. After Resolute Natural Resources unpublished graph (2007).

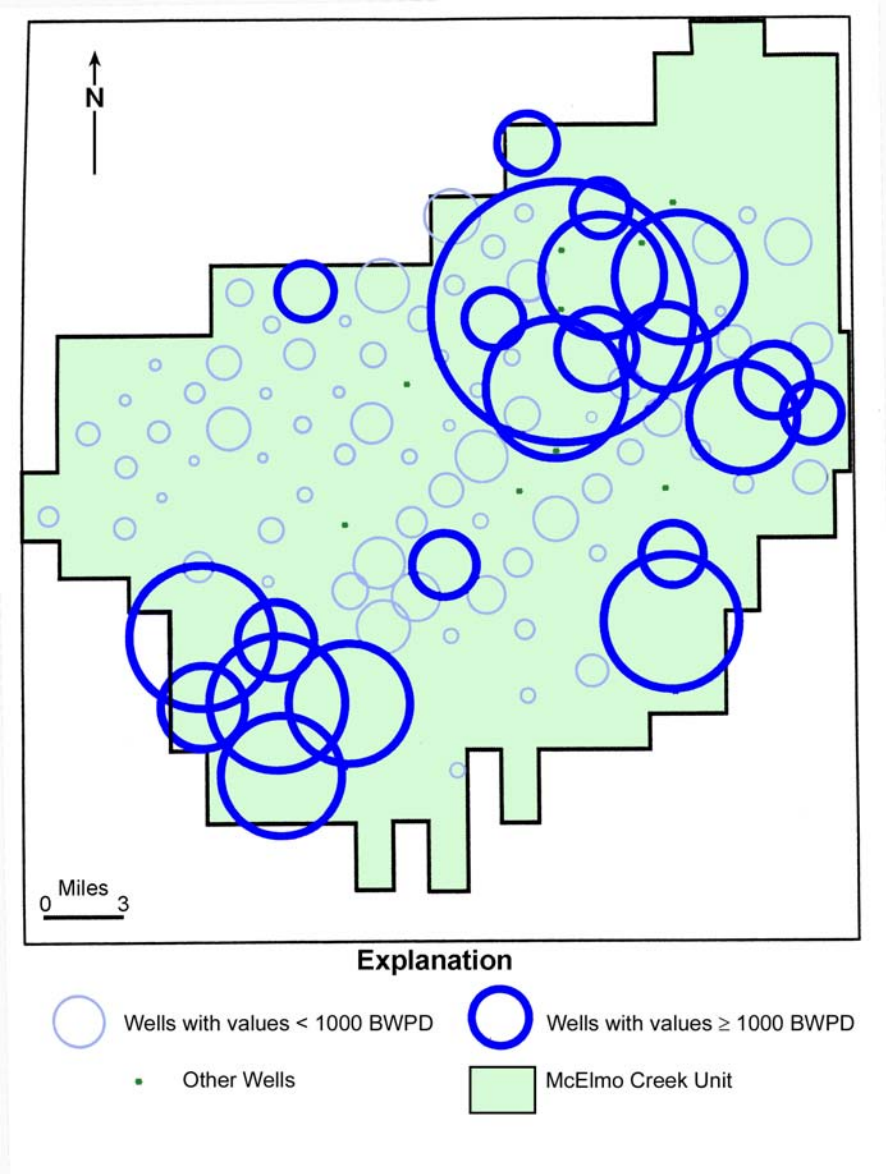


Figure 15-20. Maximum daily Desert Creek zone water injection rate map showing volumes in bbls of water per day (BWPD), McElmo Creek unit, Greater Aneth field. After Weber and others (1995b).

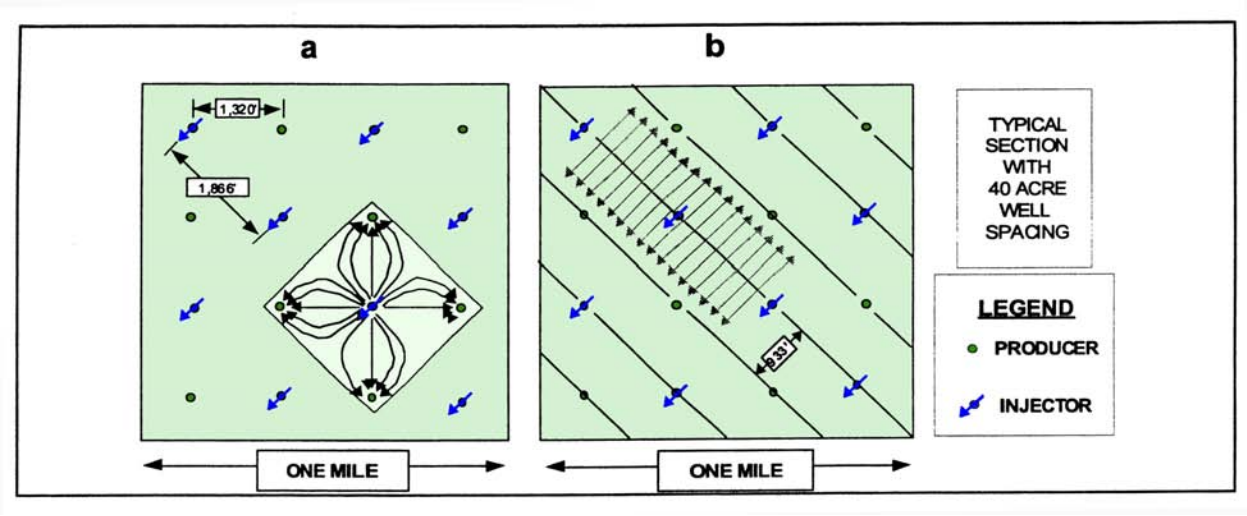


Figure 15-21. Waterflood flow patterns at Greater Aneth field. A – Vertical wells in a five-spot radial flow pattern. B – Line-drive flow pattern using horizontal wells. After Amateis and Hall (1997).

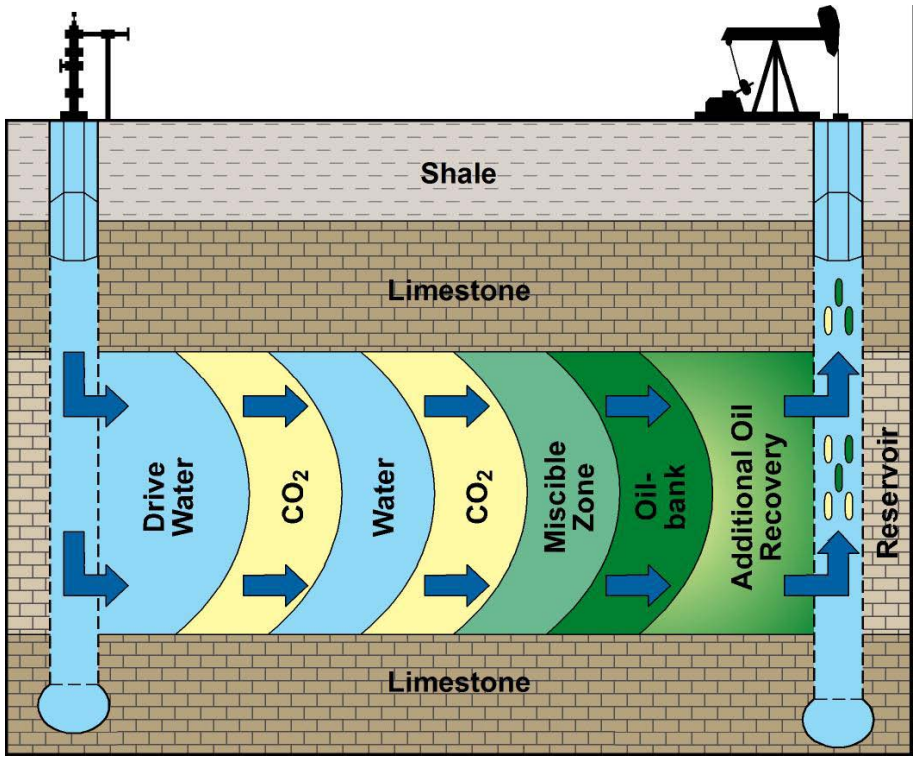


Figure 15-22. Schematic diagram showing water-alternating-gas (WAG) CO_2 injection.

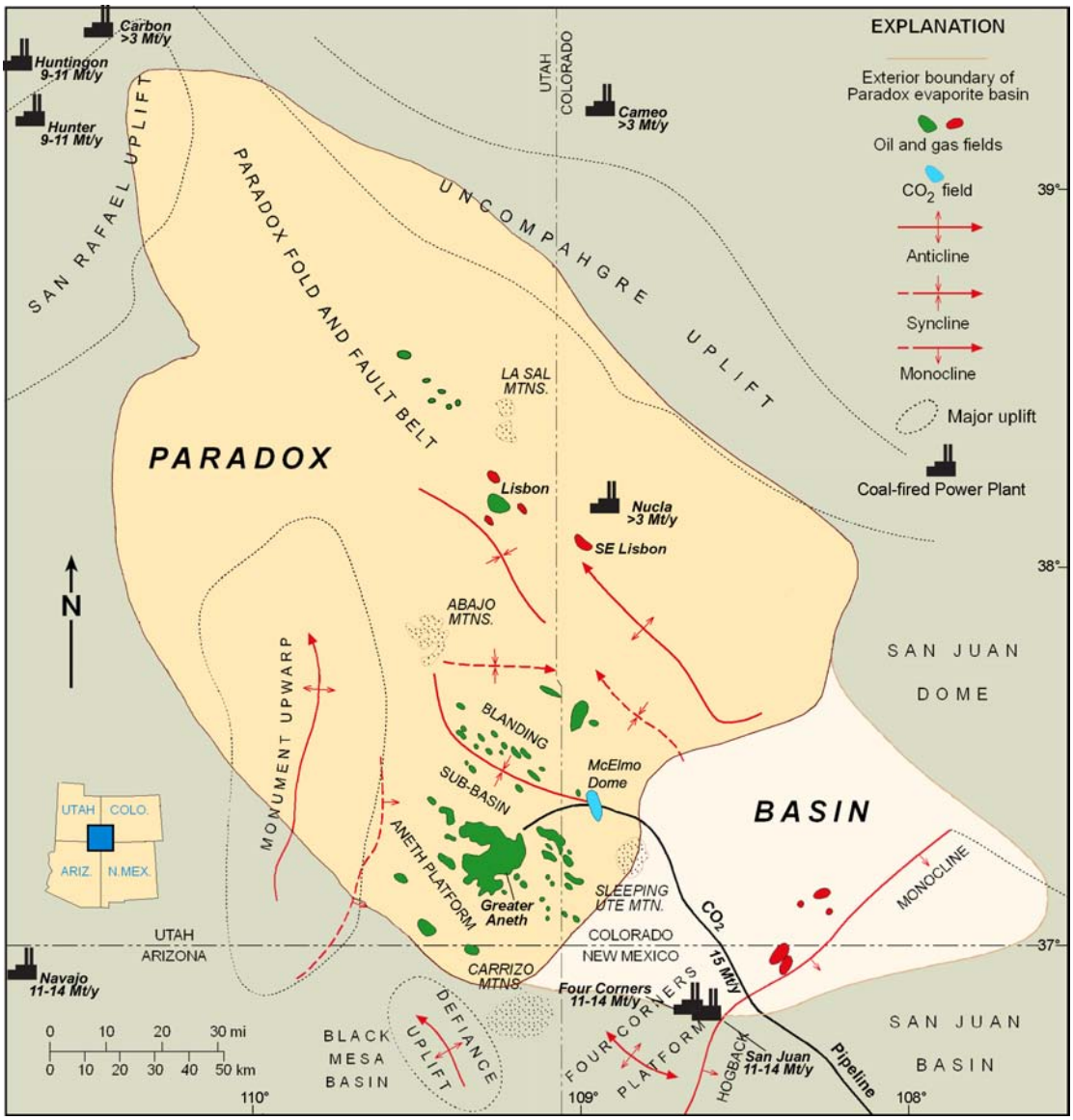


Figure 15-23. The locations of and emissions from surrounding coal-fired power plants (Mt/y = million tons of CO_2 per year), and oil and gas fields in the Paradox Basin of Utah, Colorado, and Arizona (modified from Harr, 1996). Colored (light orange) area shows present and potential of play area in the Paradox Basin.

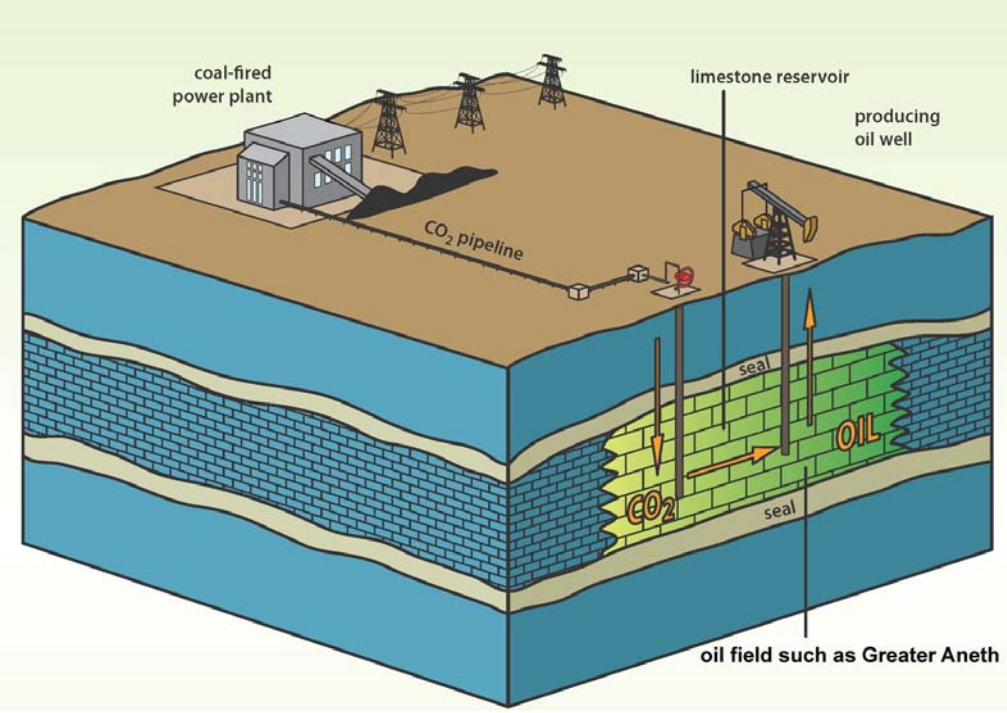


Figure 15-24. Schematic diagram showing possible future system of capturing and transporting CO_2 from a coal-fired power plant for use in a CO_2 flooding project for enhanced oil recovery and ultimate permanent storage in a mature oil field like Greater Aneth.



Figure 15-25. The McElmo Creek unit gas plant at Greater Aneth field.

CHAPTER 16 – SUMMARY AND CONCLUSIONS

Thomas C. Chidsey, Jr.,
Utah Geological Survey

Utah contains large areas that are still virtually unexplored. There is also significant potential for increased recovery from existing fields by employing improved reservoir characterization and the latest drilling, completion, and enhanced oil recovery technologies. A combination of depositional and structural events created the right conditions for oil generation and trapping in the major oil-producing provinces (thrust belt, Uinta Basin, and Paradox Basin) in Utah and adjacent areas in Colorado, Wyoming, and Arizona. Oil plays are specific geographic areas having petroleum potential due to favorable source rock, migration paths, reservoir characteristics, and other factors.

Major Oil Plays

Jurassic Nugget Sandstone Thrust Belt Play

1. The most prolific oil play in the Utah/Wyoming thrust belt province is the Jurassic Nugget Sandstone thrust belt play, having produced over 288 million bbls (46 million m^3) of oil and 5.1 TCFG (145 billion m^3). The Nugget Sandstone was deposited in an extensive dune field that extended from Wyoming to Arizona. Playas, mudflats, or oases developed in interdune areas. Traps form on discrete subsidiary closures along major ramp anticlines where the Nugget is extensively fractured. The seals for the producing horizons are overlying argillaceous and gypsiferous beds within the Jurassic Twin Creek Limestone, or a low-permeability zone at the top of the Nugget Sandstone.

2. Hydrocarbons in Nugget Sandstone reservoirs were generated from subthrust Cretaceous source rocks. The source rocks began to mature after being overridden by thrust plates. Hydrocarbons were then generated, expelled, and subsequently migrated into overlying traps, primarily along fault planes.

3. The Nugget Sandstone has heterogeneous reservoir properties because of (1) cyclic dune/interdune lithofacies with better porosity and permeability that developed in certain dune morphologies, (2) diagenetic effects, and (3) fracturing.

4. The Nugget Sandstone thrust belt play is divided into three subplays: (1) Absaroka thrust – Mesozoic-cored shallow structures, (2) Absaroka thrust – Mesozoic-cored deep structures, and (3) Absaroka thrust – Paleozoic-cored shallow structures. Mesozoic-cored structures subplays both represent a linear, hanging-wall, ramp anticline parallel to the leading edge of the Absaroka thrust. This ramp anticline is divided into a broad, shallow structural high (culmination) and a deep, structural low (depression). Fields in the shallow subplay produce crude oil and associated gas. Fields in the deep subplay produce retrograde condensate. The Paleozoic-cored shallow structures subplay is located immediately west of the Mesozoic-cored structures subplays. This subplay represents a very continuous and linear, hanging-wall, ramp anticline, that is also parallel

to the leading edge of the Absaroka thrust. The eastern boundary of the subplay is defined by the truncation of the Nugget against a thrust splay. Fields in this subplay produce nonassociated gas and condensate. Traps in these subplays consist of long, narrow, doubly plunging anticlines.

5. Prospective drilling targets in the Nugget Sandstone thrust belt play are delineated using high-quality 2-D and 3-D seismic data, 2-D and 3-D forward modeling/visualization tools, well control, dipmeter information, surface geologic maps, and incremental restoration of balanced cross sections to access trap geometry. Determination of the timing of structural development, petroleum migration, entrapment, and fill and spill histories is critical to successful exploration.

6. Future Nugget Sandstone exploration could focus on more structurally complex and subtle, thrust-related traps. Nugget structures may be present beneath the leading edge of the Hogsback thrust and North Flank fault of the Uinta uplift.

Jurassic Twin Creek Limestone Thrust Belt Play

1. The Jurassic Twin Creek Limestone thrust belt play in the Utah/Wyoming thrust belt province has produced over 15 million bbls (2.4 million m^3) of oil and 93 BCFG (2.6 million m^3). The Twin Creek was deposited in a shallow-water embayment south of the main body of a Middle Jurassic sea that extended from Canada to southern Utah. Like the Nugget Sandstone, traps form on discrete subsidiary closures along major ramp anticlines where the low-porosity Twin Creek is extensively fractured. The seals for the producing horizons are overlying argillaceous and clastic beds, and non-fractured units within the Twin Creek. Hydrocarbons in Twin Creek Limestone reservoirs were generated from subthrust Cretaceous source rocks.

2. Most oil and gas production is from perforated intervals in the Watton Canyon, upper Rich, and Sliderock Members of the Twin Creek Limestone. These members have little to no primary porosity in the producing horizons, but exhibit secondary porosity in the form of fractures. Identification and correlation of barriers and baffles to fluid flow, and recognizing fracture set orientations in individual Twin Creek reservoirs in the thrust belt is critical to understanding their effects on production rates, petroleum movement pathways, and horizontal well plans.

3. The Twin Creek Limestone thrust belt play is divided into two subplays: (1) Absaroka thrust - Mesozoic-cored structures and (2) Absaroka thrust - Paleozoic-cored structures. The Mesozoic-cored structures subplay represents a linear, hanging-wall, ramp anticline parallel to the leading edge of the Absaroka thrust. This ramp anticline is divided into a broad structural high (culmination) and a structural low (depression). Fields in this subplay produce crude oil and associated gas. The Paleozoic-cored structures subplay is located immediately west of the Mesozoic-cored structures subplay. This subplay represents a very continuous and linear, hanging-wall, ramp anticline, that is also parallel to the leading edge of the Absaroka thrust. The eastern boundary of the subplay is defined by the truncation of the Twin Creek against a thrust splay. Fields in this subplay

produce nonassociated gas and condensate. Traps in both subplays consist of long, narrow, doubly plunging anticlines.

4. Future Twin Creek Limestone exploration could focus on more structurally complex and subtle, thrust-related traps. Twin Creek structures may be present beneath the leading edge of the Hogsback thrust and North Flank fault of the Uinta uplift.

Jurassic Navajo Sandstone Hingeline Play

1. The only play in the central Utah thrust belt is what we call the Jurassic Navajo Sandstone Hingeline play and to date contains one discovery – Covenant field. The Navajo was deposited in the same extensive dune field, which extended from Wyoming to Arizona, as the Nugget Sandstone. Traps include anticlines associated with thrust imbricate and duplex structures, positioned near Jurassic extension faults. The principal regional seal for the Navajo producing zones consists of salt, gypsum, mudstone, and shale in the Jurassic Arapien Shale.

2. Hydrocarbons in Navajo Sandstone reservoirs were likely generated from Mississippian source rocks. The source rocks began to mature after loading or overridding by thrust plates. Additional study is needed to determine hydrocarbon paths and migration history.

3. The Navajo Sandstone at Covenant field has 424 feet (139 m) of net pay, an average of 12% porosity, up to 100 mD of permeability, an average water saturation of 38%, and a strong water drive. The OOIP for the field is estimated at 100 million bbls (15.9 million m^3); the estimated recovery factor is 40 to 50%.

4. Future exploration in the central Utah thrust belt should focus on Paleozoic-cored, blind, thrust structures east of the exposed Charleston-Nebo and Pahvant thrusts. The lack of associated gas at Covenant field suggests the possibility that gas-charged traps may be present in the play area.

Uinta Basin Plays

1. Oil and gas production in the Laramide-age Uinta Basin is mostly from the Paleocene and Eocene Green River and Colton/Wasatch Formations. In early late Paleocene time, a large lake, known as ancestral Lake Uinta, developed in the basin. Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine sediments that make up the Green River Formation. Alluvial redbed and floodplain deposits that are laterally equivalent to, and intertongue with, the Green River form the Colton/Wasatch.

2. The USGS defines two assessment units within the Green River Total Petroleum System in the Uinta Basin: the Deep Uinta Overpressured Continuous Oil Assessment Unit (Deep Uinta Basin Overpressured Continuous play in this report) and the Uinta Green River Conventional Oil and Gas Assessment Unit. The Conventional Oil and Gas Assessment Unit can be divided into plays having a dominantly southern sediment source

(Conventional Southern Uinta Basin play) and plays having a dominantly northern sediment source (Conventional Northern Uinta Basin play).

3. The Conventional Northern Uinta Basin and Deep Uinta Basin Overpressured Continuous plays cover the northern Uinta Basin. The Conventional Northern Uinta Basin play typically has drill depths ranging from 5000 feet (1500 m) to a maximum of 10,000 feet (3000 m). The play is divided into two subplays: (1) Conventional Bluebell subplay, and (2) Conventional Red Wash subplay. The Deep Uinta Basin Overpressured Continuous play is delineated where the lower 2500 to 3000 feet (750-900 m) of the Green River and intertonguing Colton Formations are overpressured (gradient >0.5 psi/ft [11.3 kPa/m]). The most rapid increase in reservoir pressure and most of the high-volume, overpressured oil production typically occurs at depths ranging from 11,000 to 14,000 feet (3400-4300 m).

4. In the Conventional Bluebell subplay, sandstone reservoirs typically have low porosity (8 to 12%) and low matrix permeability (0.01 to 10 mD). Sandstone reservoirs in the Conventional Red Wash subplay have higher porosities (8 to 20%) and significantly higher matrix permeabilities, commonly 50 to 500 mD. In the Deep Uinta Basin Overpressured Continuous play, production is fracture controlled in reservoir rocks, which typically have very low (< 0.1 mD) matrix permeability. The reservoirs are fractured lenticular sandstone, shale, and marlstone deposited in the lacustrine and alluvial environments of Lake Uinta.

5. Fields in the Conventional Northern Uinta Basin play and Deep Uinta Basin Overpressured Continuous play produce crude oil with associated gas. Production from the Conventional Bluebell subplay cannot be accurately separated from the Deep Uinta Basin Overpressured Continuous play. The largest fields in the Conventional Red Wash subplay have produced 155.9 million BO (24.8 million m^3) and 474.6 BCFG (13.4 BCMG). The Deep Uinta Basin Overpressured Continuous play has produced nearly 300 million BO (50 million m^3) and 500 BCFG (14 BCM) primarily from three large fields – Altamont, Bluebell, and Cedar Rim.

6. The Conventional Northern Uinta Basin play and Deep Uinta Basin Overpressured Continuous play areas are also being explored for Mesaverde Group and Mancos Shale gas. The deeper drilling for gas could result in the discovery of new oil fields in the overlying Green River Formation.

7. The Conventional Southern Uinta Basin play is divided into six subplays: (a) Conventional Uteland Butte interval, (b) Conventional Castle Peak interval, (c) Conventional Travis interval, (d) Conventional Monument Butte interval, (e) Conventional Beluga interval, and (f) Conventional Duchesne interval fractured shale/marlstone.

8. The source rocks for the crude oil produced from the Uinta Basin plays are also found in the Green River Formation and consist of kerogen-rich shale and marlstone, which were deposited in nearshore and offshore open-lacustrine environments. Most of these oils are

characterized as yellow or black wax. Production from the Deep Uinta Basin Overpressured Continuous play is dominantly yellow wax, while most of the oil production from the Conventional Northern Uinta Basin play and Conventional Southern Uinta Basin play is black wax.

9. Future exploration in the Green River Formation of the Uinta Basin should consist of extending the productive limits of existing fields by step-out drilling and wildcat drilling along producing trends.

Mississippian Leadville Limestone Paradox Basin Play

1. The Mississippian Leadville Limestone is a major oil and gas play in the Paradox Basin, having produced over 53 million barrels (8.4 million m^3) of oil and 845 billion cubic feet (BCF [23.9 billion m^3]) of gas. Most Leadville production is from the Paradox fold and fault belt. The Leadville is a shallow, open marine, carbonate-shelf deposit. Local depositional environments included shallow-marine, subtidal, supratidal, and intertidal. Solution breccia and karstified surfaces are common. Most oil and gas produced from the Leadville is found in basement-involved structural traps with closure on both anticlines and faults. Lisbon, Big Indian, Little Valley, and Lisbon Southeast fields are found on sharply folded anticlines that close against the Lisbon fault zone. Salt Wash and Big Flat fields, northwest of the Lisbon area, are found on unfaulted, east-west- and north-south-trending anticlines, respectively. The unfaulted structures probably developed from movement on deep, basement-involved faults that do not rise to the level of the Leadville. These and other faults affecting the Leadville probably reflect the reactivation of preexisting, Precambrian-age faults during the Laramide orogeny or later.

2. Hydrocarbons in Leadville Limestone reservoirs were likely generated from source rocks in the Pennsylvanian Paradox Formation. Hydrocarbon generation occurred during maximum burial in the Late Cretaceous and early Tertiary. The seals for the Leadville producing zones are the overlying clastic beds of the Pennsylvanian Molas Formation and evaporite (salt and anhydrite) beds within the Pennsylvanian Paradox Formation.

3. The Leadville Limestone has heterogeneous reservoir properties because of depositional facies with varying porosity and permeability, diagenetic effects, and fracturing. The early diagenetic history of the Leadville sediments, including some dolomitization (finely crystalline) and leaching of skeletal grains, resulted in low-porosity and/or low-permeablility rocks. Most of the porosity and permeability associated with hydrocarbon production at Lisbon field was developed during later, deep subsurface dolomitization (coarsely crystalline replacement and saddle [hydrothermal?] dolomite) and dissolution.

4. In major reservoirs, the produced Leadville oil and condensate are rich, volatile crudes. Leadville reservoirs produce associated gas that is variable in composition; nonassociated gas is relatively uniform in composition.

5. New prospective drilling targets in the Leadville Limestone Paradox Basin play are delineated using high-quality 2-D and 3-D seismic data, 2-D and 3-D forward

modeling/visualization tools, well control, dipmeter information, and surface geologic maps to assess trap geometry. Relatively low-cost surface geochemical surveys, hydrodynamic analysis, and epifluorescence techniques may identify potential Leadville hydrocarbon migration patterns and oil-prone areas.

Pennsylvanian Paradox Formation Paradox Basin Play

1. The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play. The Paradox Formation has produced over 500 million bbls (80 million m^3) of sweet, paraffinic oil and 650 BCFG (18 billion m^3) from more than 70 fields. The main producing zones are referred to as the Desert Creek and Ismay. The Paradox Formation oil play area includes nearly the entire Paradox Basin. The Paradox Formation Play is divided into four subplays: (1) fractured shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone.

2. In Pennsylvanian time, the Paradox Basin was rapidly subsiding in a subtropical arid environment with a shallow-water carbonate shelf on the south and southwest margins of the basin that locally contained carbonate buildups. In the Blanding sub-basin, Ismay-zone reservoirs are dominantly limestones composed of small, phylloid-algal buildups; locally variable, inner-shelf, skeletal calcarenites; and rarely, open-marine, bryozoan mounds. Desert Creek-zone reservoirs are dominantly dolomite comprising regional, nearshore, shoreline trends with highly aligned, linear facies tracts. On the Aneth platform, Desert Creek reservoirs include shallow-shelf buildups (phylloid algal, coralline algal, and bryozoan buildups [mounds]) and calcarenites (beach, dune, and oolite banks). Here, the Desert Creek and Ismay zones are predominately limestone, with local dolomitic units.

3. Phylloid-algal mound lithofacies in both the Ismay and Desert Creek zones contain large phylloid-algal plates of *Ivanovia*, *Kansasphyllum*, or *Eugonophyllum*, and skeletal grains create bafflestone or bindstone fabrics. Bryozoan buildup lithofacies are represented by bindstone, bafflestone, and packstone fabrics that are rarely dolomitized. Calcarenite lithofacies include grainstone and packstone fabrics containing oolites, coated grains, hard peloids, bioclastic grains, shell lags, and intraclasts.

4. Hydrocarbons in Paradox Formation reservoirs were generated from source rocks within the formation itself during maximum burial in the Late Cretaceous and early Tertiary. Organic-rich units, informally named the Cane Creek, Hovenweep, Chimney Rock, and Gothic shales, are composed of black, sapropelic shale and shaley dolomite. Vertical reservoir seals for the Paradox producing zones are shale, halite, and anhydrite within the formation; lateral seals are permeability barriers created by unfractured, off-mound (non-buildup) mudstone, wackestone, and anhydrite.

5. Trap types in the Blanding sub-basin and Aneth platform regions include stratigraphic, stratigraphic with some structural influence, combination stratigraphic/structural, and diagenetic. Many carbonate buildups appear to have developed on subtle anticlinal noses or structural closures.

6. The Paradox Formation has heterogeneous reservoir properties because of depositional lithofacies with varying porosity and permeability, carbonate buildup (mound) relief and flooding surfaces (parasequence boundaries), and diagenetic effects. The extent of these factors, and how they are combined, affect the degree to which they create barriers to fluid flow. Identification and correlation of depositional lithofacies and parasequences in individual Paradox reservoirs is critical to understanding their effect on water/carbon dioxide injection programs, production rates, and paths of petroleum movement. The typical early diagenetic events occurred in the following order: (1) early marine cementation, (2) post-burial, replacement, rhombic dolomite cementation due to seepage reflux, (3) vadose and meteoric phreatic diagenesis including leaching/dissolution, neomorphism, and fresh-water cementation, (4) mixing zone dolomitization, (5) syntaxial cementation, and (6) anhydrite cementation/replacement. Post-burial diagenesis included additional syntaxial cementation, silicification, late coarse calcite spar formation, saddle dolomite cementation, stylolitization, additional anhydrite replacement, late dissolution (microporosity development), and bitumen plugging.

7. Mapping the Ismay-zone lithofacies delineates very prospective reservoir trends that contain productive carbonate buildups around anhydrite-filled intra-shelf basins. Lithofacies and reservoir controls imposed by the anhydritic intra-shelf basins should be considered when selecting the optimal location and orientation of any horizontal drilling for undrained reserves. Projections of the inner shelf/tidal flat and mound trends around the intra-shelf basins identify potential exploration targets. Pervasive marine cement may be indicative of "wall" complexes of shallow-shelf carbonate buildups suggesting potential nearby carbonate buildups, particularly phylloid-algal mounds. Platform-margin calcarenites in the Desert Creek zone are located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. Mapping indicates a relatively untested lithofacies belt of calcarenite carbonate deposits south and southeast of Greater Aneth field.

8. Fractured-shale beds in the Pennsylvanian Paradox Formation are oil productive in the Paradox Basin fold and fault belt of southwest Utah. Jointing and fractures are controlled by regional tectonics and more localized salt movement, dissolution, and collapse. In the fold and fault belt, the Cane Creek shale of the Paradox Formation is composed of marine carbonates, evaporites, and organic-rich shale. The Cane Creek is a fractured, self-sourced oil reservoir that is highly overpressured – an ideal target for horizontal drilling. Fracture data from oriented cores in the Cane Creek show a regional, northeast to southwest, near-vertical, open, extensional fracture system that is not significantly affected by orientations of localized folds.

Outcrop Analogs for Major Reservoirs

Utah is unique in that representative outcrop analogs for each major oil play are present in or near the thrust belt, Uinta Basin, and Paradox Basin. Production-scale analogs provide an excellent view, often in 3D, of reservoir-facies characteristics (geometry, distribution, and so forth) and the nature of boundaries contributing to the overall heterogeneity of reservoir rocks.

Outcrop analogs can be used as a "template" for evaluation of data from conventional core, geophysical and petrophysical logs, and seismic surveys. When combined with subsurface geological and production data, analog models improve development drilling and production strategies, reservoir-simulation models, reserve calculations, and design and implementation of secondary/tertiary oil recovery programs and other best practices used in the oil fields of Utah and vicinity.

Thrust Belt

Jurassic Nugget and Navajo Sandstone: The most prolific oil reservoir in the thrust belt is the Jurassic Nugget Sandstone, which was deposited in an extensive dune field that extended from Wyoming to Arizona. The best outcrop analogs to the Nugget Sandstone reservoir are found in exposures of the stratigraphically equivalent Navajo Sandstone of southern Utah. Outcrops along the shores of Lake Powell and in the San Rafael Swell display classic eolian bedforms such as large-scale dunal cross-strata, and interdunal features such as oases, wadi, and playa lithofacies. Navajo interdune lithofacies have significantly poorer reservoir characteristics than the dune lithofacies and in a reservoir represent potential barriers to flow. Identification and correlation of dune/interdune lithofacies in individual Nugget reservoirs in the thrust belt is critical to understanding their effects on production rates and paths of petroleum movement.

Jurassic Twin Creek Limestone: The best outcrop analogs for the Twin Creek Limestone reservoir are found west of Anschutz Ranch field at Devils Slide on the Crawford thrust plate and southwest of Lodgepole field near the town of Peoa, Utah, on the Absaroka thrust plate (?). Closely spaced rhombic and rectilinear fracture patterns developed on bedding planes and within dense, homogeneous non-porous (in terms of primary porosity) limestone beds of the Rich and Watton Canyon Members. The contact with the basal siltstone units (where fractures are sealed) of the overlying members set up the Rich and Watton Canyon for hydrocarbon trapping and production. Thin-bedded siltstone within the Rich and Watton Canyon Members, also observed in outcrop, creates additional reservoir heterogeneity. Identification and correlation of these barriers and baffles to fluid flow, and recognizing fracture set orientations in individual Twin Creek reservoirs in the thrust belt is critical to understanding their effects on production rates, petroleum movement pathways, and horizontal well plans.

Uinta Basin

Deep Uinta Basin Overpressured Continuous play: Outcrop analogs for the Deep Uinta Basin Overpressured Continuous play in Sevier and Sanpete Counties, central Utah, provide examples of deposits shed off the western highlands into Lake Uinta. Many of the proximal conglomerates were deposited in water by fan deltas extending into the lake. Other exposures of medial facies include interbedded shale, sandstone, and limestone deposited in a marginal-lacustrine environment. The distal facies of the Flagstaff Limestone is composed of open-lacustrine shale and limestone.

Conventional Northern Uinta Basin play: An outcrop analog for the major oil reservoirs in the Conventional Northern Uinta Basin play is exposed along Raven Ridge in the northeastern Uinta Basin; these exposures display landward to lakeward facies transitions in the Green River

Formation. Several locations offer excellent exposures of shoreline deposits that serve as reservoirs, and bay-fill deposits that provide organic-rich source rock for the play.

Conventional Southern Uinta Basin play: Outcrop analogs for the major oil reservoirs in the Green River Formation in the Conventional Southern Uinta Basin play are well exposed in Willow Creek, Indian, and Nine Mile Canyons in the south-central Uinta Basin. The Uteland Butte interval is exposed in Nine Mile Canyon as dolomitized ostracod and pellet grainstone and packstone deposited in shallow-water mudflats; pelecypod-gastropod sandy grainstone, commonly interbedded with silty claystone or carbonate mudstone deposited in shallow open-lacustrine environments; and dark-gray kerogen-rich carbonates deposited in deeper offshore environments. The Castle Peak interval is exposed in the western portion of Nine Mile Canyon as interbedded carbonate, shale, and sandstone. The primary reservoir rocks are isolated channel deposits. The secondary reservoirs in the Travis interval and the primary reservoirs in the Monument Butte and Beluga intervals are distributary-channel deposits. The Monument Butte interval typically contains amalgamated stacked channel deposits, whereas in the Travis and Beluga intervals, the distributary channels are generally isolated individual channels. One location in Nine Mile Canyon, termed the Nutter's Ranch study site, is an outcrop analog for the Travis (secondary reservoir), Monument Butte, and Beluga intervals. Examination of the outcrop identified the potential heterogeneity that can exist between wells in two dimensions (as well as over a square mile), as an analogy to a typical waterflood unit in the Monument Butte field area to the north. The Duchesne interval represents the maximum rise and eventual waning stages of ancient Lake Uinta and is well exposed in Indian Canyon south of the town of Duchesne.

Fractures can be observed in the Green River Formation in Indian Canyon and throughout the surface exposures in the Duchesne field along the Duchesne fault zone. Any fractured outcrop in the upper and saline members can be considered a reservoir analog.

Paradox Basin

Mississippian Leadville Limestone: Excellent outcrops of Leadville-equivalent rocks are found in the Madison Limestone along the south flank of the Uinta Mountains, Utah, and in the Redwall Limestone in the Marble Canyon area of Grand Canyon National Park, Arizona. They provide production-scale analogs of facies characteristics, geometry, distribution, and the nature of boundaries contributing to the overall heterogeneity of Leadville reservoir rocks. The Madison and Redwall are fine- to coarse-crystalline, cherty limestone with some dolomite. Limestone units commonly contain numerous caverns, sinkholes, and local zones of solution breccia and vugs. Sections can have high heterogeneity due to stylolites, jointing, and fractures. Possible buildups, shoals or banks, and mud mounds comparable to Waulsortian facies are also found in these formations.

Pennsylvanian Paradox Formation: In the Paradox Basin, hydrocarbons are stratigraphically trapped in heterogeneous reservoirs within carbonate buildups (or phylloid-algal mounds) of the Pennsylvanian Paradox Formation. Carbonate buildups exposed in the Paradox Formation at Eight-Foot Rapid, Honaker Trail, and The Goosenecks along the San Juan River of southeastern Utah provide excellent outcrop analogs of these reservoir rocks. Reservoir-quality porosity may develop in the types of lithofacies associated with buildups, such as troughs, detrital wedges, and

fans, identified from these outcrops. If these lithofacies are in communication with mound-reservoir lithofacies in actual reservoirs, they could serve as conduits facilitating sweep efficiency in secondary/tertiary recovery projects. However, the relatively small size and the abundance of intermound troughs over short distances, as observed along the river, suggests caution should be used when correlating these lithofacies between development wells. Lithofacies that appear correlative and connected from one well to another may actually be separated by low-permeability lithofacies which inhibit flow and decrease production potential. These outcrop analogs also demonstrate that there are various targets and risks when considering potential horizontal drilling in the Paradox Basin. Before selecting the optimal location, orientation, and type of horizontal well, the distribution both laterally and vertically of phylloid-algal mounds and other associated lithofacies must be carefully evaluated.

Land Classification

1. The four oil-producing provinces in this study (Utah/Wyoming thrust belt, Central Utah thrust belt – Hingeline, Uinta Basin, and Paradox Basin) encompass nearly 15.1 million acres (6.1 million ha) and include almost all of the potential oil- and gas-bearing land in Utah and adjacent lands in parts of Arizona, Colorado, and Wyoming. Surface and mineral ownership is divided primarily among federal, state, private, and Native American interests. Nearly 8.6 million acres or 57% of the land is federally owned and administered by the BLM and several other federal agencies including the USFS, NPS, U.S. Fish and Wildlife Service, U.S. DOD, and U.S. BOR. BLM and other federally administered public lands, constitute the largest ownership entity in the four oil-producing provinces with 42.6% of the total acreage. Other major land designations include state lands, private or fee lands, and Native American Reservation lands.

2. State lands, including state parks and wildlife reserves, comprise 8.2% of the total land in the four provinces and include 1.25 million acres (510,000 ha). Each state has its own agency or agencies that administer its respective lands, and commissions or divisions that administer oil and gas development. There are no state-owned lands in the Arizona part of the Paradox Basin province. For Colorado, state agencies include the Colorado State Land Board and the COGCC. In Utah, state lands are administered by either the Utah Division of Forestry, Fire, and State Lands or by SITLA. Oil and gas development in Utah is administered by the UDOGM. In Wyoming, state lands are administered by the Wyoming Office of State Lands and oil and gas development is administered by the WYOGCC. Web site and contact information for all of these entities is contained in the body of this report and in the appendices.

3. Privately owned lands or fee lands comprise 23.1% of the oil provinces and encompass nearly 3.5 million acres (1.4 million ha). These lands are owned by individuals, corporate or legal entities, or a sovereignty in the case of an Indian tribe. In each case, oil and gas rights or leases are negotiated with the mineral-estate owner(s) and surface access, if required, is negotiated with the surface owner. Where an Indian tribe owns the mineral estate, leases are usually negotiated with the tribal business committee. Numerous royalty owners associations have been formed to pool information and lease

management among groups of individual royalty owners. The most prominent of these non-profit organizations is the National Association of Royalty Owners.

4. Native American Reservation lands comprise 11.5% of the oil provinces and include 1.7 million acres (690,000 ha) of land within an established Indian Reservation. These lands are held in trust by the U.S. government and administered by the Bureau of Indian Affairs (BIA). Also, within some reservations, tribal members own land individually; these are referred to as allotted lands. Because of the complexity of Indian land ownership, only designated reservation lands are shown on the maps. Native American Reservation lands in the Uinta Basin province are within the Uinta & Ouray Indian Reservation, which is headquartered in Fort Duchesne, Utah. Native American Reservation lands in the Paradox Basin province are Navajo Nation lands whose offices are in Window Rock, Arizona, and Ute Mountain Indian Reservation lands whose tribal offices are in Towaoc, Colorado. Native American Reservation lands in the Central Utah thrust belt-Hingeline province are Paiute Indian Reservation lands whose tribal office is in the town of Joseph, Utah.

5. In an attempt to make the administrative effort more responsive to individual tribal interests, the BIA has developed a set of rules regarding Tribal Energy Resource Agreements, which offer federally recognized tribes a new alternative for overseeing and managing energy and mineral resource development on their lands. All of the rules and regulations pertaining to oil and gas development on BIA-administered tribal lands are posted on the BIA Web site.

6. Mineral ownership patterns vary among the oil provinces, and dominant ownership is somewhat different in each area although federal ownership is dominant overall. Federal ownership is multifaceted in that while the mineral estate is managed primarily by the BLM, the overlying surface estate might be managed by other federal agencies. The surface estate may also be privately owned, creating a split estate, which is common in the Western U.S. The BLM, in consultation with numerous oil and gas, ranching, and other organizations, has established a set of guidelines for dealing with split mineral estate issues.

7. All federal agencies are governed by laws, which provide mandatory direction to agencies; regulations, which are promulgated by each agency and are subject to public review; and policies, which further complement the laws and regulations. Policies are internal documents that have no external review requirement.

8. Two key laws influence BLM's planning efforts: the FLPMA of 1976, and the NEPA of 1969. The BLM National Planning Handbook outlines a process that meets the requirements of both NEPA and FLPMA for the development of planning decisions. An interdisciplinary team established to work on planning projects ensures that the BLM is complying with other laws, regulations, and policies associated with particular resources and uses of the public lands. Together, NEPA and FLPMA, as well as the associated regulations, form the basis for BLM's planning process. The BLM's planning handbook

is a BLM policy that encompasses the requirements of NEPA and FLPMA laws and regulations.

9. BLM lands are managed on a national level by federal regulations, on a state level by the statewide administration of federal regulations and state policies, and on a local level by field offices, which are responsible for the day-to-day management and resource planning for federal lands within their areas of responsibility. Public lands are available for oil and gas leasing only after they have been evaluated through the BLM's multiple-use planning process.

10. The BLM issues two types of leases for oil and gas exploration and development on lands owned or controlled by the federal government - competitive and noncompetitive.

11. The Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and not received a bid.

12. The maximum competitive lease size is 2,560 acres (1036 ha) in the lower 48 states and 5,760 (2331 ha) acres in Alaska. The maximum noncompetitive lease size in all states is 10,240 acres (4144 ha).

13. Since passage of the Energy Policy Act of 1992, both competitive and noncompetitive leases are issued for a 10-year period. Both types of leases continue for as long thereafter as oil or gas is produced in paying quantities.

14. Oral auctions of all oil and gas leases are conducted by most BLM state offices not less than quarterly when parcels are available. A Notice of Competitive Lease Sale, which lists lease parcels to be offered at the auction, will be published by each BLM state office at least 45 days before the auction is held. Lease stipulations applicable to each parcel are specified in the Sale Notice. Lands included in the sale are identified by informal expressions of interest from the public, or by the BLM for management reasons, or lands included in offers filed for noncompetitive leases. All auctions are conducted with oral bidding. Bidders must attend the auction to obtain a competitive lease or provide for someone to represent them.

15. In general, leases are granted on the condition that the lessee will have to obtain BLM approval before conducting any surface-disturbing activities. Oil and gas leasing sale notices and sale results are posted on each BLM state office's Web site as well as other oil and gas related federal agency Web sites.

16. Following issuance of a lease and before exploratory drilling can begin, the leaseholder must submit an Application for Permit to Drill (APD). This application process is very rigorous and comprehensive. The application of Best Management Practices in oil and gas leasing is defined in the new *Gold Book,* a joint effort of the BLM and FS.

17. Oil and gas lease maps and surface and mineral land status maps can be created through the BLM's National Integrated Land System (NILS) <http://www.blm.gov/nils/>. NILS is a joint project between the BLM and the FS in partnership with the states, counties, and private industry to provide business solutions for the management of cadastral records and land parcel information in a GIS environment.

18. Land use planning emphasizes a collaborative environment in which local, state, and tribal governments, the public, user groups, and industry work with the BLM to identify appropriate multiple uses of the public lands. The land-use planning process allows for extensive public involvement and provides a blueprint of how the public land should be managed.

19. Documentation for each Land Use Plan (LUP) and Resource Management Plan (RMP) is available on each BLM state office Web site and local field office Web sites.

20. Several BLM districts in Utah, Colorado, and Wyoming are in the process of creating new RMPs. Some of Utah's RMPs that are under revision have been identified by the BLM as 'Time Sensitive Resource Management Plans' to timely address energy resources studied under the Energy Policy and Conservation Act (EPCA). In Utah, these include the Price and Vernal RMPs, which are in the Paradox Basin and Uinta Basin oil provinces, respectively. Under EPCA, signed into law by President Clinton in 2000, federal agencies were tasked with developing a national inventory of all oil and gas resources and reserves beneath federal lands. This data is now being incorporated into RMPs to plan for multiple uses on the public lands, and specifically plan for the responsible development of energy resources in these areas. Other new resource planning efforts for the major oil provinces include: Utah/Wyoming thrust belt — Kemmerer RMP, Central Utah thrust belt—Hingeline — Richfield RMP, Uinta Basin — White River RMP, Paradox Basin — Moab RMP, Monticello RMP, and Richfield RMP.

21. In addition to BLM public lands, federal lands designated as Wilderness Areas by Congress are specifically withdrawn from any type of development. Only one Wilderness Area is located within the four oil provinces. However, numerous WSA and ISA lands in the Uinta Basin and Paradox Basin provinces, totaling 1,044,468 acres (422,690 ha), have been identified and mapped in each of the oil provinces. These lands are managed by the BLM under special interim rules until they are either designated as Wilderness or released. A history of the debate over Wilderness and links to documentation for each WSA and ISA is provided in the Land Classification Summary chapter (Ch-12) of this report.

Best Practices

Jurassic Nugget/Navajo Sandstone and Twin Creek Limestone Thrust Belt Plays

1. Horizontal drilling in Utah/Wyoming thrust belt fields targets the heterogeneous Nugget Sandstone and Twin Creek Limestone reservoirs. Drilling techniques include new wells

and horizontal, often multiple, laterals from existing vertical wells. Multiple laterals are recommended where two separate, geologically distinct zones are present. To avoid problems in the Preuss salt it is recommended that drilling penetrate 500 feet (150 m) into non-productive upper Twin Creek before turning horizontal. Fractures and lithologic variations create potential undrained compartments ideally suited for horizontal drilling. Horizontal wells should generally be drilled perpendicular to the dominant orientation of open fractures, and above and parallel to the low-proved oil or oil/water contacts. The smallest area that can be effectively drained with a 2000-foot (600-m) horizontal well in fractured Twin Creek reservoirs is 640 acres (260 ha).

2. The horizontal drilling programs at Pineview, Lodgepole, and Elkhorn Ridge, Painter Reservoir, and Ryckman Creek fields in the thrust belt, successfully extended the productive life of the fields. Horizontal drilling was probably uneconomical at Pineview, marginally economic at Lodgepole, and economically successful at Elkhorn Ridge. All three fields were at an advanced stage of depletion when the horizontal drilling began, and in structurally complex settings making it difficult to avoid production of formation water.

3. Horizontal drilling technology was not readily available when the Pineview, Lodgepole, and Elkhorn Ridge fields, Utah, were discovered and developed. Horizontal drilling, particularly the success at Elkhorn Ridge field, does demonstrate that the fractured Watton Canyon Member of the Twin Creek Limestone is an excellent reservoir for horizontal drilling in other discoveries. If horizontal technology had been available these fields could have been developed with fewer wells (smaller footprint), and would have resulted in a greater ultimate oil recovery.

4. The enhanced oil recovery waterflood project in the Elkhorn Ridge field utilizes horizontal wells. The project is just beginning and it is too early to determine its effectiveness. The fractured nature of the Watton Canyon Member of the Twin Creek Limestone could result in early breakthrough of injected water. But, the alternative would have been abandonment of the field. The waterflood project will provide valuable information about the enhanced recovery potential of the Watton Canyon reservoir and similar fractured reservoirs.

5. Horizontal drilling programs were conducted in both Painter Reservoir and Ryckman Creek fields, Wyoming, to: (1) improve areal connectivity of the wellbores and productive strata, (2) improve drainage geometry, (3) reduce coning and cusping, (4) reduce the tendency to produce sand along with hydrocarbons, (5) increase sweep efficiency of the nitrogen and waterfloods, and (6) reduce field development costs thus allowing increased oil recovery. Applying this technology to injection wells also helped pressure maintenance performance.

6. Reservoir compositional simulation studies were conducted on Painter Reservoir field. Ultimate recovery was determined for a tertiary, miscible nitrogen-injection program. In this process, nitrogen and hydrocarbon gas are over-injected into the reservoir to raise the reservoir pressure to miscible conditions producing an excellent sweep of oil over a 60-

year period. The simulation indicated that when this program is supplemented with water injection, the ultimate recovery would be 113 million bbls (18 million m^3) of oil (a 68% recovery factor).

7. Retrograde gas condenses from a single phase when the dew-point pressure is reached, and upon further pressure reduction, forms a liquid phase in the reservoir. As the reservoir pressure is depleted further, additional condensation will take place until a pressure is reached at which the liquid begins to vaporize. Thus, there is a maximum in the volume of liquid that condenses. Further pressure reduction will not revaporize all of the liquid, and some will be left as an immobile liquid phase in the reservoir at the time of abandonment. Reservoir management of retrograde condensate reservoirs is both critical, to maximize recovery and value from this type of reservoir, and challenging, because of the need to evaluate the phase behavior of retrograde condensate reservoir fluids under alternative depletion plans. To maximize liquid recovery, a thorough understanding of reservoir geometry, fluid distribution, and phase behavior must be included as part of the overall technical evaluation (from Welch, 1993).

8. Anschutz Ranch East field on the Utah/Wyoming border is a prime example of a rich condensate gas reservoir. Soon after the field was discovered in 1979, the operators realized that it would require unitization to assure maximum liquid recovery through efficient reservoir management. Even prior to initiating full field production, the reservoir was evaluated to determine a plan of depletion. The evaluation of Anschutz Ranch East led to a full reservoir pressure maintenance project that required initial injection of a buffer gas equal in volume to 10% of the hydrocarbon pore volume. The buffer gas was a mixture of 35% nitrogen and 65% wet gas followed by the injection of pure nitrogen (from Welch, 1993). Cumulative production from Anschutz Ranch East field is over 129 million bbls (20.5 million m^3) of condensate.

9. Development wells drilled to the Jurassic Navajo Sandstone in Covenant field, central Utah thrust belt – Hingeline, are perforated in selected intervals with four jet shots per foot. The perforations are broken down using small, 7.5% hydrochloric acid treatments with additives, primarily to clean perforations of clays from drilling muds. Electrical submersible pumps are installed to artificially lift fluids. The well spacing is about 40 acres (16 ha) within the Covenant unit. Wells are drilled from three pads and deviated to avoid rugged topography. Secondary and tertiary recovery programs may include nitrogen injection and/or a carbon dioxide flood.

Uinta Basin Plays

Deep Uinta Basin Overpressured Continuous and Conventional Northern Uinta Basin plays:

1. Reservoir analysis indicates that there is a significant amount of oil left to be produced in Altamont-Bluebell-Cedar Rim wells in the Deep Uinta Basin Overpressured Continuous and Conventional Northern Uinta Basin plays. Accurately identifying which beds actually contribute to the production and the role that naturally occurring fractures play in

the reservoir remains a major problem for maximizing petroleum production. We recommend that operators in the Bluebell field use geophysical and imaging logs as the primary tools for selecting perforations in new wells, not drilling shows as is commonly done. This should result in a reduction of the number of beds perforated, and more effective treatment.

2. A large resource potential in the Deep Uinta Basin Overpressured Continuous and Conventional Northern Uinta Basin plays may be in recompletions of the current wells. Well completions have typically consisted of perforating 40 or more beds in a 1500-foot (450 m) or more, vertical section. As a result, many of the beds never received adequate stimulation. We recommend using cased-hole logs to identify by-passed oil and selectively stimulating individual beds to recover significant amounts of additional oil. In recompletion of existing wells, cased-hole logs can help identify additional beds to be perforated, and if necessary, identify beds that can be treated individually.

3. The treatment methods used by operators in the Altamont-Bluebell-Cedar Rim field trend have not changed significantly over the years (until recently), except for treating larger intervals and more perforations. Almost all the completions follow the same general procedures, varying only slightly in the volume of acid and the types of additives used. As a result, no treatment method appears better than another, because there is such little difference between them. As treatment intervals get larger, it is apparent that many of the beds are not getting treated because of the difficulty of diverting the acid into so many different beds. Staging acid treatments over smaller (500-foot [150 m]) intervals and greatly increasing the amount of diversion material used has been shown by operators in Bluebell field to be effective treatment techniques. Particularly in newer wells, perforating fewer beds and treating shorter gross intervals can result in more effective completions. In recompleting wells, staging the treatments over shorter intervals and more effective diversion of the treatment fluid to the desired interval, will result in better completions. Typically, an operator treating a 1500-foot (500-m) interval will treat the lower 500 feet (160 m), move the packer up and treat the middle 500 feet (152 m), and then treat the upper 500-foot (160-m) interval. Ideally, the diversion material plugs the perforations of a stage before moving up hole so only 500-foot (160-m) sections are being treated at a time.

4. Older wells that have been recompleted many times eventually become uneconomical to retreat. In these wells only a minor incremental increase in the oil production rate occurs after treatment because so much of the acid is going into beds that are depleted of oil. A bed-scale completion technique could be effective in older wells nearing depletion where a larger staged completion is no longer economical. Therefore, in older wells it is recommended that treatment of a few individual beds be attempted using a dual packer tool. This way, only the few beds with remaining oil potential are acidized, reducing the size of the treatment needed, and providing more effective stimulation of the beds with remaining potential.

5. Regardless of what type of stimulation is tried, who tries it, or what it costs, better bed evaluation is critical to increasing production from the Altamont-Bluebell-Cedar Rim

field trend. The interval to be treated could be reduced by (1) isolation with a bridge plug and packer, (2) use of a Pin Point Injection packer (PPI tool), or (3) use of a packer and the natural pressure gradient, which is present within the formation. Large perforated intervals are extremely difficult to treat down 2-7/8-inch-diameter (7-cm) tubing. Good diversion is critical to treating the entire interval and a high enough pumping rate must be maintained to effectively carry the diverting agent.

6. HCl has been the recommended treating fluid. The following list of additives would be advisable to be run per 1000 gallons (3800 L) of 15% HCl:

    - 5 to 10 gallons (19-38 L) corrosion inhibitor (temperature dependent),
    - 3 to 10 gallons (11-38 L) surfactant (concentration will vary depending on compatibility of surfactant with the produced oil),
    - 3 to 7 gallons (11-26 L) clay control (concentration will vary depending type of clay control additive that is used),
    - 10 gallons (38 L) iron control (minimum),
    - 10 gallons (38 L) acid gelling agent,
    - 10 gallons (38 L) solvent (minimum), and
    - 10 gallons (38 L) scale inhibitor.

7. In addition to the additives, the tubing should be pickled and reversed out just prior to doing the main acid treatment. This may involve more cost, but will minimize formation damage from iron dissolved from the tubulars. A rule of thumb for pickling tubulars is to use 100 gallons (375 L) of HCl for every 1000 feet (300 m) of tubing. The treating fluid should be recovered as quickly as possible, not allowing it to sit in the formation; this will help prevent fines and other solids from dropping out in the formation. The initial acid treatment is generally the largest and appears to be the most effective. If additional acid treatments are pumped, it is advisable to pump volumes similar to, or smaller than, the initial acid treatment. The most cost-effective acid treatment appears to be between 20,000 and 30,000 gallons (75,700 and 113,600 L) of 15% HCl pumped in four acid stages. This would mean pumping three diverter stages with enough volume to divert the fluid from one zone to another. The diverter fluid should be gelled so that the friction characteristics are similar to that of the acid. The diverter fluid should also be compatible with the diverter material, and contain the same surfactants and clay control additives that are used in the acid system. If ball sealers are used, a minimum of 50% excess will give proper diversion if the fluid volume and pumping rate are appropriate, and the perforations are in good shape.

8. Operators generally believed that past performance shows that proppant fracture treatments don't work in the Altamont-Bluebell-Cedar Rim field trend. However, with over 300 wells drilled in the Bluebell field alone, only 2% of the treatments were proppant fracture treatments, indicating that hydraulic fracturing with proppant has not been adequately tested, mainly because of the cost. Beginning in the early 2000s most operators have begun using only proppant fracture stimulations. Treatments that were hydraulically fractured with a proppant used only a small volume of sand as the propping agent. The ability to do high-rate proppant fracs over large intervals has been proven in

other fields in the Uinta Basin and should be possible in the Altamont-Bluebell-Cedar Rim field trend. Many older wells may not be suitable for this treatment, but newer wells should be considered as likely candidates for high-rate, proppant-fracture treatments.

9. Variations in six parameters affect the precipitation of $CaCO_3$ scale from produced oil-well waters in the Altamont-Bluebell-Cedar Rim field trend: (1) basic water chemistry, (2) pH, (3) CO_2 content, (4) pressure changes, (5) salinity changes, and (6) temperature changes. Waters with high percentages of both calcium and bicarbonate favor greater precipitation. Low-pH (more acidic) waters precipitate less $CaCO_3$ than high-pH (more basic) waters. High CO_2 content favors less precipitation than low CO_2 content. Decreases in pressure and/or increased turbulence favor the precipitation of $CaCO_3$. Reductions in salinity favor less precipitation. Increased temperatures, both initial and equilibrium, favor increased $CaCO_3$ precipitation. The co-production of Green River and Wasatch Formation waters increases the amount of $CaCO_3$ scale that is produced over that which is produced from Wasatch water alone.

10. There is no clear correlation between hydrocarbon production and type and size of treatment. However, the acid treatments are apparently understimulating the wells, as shown by the limited amount of time the wells are in linear flow. Surprisingly, no correlation occurs between the amount of acid pumped and the size of the interval being treated. Moderate-sized acid treatments are about as economical as large acid treatments regardless of the interval being treated. Most wells in the area have been treated more than once. Typically the first and second treatments yield the best results, whereas the third and fourth treatments do not appear to be as effective, but these later treatments were also typically smaller. The first and second treatments appear to be fairly effective in increasing production for up to four to five months. Later treatments are probably less effective because they are applied to older wells that are partially depleted. The volume of the treatment does not appear to be a major factor. Treatments that range from 20,000 to 30,000 gallons (75,700-113,600 L) seem to be slightly more effective, but apparently the most critical acid treatment is the first one. If additional acid treatments are to be pumped, they should be about the same size as the first treatment, not smaller as is often the case.

11. Higher pumping rates and well-head-treating pressure result in more effective treatments. The higher pressures and pumping rates could be indications of good diversion taking place, which allows more of the treatment fluids to enter more of the formation. However, higher pumping rates that just increase the WHTP are not necessary. A pumping rate between 8 and 12 BPM (1.12-1.68 MTM), with proper gelling agents in the fluid, will divert the fluid to the perforated intervals and maintain a reasonable WHTP. By holding a constant pumping rate and allowing the diverter to do its job, the WHTP should increase and break back as the diverter works. Maximum pressure should be reached toward the end of the treatment if enough diverter is pumped properly.

12. At ultra-high pumping rates, treating an 800- to 1000-foot (240-300 m) interval is realistic. One way to obtain ultra-high pumping rates in new wells is to pull the tubing out of the hole and pump down the casing. By pumping down the casing, WHTP

pressure would be approximately 5000 psi (34,500 kPa) at pumping rates up to 100 BPM (16 m^3/min). Ultra-high pumping rates may not be an option in older wells due to bad casing, inadequate cement, or a combination of both. Increasing pumping rates down 2-7/8-inch-diameter (7-cm) tubing will only increase the WHTP, not the BHTP. Changing out the 2-7/8- to 3-1/2-inch-diameter (7-9-cm) tubing to increase pumping rates may not be cost effective. There will be a rate increase with the larger diameter pipe, but friction is still a significant problem. When treating down the tubing, an adequate pumping rate must be maintained and the pressure allowed to increase on its own due to the diversion and sealing of perforations. Successful treatment requires that enough diverter and sufficient fluid is pumped to treat all of the perforated beds in the interval.

13. High-rate, hydraulic-fracture treatments are a viable option; this overlooked completion technique should be considered for newer wells.

14. The TDT and anisotropy logs appear to be reliable tools for evaluating remaining hydrocarbon potential and fracture density in a cased-hole well that has been producing oil for many years. This type of data can be used to identify potentially productive beds that are not perforated in older wells, eliminate the acidizing of previously perforated beds that have little to no potential, and determine if the acid fracture treatment is hydraulically fracturing the formation.

15. Based on the UGS/DOE-funded Bluebell field demonstration project (Morgan and Deo, 1999; Morgan, 2003b), we further recommend the following:

    - Use a dual packer tool instead of a retrievable packer and bridge plug so several beds can be treated in one day to greatly reduce the completion cost.

    - Set the packers between perforated intervals that are at least 50 feet (15 m) apart to reduce the risk of communication behind the casing.

    - Use the anisotropy and TDT logs to select beds that are fractured and have relatively low water saturation.

    - Use a treating pressure high enough to fracture the formation, especially if the anisotropy log indicates that some of the beds being treated do not have open fractures.

16. Produced high-paraffin oil is stored on location in insulated tanks and the production facilities have a heat treater that keeps the oil above the pour point temperature. Screen cones are placed on the heat treater stacks to prevent birds from getting into the stacks. Three types of pumps are commonly used in field trend: (1) the standard pump jack, both center and rear gearbox, (2) the submersible pump, and (3) the rotary-flex pump. Water production is a significant part of the operating costs, but a water gathering system with water-injection wells enables disposal of 90% of the produced water at a significant cost savings. Fluids from testing and recompletion operations now go into metal pit tanks prior to disposal.

17. Although production is in decline in the Altamont-Bluebell-Cedar Rim field trend, numerous wells have many productive beds that have not been fully exploited. As a result, production should continue from the area for many decades if these beds can be identified and effectively drained. In December 2008, the Utah Division of Oil, Gas and Mining approved four producing wells per section. The infill drilling could greatly increase production from the field, significantly extend the life of the field, and potentially lead to enhanced oil recovery. Enhanced oil recovery has not been attempted in the field trend because the extensive fracturing in the reservoir would make EOR very unpredictable and could result in early breakthrough of any injected fluids or gases (John Pully, Devon Energy Corporation, verbal communication, 2004).

18. To enhance production and ultimate recovery from the waterflood units in the Red Wash-Wonsits Valley producing trend of the eastern part of the Uinta Basin, the following completion and reservoir management practices should be employed: convert all geophysical well logs into digital form allowing extensive mapping, correlating, and construction of cross sections; conduct generally much smaller fracture treatments than in the past to ensure that the induced fractures do not extend vertically out of the intended zone; fingerprint oil samples from each producing zone to determine the percentage these zones contribute to the overall production of the well; run spinner surveys biannually to determine which zones are producing water; map producing zones including oil and water production to determine the advance of the waterfront for each zone and identify areas that may be by-passed by the flood; and drill on 80-acre (32-ha) spacing to prevent rapid water breakthrough. The estimated secondary recovery using a waterflood program in Red Wash-Wonsits Valley fields is 79.4 million bbls of oil (12.6 million m^3).

19. Three-dimensional seismic has been successfully used in many hydrocarbon plays. Since fractures, not structure or stratigraphy, is a dominant control on reservoir performance, 3D seismic has not been used in the Altamont-Bluebell-Cedar Rim fields. High-angle wells have been drilled but have not resulted in improved production. Horizontal drilling has not been attempted because of the large gross productive interval; no single bed is considered a primary objective. Reservoir characterization has improved over the years but is still greatly hampered by the complex nature of the reservoir and limited amount of data.

20. Secondary and tertiary recovery methods have not been attempted in the Altamont-Bluebell-Cedar Rim field area. Enhanced oil recovery methods generally require a high density of wells to be effective. The Altamont-Bluebell-Cedar Rim field area has been developed with two wells per section and in many areas at least one of those wells has already been plugged and abandoned. As a result, any enhanced oil recovery method would require a significant amount of additional deep drilling.

Conventional Southern Uinta Basin play: To reduce operating costs, enhance production, and increase ultimate recovery from greater Monument Butte field of the Conventional Southern Uinta Basin play, the following completion and reservoir management practices should be employed:

1. The operators should own the drilling rigs ensuring availability and that costs are less than contracting.

2. The operators should purchase frac tanks to reduce the cost of the fracture treatments.

3. Sandstone beds with more than 8% neutron porosity should be selected for perforation, and stimulation of individual beds should begin with the lowermost perforated bed.

4. Completed wells should be placed on primary production using artificial lift.

5. Wells should be converted relatively soon to secondary waterflooding to maintain reservoir pressure above the bubble point in order to maximize oil recovery.

6. Waterflood units should be developed using an alternating injector – producer pattern on 40-acre (16-ha) spacing.

7. Producing wells should be recompleted by perforating all beds that are productive in the waterflood unit.

8. Operators should hire people who can work closely with the regulatory agencies involved.

9. Several drilling options should be available so if environmental issues delay some parts, there are other drilling activities that can be pursued.

10. Horizontal drilling has not been used because of the number of productive beds within a single well and vertical wells at 20-acre spacing (8-ha) are adequately draining the reservoir.

11. Parts of the Greater Monument Butte field have been under waterflood for many years. As a result, EOR techniques such as CO_2 flooding should be investigated.

Paradox Basin Plays

Mississippian Leadville Limestone play:

1. Lisbon field, San Juan County, Utah accounts for most of the Leadville oil production in the Paradox Basin. The Lisbon trap is an elongate, asymmetric, northwest-trending anticline bounded on the northeast flank by a major, basement-involved normal fault. Several minor, northeast-trending normal faults divide the Leadville reservoir into segments. Big Flat field, Grand County, Utah, was the first Mississippian discovery in the Paradox Basin. The trap is a non-faulted, north-south-trending anticline. The Leadville reservoir was abandoned in 1968 after producing just over 83,000 bbls of oil (13,000 m^3) from three wells.

2. Lisbon field has a thick hydrocarbon column, which contains a gas cap and oil ring. Associated, lean, processed, sour gas was reinjected into the gas cap to maintain reservoir pressure and maximize the oil recovery. Gas-sweetening, nitrogen-injection, and helium-recovery facilities were installed in 1992, and in 1993 the operator began gas cap blowdown and sale of residue gas. Big Flat field did not have a gas cap and there were no attempts to maintain reservoir pressure or increase recovery through secondary or tertiary methods.

3. Best practices included drilling wells with air or fresh-water mud to the top of the Paradox Formation salt, after which a natural brine or salt-base mud was typically used to total depth. The wells were completed by usually perforating, at four shots per foot, porosity zones in the Leadville Limestone. The typical completion treatment included stimulation of perforated intervals with 15% HCl acid.

4. Horizontal drilling technology was not readily available when Lisbon field and other Leadville fields were discovered and developed. If horizontal technology had been available, Leadville fields could have been developed with fewer wells (especially in environmentally sensitive areas), and would have resulted in a greater ultimate oil recovery.

5. Lithologic variations due to facies changes, diagenetically increased porosity zones due to dolomitzation, and fractures create potential undrained compartments ideally suited for horizontal drilling in the Leadville-producing fields. Drilling techniques should include new wells and horizontal, often multiple and stacked, laterals from existing vertical wells. Multiple laterals are recommended where separate, geologically distinct zones are present and to avoid topographic features.

Pennsylvanian Paradox Formation play:

1. The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play. The Paradox Formation has produced over 500 million bbls (80 million m^3) of sweet, paraffinic oil and 650 BCFG (18 billion m^3) from more than 70 fields. The main producing zones are referred to as the Cane Creek, Desert Creek, and Ismay. The Paradox Formation oil play area includes nearly the entire Paradox Basin. The Paradox Formation Play is divided into four subplays: (1) fractured Cane Creek shale, (2) Blanding sub-basin Desert Creek zone, (3) Blanding sub-basin Ismay zone, and (4) Aneth platform Desert Creek zone.

2. Drilling in the Paradox Formation may be vertical, deviated, or horizontal. Wells are drilled with a fresh water mud to the top of the Paradox Formation salt, after which a natural brine, salt-based mud, or gel-based mud is typically used to total depth. Severe water flows can occur in both the Permian DeChelly and Jurassic Navajo Sandstones. Wells are drilled to total depth either through the Ismay zone and into the Gothic shale, or through the Desert Creek zone and into either the Chimney Rock shale or salt at the top of the Akah zone, and are evaluated with standard suites of geophysical logs. Vertical wells are completed with matrix-acid stimulations. Fracturing is occasionally performed

in low-permeability reservoir units.

3. To enhance production and ultimate recovery from the McClean field area in the eastern Paradox Basin, Colorado, the following drilling, development, and production practices should be employed: before penetrating the overpressured Desert Creek zone during drilling operations, increase the mud weight to 12.5 pounds (5.7 kg); centralize treatment facilities; mix produced water from pumping oil wells with non-reservoir water and inject the mixture into the reservoir downdip to reduce salt precipitation, dispose of produced water, and maintain reservoir pressure, creating a low-cost waterflood.

4. Three significant late-term development practices were, or could be, employed in the later development of fields in the Paradox Formation play to enhance the ultimate recovery of oil: (1) horizontal drilling, (2) waterfloods, and (3) CO_2 floods.

5. To plan horizontal wells, it is critical to identify and correlate depositional lithofacies, parasequences, and fracture trends in individual Paradox reservoirs in order to understand their effects on water/carbon dioxide injection programs, production rates, and paths of petroleum movement.

6. Horizontal drilling techniques include new wells and horizontal, often multiple, laterals from existing vertical wells. At the well site, careful collection and examination of drill samples (cuttings) during horizontal drilling operations can determine porosity types, mineralogy, and lithofacies being drilled. These properties should be documented and accurately logged to accompany mudlogging data. Ultraviolet- and blue-light fluorescence microscopy can assist with the evaluation of oil shows while drilling the horizontal leg(s).

7. Strategies for horizontal drilling involve drilling stacked, parallel, horizontal laterals. Depositional lithofacies are targeted in both the Ismay and Desert Creek zones where, for example, multiple buildups can be penetrated with two opposed sets of stacked, parallel horizontal laterals. Much of the elongate, brecciated, beach-mound depositional lithofacies in the Desert Creek zone could be penetrated by opposed sets of stacked, parallel, horizontal laterals. Similarly, a second strategy involves penetrating multiple zones of diagenetically enhanced reservoir intervals in these mound buildups. Horizontal drilling increases the probability of encountering the near-vertical fractures needed for economic oil production and has a high success rate in the fractured shale subplay. Prior to 1991, oil had only been produced from vertical wells in the Cane Creek shale. Since then, wells completed in the Cane Creek have used horizontal drilling technology. Horizontal drilling in the Cane Creek has resulted in numerous new field discoveries and greatly improved the success rate of new economical discoveries.

8. Waterfloods are the most common type of secondary oil recovery technique in the Paradox Basin. Depth, drive mechanisms, and water, oil, and gas saturations are major factors to determine candidate reservoirs for waterflood programs. The higher the initial GOR, the poorer the oil recovery from waterflooding. Generally, the initial GOR for Paradox Formation reservoirs is less than 1000 cubic feet/bbl. Low-pressure, low-GOR

reservoirs often have waterflood-to-primary-oil-recovery ratios in excess of 2:1. Very few Paradox reservoirs have higher than normal pressure with most in the 1600 to 2200 psi (11,000-15,000 kPa) range. Water-drive reservoirs are usually not good candidates for waterflooding. The drive mechanisms for most Paradox reservoirs are solution gas, gas expansion, fluid expansion, or pressure depletion.

9. The waterflood program in the Aneth unit of Greater Aneth field now uses horizontal laterals in a line-drive injection pattern which improves both areal and vertical sweep efficiencies over vertical wells. Production and injection laterals are drilled into the Desert Creek porosity zones to sweep oil that vertical wells could not reach.

10. Carbon dioxide flooding is relatively low risk, significantly increases oil recovery, and extends the life of a field by 20 to 30 years. Ultimate oil recovery may increase by over 40% with CO_2 flooding (8 to 16% due to CO_2 flooding alone). Carbon dioxide miscibility needs to be attainable over a major portion of the reservoir requiring widespread good injectivity and reservoir connectivity. Therefore, understanding reservoir lithofacies, heterogeneity, and petrophysical properties is critical in planning CO_2 flooding programs. The reservoir should be deeper than 2500 feet (760 m) and the API gravity of the oil greater than 25º. The depth to the Ismay and Desert Creek zones generally ranges from 5320 to 5920 feet (1620-1800 m); the API gravity of Paradox Formation oils ranges from 38º to 53º. The maximum viscosity must be 10 to 12 cP; the viscosity of Greater Aneth oil is 0.54 cP. Prospective CO_2 flooding candidates should first perform well during waterflood programs. If production water cut reaches 98%, especially during waterfloods, operators likely lose the ability to borrow capital against future production and CO_2 flooding becomes uneconomic. It is also important to recognize that CO_2 prices fluctuate in response to crude oil prices.

11. A reliable source of CO_2 must be available for long-term CO_2 flooding programs. The Devonian Ouray Formation and Mississippian Leadville Limestone, at McElmo Dome field on the eastern edge of the Paradox Basin in southwest Colorado, supply CO_2 to Greater Aneth field. With only the one pipeline in the Paradox Basin, sources of CO_2 may have to be obtained by drilling. Several in-field exploratory wells have tested gas containing CO_2 concentrations of 80% or higher from the Ouray and Leadville. Another potential source of CO_2 is emissions from coal-fired power plants.

12. Carbon dioxide flooding began in the McElmo Creek unit of Greater Aneth in 1985. The production response was between one and two years through a WAG program. Oil production increased from 5500 BOPD to 6500 BOPD (880-1030 m^3/d) peaking after a ten-year period. Incremental recovery from CO_2 flooding is estimated at 33 million BO (5.3 million m^3) or an incremental recovery efficiency of 9.3%. Horizontal wells in the Aneth unit may also be used for CO_2 flooding; however, horizontal laterals need to be oriented parallel to fault/fracture zones to prevent rapid breakthrough.

13. Reservoir 3-D modeling and simulation should be major components in designing waterflooding and CO_2 flood programs for Paradox Formation. High-speed, state-of-the-art computer capability requires accurate and detailed geologic characterization and

reservoir engineering data to predict waterflood and CO_2 flood performance. Numerical simulations illustrate the significant impacts of parasequence boundaries and reservoir heterogeneity created by shale, anhydrite, and low-permeability carbonate rocks common in the Paradox Formation. Results of 3-D modeling and numerical simulation can (1) estimate oil recovery and water cut, (2) determine the spacing and pattern of vertical wells, and (3) predict the viability of horizontal wells in waterflood and CO_2 flood programs.

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APPENDIX A - TECHNOLOGY TRANSFER
Project Presentations

"Major Oil Plays of Utah and Vicinity," by Thomas C. Chidsey, Jr., presented to the Wyoming State Geological Survey, Laramie, Wyoming, September 12, 2002. Maps, cross sections, diagrams, and other information were part of the presentation.

"Major Oil Plays of Utah and Vicinity," by Thomas C. Chidsey, Jr., describing project goals, tasks, and products, to the Uinta Basin Oil and Gas Collaborative Group, Vernal, Utah, December 5, 2002. Maps, cross sections, diagrams, and other information were part of the presentation.

"Major Oil Plays of Utah and Vicinity," by Thomas C. Chidsey, Jr., describing project goals, tasks, and products, to (1) the members of the Technical Advisory Board in Colorado, and (2) the Colorado Geological Survey, Denver, Colorado, February 2003. Maps, cross sections, diagrams, and other information were part of the presentations.

"Outcrop Analogs in Utah – Templates for Reservoir Characterization and Modeling" by Thomas C. Chidsey, Jr., Craig D. Morgan, and Kevin McClure, American Association of Petroleum Geologists Annual Convention, Dallas, Texas, April 20, 2004. Reservoir outcrop analogs included the Mississippian Madison Limestone, Pennsylvanian Paradox Formation, Jurassic Navajo Sandstone and Twin Creek Limestone, and Tertiary Green River Formation.

"Basin-wide Correlation of Petroleum Plays and Subplays in the Green River Petroleum System, Uinta Basin, Utah" by Craig D. Morgan and Kevin McClure, AAPG Rocky Mountain Section Meeting/Rocky Mountain Natural Gas Strategy Conference and Investment Forum (hosted by the Colorado Oil & Gas Association), August 9-11, 2004, in Denver, Colorado. The poster presented plays and subplays bounded by key marker beds, identified on geophysical well logs, representing time lines between which reservoir rocks of the Tertiary Green River Formation were deposited.

"The Jurassic Navajo Sandstone Central Utah Thrust Belt Exploration Play, Sevier County, Utah" by Thomas C. Chidsey, Jr., Richfield, Utah, March 1, 2005, to the Sevier County Commissioners and Community & Economic Development Director. The petroleum geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, and the economic impact on the county were part of the presentation.

"The Jurassic Navajo Sandstone Central Utah Thrust Belt Exploration Play, Sanpete and Sevier Counties, Utah" by Thomas C. Chidsey, Jr., Manti, Utah, May 3, 2005, to the Sanpete County Commissioners and general public. The petroleum geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, and the economic impact on the county were part of the presentation.

"Oil and Gas in Sevier County" panel discussion chaired by the Sevier County Community & Economic Development Director at the Central Utah Economic Summit, Richfield, Utah, May 6, 2005. Thomas C. Chidsey, Jr. served on the panel at this public event where the petroleum

geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, and the economic impact on the county were the focus of the discussion.

"Current Oil and Gas Program of the Utah Geological Survey" by Thomas C. Chidsey, Jr., at the Society of Petroleum Engineers, Salt Lake Petroleum Section, "Gas and Oil Developments in Utah: 2005 Update" symposium in Salt Lake City, Utah, May 20, 2005. The presentation reviewed DOE-funded UGS projects including the PUMPII (the subject of this report), Class II Oil Revisit Paradox Basin horizontal drilling, and the Advanced and Key Oilfield Technologies for Independents (Area 2 – Exploration) Leadville Limestone studies.

"Overview of Potential Energy Resource Development in Utah" panel presentation to the Natural Resources, Agriculture, and Environment Interim Committee, Utah State Legislature, in Salt Lake City, Utah, June 15, 2005. Thomas C. Chidsey, Jr. served on the panel at this open meeting where the petroleum geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, and the economic impact on the State were part of the presentation and discussion.

"Exploration History and Petroleum Geology of the Central Utah Thrust" by Douglas A. Sprinkel and Thomas C. Chidsey, Jr., at the AAPG Rocky Mountain Section Meeting, Jackson, Wyoming, September 26, 2005. The exploration history, petroleum geology, oil source and migration, the Covenant field discovery, and potential of the central Utah thrust belt Navajo Sandstone oil play were part of the presentation.

"The Jurassic Navajo Sandstone Central Utah Thrust Belt Exploration Play" by Thomas C. Chidsey, Jr., Cedar City, Utah, February 6, 2006, to the Iron County (Utah) Comprehensive Land Use Planning Project Working Committee, Iron County Commissioners, and general public. The petroleum geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, land-use issues, and the economic impact on Iron County were part of the presentation.

"The Jurassic Navajo Sandstone Central Utah Thrust Belt Exploration Play, Millard County, Utah" by Thomas C. Chidsey, Jr., Delta, Utah, February 23, 2006, to the Great Basin Historical Society and general public. The petroleum geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, land-use issues, and the economic impact on Millard County were part of the presentation.

"Exploration History and Petroleum Geology of the Central Utah Thrust Belt" by Douglas A. Sprinkel and Thomas C. Chidsey, Jr., April 6, 2006, at the Guy F. Atkinson Lecture Series, University of Utah, Salt Lake City, Utah. The exploration history, petroleum geology, oil source and migration, the Covenant field discovery, and potential of the central Utah thrust belt Navajo Sandstone oil play comprised the presentation.

"Major Oil Plays in San Juan County" by Roger L. Bon, May 15, 2006, to the San Juan County Commissioners and general public, Monticello, Utah. The petroleum geology of the Paradox Basin, play potentials, land-use issues, and the economic impact on the counties were the focus of the discussion.

"Utah's Petroleum Systems, Enhanced Oil Recovery, and Opportunities for CO_2 Sequestration" by Richard G. Allis, May 23, 2006, at the Interstate Oil & Gas Compact Commission Midyear Issues Summit, Billings, Montana. Utah's exploration history and an overview of the petroleum geology of the major plays and their potential were part of the presentation.

"Discovering Oil in Old Wells: Recent Success in the Roosevelt Unit and Bluebell Field, Uinta Basin, Utah" by C.D. Morgan, June 13, 2006, at the AAPG Rocky Mountain Section Meeting, Billings, Montana. An overview of Uinta Basin oil plays, the geology of Bluebell field, and best practices were included in the presentation.

"Discovering Oil in Old Wells: Recent Success in the Roosevelt Unit and Bluebell Field, Uinta Basin, Utah" by C.D. Morgan, September 13, 2006, at the American Petroleum Institute Rocky Mountain Section Meeting, Roosevelt, Utah. An overview of Uinta Basin oil plays, the geology of Bluebell field, and best practices were included in the presentation.

"Gas and Oil in Utah: Potential, New Discoveries, and Hot Plays" by T.C. Chidsey, November 9, 2006, presented at the fall Utah Alumni Meeting sponsored by BP America Producing Company and Brigham Young University, Houston, Texas. An overview of major Utah oil plays, and the geology and potential of the new central Utah thrust belt play were included in the presentation.

"Current Highlights of Major Oil and Gas Plays in Utah" by T.C. Chidsey, March 1, 2007, presented at the monthly meeting of the Utah Association of Professional Landmen in Salt Lake City, Utah. An overview of major Utah oil plays, and the geology and potential of the new central Utah thrust belt play were included in the presentation.

"Covenant Oil Field, Central Utah Thrust Belt – Possible Harbinger of Future Discoveries" by Thomas C. Chidsey, Jr., Michael D. Laine, John P. Vrona, and Douglas K. Strickland, at the AAPG Annual Convention, Long Beach, California, April 2, 2007. Displays of Navajo Sandstone reservoir cores, the petroleum geology, reservoir facies, petrophysical properties, and oil source of the Covenant field discovery, and potential of the central Utah thrust belt Navajo Sandstone oil play were part of the presentation.

"Exploration and Petroleum Geology of the Central Utah Hingeline" by Thomas C. Chidsey, Jr., Douglas A. Sprinkel, and Michael D. Laine, at the Geological Society of America Rocky Mountain Section meeting, St. George, Utah, May 8, 2007. The exploration history, petroleum geology, oil source and migration, the Covenant field discovery, and potential of the central Utah thrust belt Navajo Sandstone oil play were part of the presentation.

"Gas and Oil in Utah: Potential, New Discoveries, and Hot Plays" by Thomas C. Chidsey, Jr., presented at the annual meeting of the International Oil Scouts Association in Park City, Utah, June 19, 2007. An overview of major Utah oil plays, and the geology and potential of the new central Utah thrust belt play were included in the presentation.

"The Jurassic Navajo Sandstone Central Utah Thrust Belt Exploration Play, Sanpete County, Utah" by Thomas C. Chidsey, Jr., Manti, Utah, July 17, 2007, to the Sanpete County

Commissioners, county planners, and general public. The petroleum geology of the central Utah thrust belt play, the recent oil discovery of Covenant field, play potential, and the economic impact on the county were part of the presentation.

"Covenant Oil Field, Central Utah Thrust Belt – Possible Harbinger of Future Discoveries" by Michael D. Laine, Thomas C. Chidsey, Jr., John P. Vrona, and Douglas K. Strickland, at the AAPG Rocky Mountain Section meeting, Snowbird, Utah, October 8, 2007. Displays of Navajo Sandstone reservoir cores, the petroleum geology, reservoir facies, petrophysical properties, and oil source of the Covenant field discovery, and potential of the central Utah thrust belt Navajo Sandstone oil play were part of the presentation.

"Why Modelers Need to Look at the Rocks! – Examples from Greater Aneth Field, Paradox Basin, Utah" by Thomas C. Chidsey, Jr., David E. Eby, Michael D. Laine, and Thomas Dempster, at the AAPG Rocky Mountain Section meeting, Snowbird, Utah, October 9, 2007. Displays of Paradox Formation cores representing reservoir facies, baffles, and seals, and how they are needed in modeling and simulation studies were part of the presentation.

"Enhanced Oil Recovery Potential in the Uinta Basin, Utah" by Craig D. Morgan and Milind Deo, at the AAPG Rocky Mountain Section meeting, Snowbird, Utah, October 8, 2007. The presentation described waterflood operations, well spacing, carbon dioxide flooding, and reaming potential in the basin that requires enhanced oil recovery technology.

Project Publications

Abstracts

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Morgan, C.D., and McClure, K., 2004, Basin-wide correlation of petroleum plays and subplays in the Green River petroleum system, Uinta Basin, Utah [abs.]: American Association of Petroleum Geologists, Rocky Mountain Section Meeting Official Program Book, p. 110 and 112.

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Chidsey, T.C., Jr., Laine, M.D., Vrona, J.P., and Strickland, D.K., 2007, Covenant oil field, central Utah thrust belt – possible harbinger of future discoveries [abs.]: American Association of Petroleum Geologists Annual Convention Abstracts, v. 16, p. 24.

Chidsey, T.C., Jr., Sprinkel, D.A., and Laine, M.D., 2007, Exploration and petroleum geology of the central Utah Hingeline [abs.]: Abstracts with Programs, Geological Society of America 59th Annual Rocky Mountain Section Meeting, v. 39, no. 5, paper 14-7, p. 35.

Chidsey, T.C., Jr., Eby, D.E., Laine, M.D., and Dempster, J.T., 2007, Why modelers need to look at the rocks! – examples from Greater Aneth field, Paradox Basin, Utah [abs.]: American Association of Petroleum Geologists, Rocky Mountain Section Meeting Official Program, p. 35.

Laine, M.D., Chidsey, T.C., Jr., Sprinkel, D.A., Vrona, J.P., and Strickland, D.K., 2007, Covenant oil field, central Utah thrust belt – possible harbinger of future discoveries [abs.]: American Association of Petroleum Geologists, Rocky Mountain Section Meeting Official Program, p. 45.

Morgan, C.D., and Deo, M., 2007, Enhanced oil recovery potential in the Uinta Basin, Utah [abs.]: American Association of Petroleum Geologists, Rocky Mountain Section Meeting Official Program, p. 49.

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Chidsey, T.C., Jr., Wakefield, S., Hill, B.G., and Hebertson, M., 2004, Oil and gas fields of Utah: Utah Geological Survey Map 203DM, scale 1:700,000.

Sprinkel, D.A., and Chidsey, T.C., Jr., 2006, Exploration history and petroleum geology of the central Utah thrust belt: Online, American Association of Petroleum Geologists Search and Discovery Article No. 10103, <http://www.searchanddiscovery.net/documents/2006/06028sprinkel/index.htm>, posted May 13, 2006.

Chidsey, T.C., Jr., Laine, M.D., Vrona, J.P., and Strickland, D.K., 2007, Covenant oil field, central Utah thrust belt – possible harbinger of future discoveries: Online, American Association of Petroleum Geologists Search and Discovery Article No. 10130, <http://www.searchanddiscovery.net/documents/2007/07070chidsey/index.htm>, posted July 30, 2007.

Chidsey, T.C., Jr., DeHamer, J.S., Hartwick, E.E., Johnson, K.R., Schelling, D.D., Sprinkel, D.A., Strickland, D.K., Vrona, J.P., and Wavrek, D.A., 2007, Petroleum geology of Covenant oil field, central Utah thrust belt, *in* Willis, G.C., Hylland, M.D., Clark, D.L., and Chidsey, T.C., Jr., editors, Central Utah – diverse geology of a dynamic landscape: Utah Geological Association Publication 36, p. 273-296.

Morgan, C.D., in preparation, Greater Monument Butte oil field – infill drilling results and potential CO2 enhanced oil recovery, *in* Longman, M.W., Gustason, E.R., and Morgan, C.D., editors, Hydrocarbon systems and production in the Uinta Basin, Utah: Rocky Mountain Association of Geologists-Utah Geological Association Guidebook.

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Chidsey, T.C., Jr., 2002, UGS to produce play portfolios of major oil provinces: Utah Geological Survey Petroleum News, p. 6.

Chidsey, T.C., Jr., 2002, UGS awarded DOE grant to produce play portfolios of Utah's major oil provinces: Utah Geological Survey, Survey Notes, v. 34, no. 1, p. 11.

Chidsey, T.C., Jr., and Wakefield, S., 2004, New oil and gas fields map of Utah – just the facts!: Utah Geological Survey, Survey Notes, v. 36, no. 3, p. 8-9.

Chidsey, T.C., Jr., and Wakefield, S., 2004, New oil and gas fields map of Utah: U.S. Department of Energy, The Class Act, v. 10, no. 1, p. 1-3.

Chidsey, T.C., Jr., and Sprinkel, D.A., 2005, "Elephant" discovered in central Utah: Utah Geological Survey, Survey Notes, v. 37, no. 2, p. 8-9.

Utah Geological Survey, 2006, Utah! 100 years of exploration… and still the place to find oil and gas: Utah Geological Survey Public information Series 71, 20 p.

Quarterly Technical Progress Reports

Chidsey, T.C., Jr., 2003, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period July 1 to September 30, 2002: U.S. Department of Energy, DOE/FC26-02NT15133-1, 23 p.

Chidsey, T.C., Jr., 2003, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period October 1 to December 31, 2002: U.S. Department of Energy, DOE/FC26-02NT15133-2, 15 p.

Chidsey, T.C., Jr., Morgan, C.D., and Bon, R.L., 2003, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period January 1 to March 31, 2003: U.S. Department of Energy, DOE/FC26-02NT15133-3, 18 p.

Chidsey, T.C., Jr., Morgan, C.D., McClure, Kevin, and Willis, G.C., 2003, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period April 1 to June 30, 2003: U.S. Department of Energy, DOE/FC26-02NT15133-4, 38 p.

Morgan, C.D., and Chidsey, T.C., Jr., 2003, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period July 1 to September 30, 2003: U.S. Department of Energy, DOE/FC26-02NT15133-5, 46 p.

Chidsey, T.C., Jr., Morgan, C.D., McClure, K., Sprinkel, D.A., Bon, R.L., and Doelling, H.H., 2004, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period October 1 to December 31, 2003: U.S. Department of Energy, DOE/FC26-02NT15133-6, 63 p.

Chidsey, T.C., Jr., Morgan, C.D., McClure, K., Bon, R.L., Gwynn, J.W., Jarrard, R., and Curtice, R., 2004, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period January 1 to March 31, 2004: U.S. Department of Energy, DOE/FC26-02NT15133-7, 31 p.

Chidsey, T.C., Jr., Morgan, C.D., and Bon, R.L., 2004, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period April 1 to June 30, 2004: U.S. Department of Energy, DOE/FC26-02NT15133-8, 22 p.

Chidsey, T.C., Jr., and Sprinkel, D.A., 2004, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period July 1 to September 30, 2004: U.S. Department of Energy, DOE/FC26-02NT15133-9, 26 p.

Chidsey, T.C., Jr., and Sprinkel, D.A., 2005, Major oil plays in Utah and vicinity – quarterly annual technical progress report for the period October 1 to December 31, 2004: U.S. Department of Energy, DOE/FC26-02NT15133-10, 44 p.

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Chidsey, T.C., Jr., and Morgan, C.D., 2005, Major oil plays in Utah and vicinity – quarterly technical progress report for the period April 1 to June 30, 2005: U.S. Department of Energy, DOE/FC26-02NT15133-12, 61 p.

Chidsey, T.C., Jr., and Morgan, C.D., 2005, Major oil plays in Utah and vicinity – quarterly technical progress report for the period July 1 to September 30, 2005: U.S. Department of Energy, DOE/FC26-02NT15133-13, 27 p.

Chidsey, T.C., Jr., and Morgan, C.D., 2006, Major oil plays in Utah and vicinity – quarterly technical progress report for the period October 1 to December 31, 2005: U.S. Department of Energy, DOE/FC26-02NT15133-14, 57 p.

Chidsey, T.C., Jr., 2006, Major oil plays in Utah and vicinity – quarterly technical progress report for the period January 1 to March 31, 2006: U.S. Department of Energy, DOE/FC26-02NT15133-15, 67 p.

Bon, R.L., and Chidsey, T.C., Jr., 2006, Major oil plays in Utah and vicinity – quarterly technical progress report for the period April 1 to June 30, 2006: U.S. Department of Energy, DOE/FC26-02NT15133-16, 68 p.

Chidsey, T.C., Jr., and Sprinkel, D.A., 2006, Major oil plays in Utah and vicinity – quarterly technical progress report for the period July 1 to September 30, 2006: U.S. Department of Energy, DOE/FC26-02NT15133-17, 38 p.

Chidsey, T.C., Jr., 2007, Major oil plays in Utah and vicinity – quarterly technical progress report for the period October 1 to December 31, 2006: U.S. Department of Energy, DOE/FC26-02NT15133-18, 19 p.

Chidsey, T.C., Jr., 2007, Major oil plays in Utah and vicinity – quarterly technical progress report for the period January 1 to March 31, 2007: U.S. Department of Energy, DOE/FC26-02NT15133-19, 19 p.

Chidsey, T.C., Jr., 2007, Major oil plays in Utah and vicinity – quarterly technical progress report for the period April 1 to June 30, 2007: U.S. Department of Energy, DOE/FC26-02NT15133-20, 17 p.

Chidsey, T.C., Jr., Morgan, C.D., and Eby, D.E., 2008, Major oil plays in Utah and vicinity – quarterly technical progress report for the period July 1 to September 30, 2007: U.S. Department of Energy, DOE/FC26-02NT15133-21, 53 p.

Chidsey, T.C., Jr., 2008, Major oil plays in Utah and vicinity – quarterly technical progress report for the period October 1 to December 31, 2007: U.S. Department of Energy, DOE/FC26-02NT15133-22, 14 p.

Project Displays at American Association of Petroleum Geologists Annual Meetings

Project materials, plans, objectives, and results were displayed at the UGS booth during the following meetings of the American Association of Petroleum Geologists (AAPG):

AAPG Rocky Mountain Section Meeting, September 8-10, 2002, Laramie, Wyoming
AAPG Annual Convention, May 11-14, 2003, Salt Lake City, Utah
AAPG Annual Convention, April 18-24, 2004, Dallas, Texas
AAPG Rocky Mountain Section Meeting/Rocky Mountain Natural Gas Strategy Conference and Investment Forum (hosted by the Colorado Oil & Gas Association), August 9-11, 2004, in Denver, Colorado
AAPG Annual Convention, June 19-22, 2005, Calgary, Canada
APG Rocky Mountain Section Meeting, September 23-24, 2005, Jackson, Wyoming
AAPG Annual Convention, April 9-12, 2006, Houston, Texas
AAPG Rocky Mountain Section Meeting, June 10-13, 2006, Billings, Montana
AAPG Annual Convention, April 1-4, 2007, Long Beach, California
AAPG Rocky Mountain Section Meeting, October 7-9, 2007, Snowbird, Utah
AAPG Annual Convention, April 20-23, 2008, San Antonio, Texas
AAPG Rocky Mountain Section Meeting, July 9-11, 2008, Denver, Colorado

Field Trip/Core Workshop

During the Utah Geological Association's annual fall field trip (October 10-12, 2007), the project team conducted a geologic stop at Covenant field that included the basic petroleum geology of the field (structure, reservoir/stratigraphy, drilling history, production, reserves, and

oil source). The team later presented a short core workshop of Navajo Sandstone core from Covenant field in Manti, Utah, emphasizing eolian facies and petrophysical properties.

Utah Geological Survey Web Site

The UGS maintains a Web site on the Internet, http://geology.utah.gov. The UGS site includes a page under the heading *Utah Geology/Oil, Coal, and Energy*, which describes the UGS/DOE cooperative studies (PUMPII, Paradox Basin [two projects], Ferron Sandstone, Bluebell field, Green River Formation), and has a link to the DOE Web site. Each UGS/DOE cooperative study also has its own separate page on the UGS Web site. The PUMPII project page, http://geology.utah.gov/emp/pump/index.htm, contains (1) a project location map, (2) a description of the project, (3) a reference list of all publications that are a direct result of the project, (4) poster presentations, and (5) quarterly technical progress reports.

Technical Advisory Board

Sinclair Oil Corp., Salt Lake City, Utah
Flying J Oil & Gas Inc., North Salt Lake City, Utah
Ballard Petroleum Holdings LLC, Billings, Montana
Devon Energy Corporation, Oklahoma City, Oklahoma
Tom Brown Inc., Denver, Colorado
Pioneer Oil & Gas, South Jordan, Utah
Red Willow Production Company, Ignacio, Colorado
Dolar Energy LLC, Midvale, Utah
Questar Exploration, Denver, Colorado
Roger E. Hively, Consulting Geologist, Denver, Colorado
Logan MacMillan, Consulting Geologist, Denver, Colorado

Stake Holders Board

Utah School and Institutional Trust Lands Administration, Salt Lake City, Utah
Utah Division of Oil, Gas and Mining, Salt Lake City, Utah
U.S. Bureau of Land Management, Salt Lake City, Utah
U.S. Bureau of Indian Affairs, Lakewood, Colorado

APPENDIX B - NATIVE AMERICAN TRIBE AND BIA AGENCY CONTACT INFORMATION

Arizona

Navajo Nation
P.O. Box 9000
Window Rock, AZ 86515
Division of Natural Resources
Phone: (928) 871-6592/6593
Fax: (928) 871-7040
http://www.navajo.org/index.htm

*BIA Window Rock Agency
P.O. Box 1060
Gallup, NM 87305
Real Estate Services
Phone: (928) 871-5938
Fax: (928) 871-5943
* also handles mineral leasing in Utah
Web site is unavailable

Colorado

Ute Mountain Ute Indian Tribe
P.O. Box 109
Towaoc, CO 81334
Phone: (800) 258-8007/ (970) 565-8800
Fax: N/A
http://www.utemountainute.com/

Southern Ute Indian Tribe
P.O. Box 737
Ignacio, CO 81137
Phone: (970) 563-0100
Fax: (970) 563-0137 (administration)
http://www.southern-ute.nsn.us/

Utah

Ute Energy, LLC
P.O. Box 789
7074 East 900 South
Fort Duchesne, UT 84026
Phone: (435) 722-0291
Fax: (435) 722-3902
http://uteenergy.com/

BIA Uintah & Ouray Agency
P.O. Box 130
988 South 7500 East
Fort Duchesne, UT 84026
Phone: (435) 722-4300
Fax: (435) 722-2809
Web site is unavailable

Ute Distribution Corp.
P.O. Box 696
24 South 200 East
Roosevelt, UT 84066
Phone: (435) 722-2922
Fax: N/A
No Web site

Ute Indian Tribe
P.O. Box 190
910 South 7500 East
Fort Duchesne, UT 84026
Phone: (435) 722-5141
Fax: N/A
http://www.utetribe.com/

Paiute Indian Tribe of Utah
440 North Paiute Drive
Cedar City, UT 84720
Phone: (435) 586-1112
Fax: (435) 5867388
http://utahpaiutes.org

APPENDIX C - NATIONAL FOREST CONTACT INFORMATION

State/National Forest	Province	Address
Colorado		
San Juan	Paradox Basin	15 Burnett Court Durango, CO 81301 Phone: (970) 247-4874 http://www.fs.fed.us/r2/sanjuan/
Uncompahgre	Paradox Basin	2250 Highway 50 Delta, CO 81416 Phone: (970) 874-6600 http://www.fs.fed.us/r2/gmug/
Utah		
Ashley	Uinta Basin	355 North Vernal Ave Vernal, UT 84078 Phone: (435) 789-1181 http://www.fs.fed.us/r4/ashley/
Fish Lake	Central Utah	115 East 900 North Richfield, UT 84701 Phone: (435) 896-9233 http://www.fs.fed.us/r4/fishlake/
Manti-La Sal	Central Utah/Paradox Basin	599 West Price River Dr. Price, UT 84501 Phone: (435) 637-2817 http://www.fs.fed.us/r4/mantilasal/
Uinta	Central Utah/Uinta Basin	88 West 100 North Provo, UT 84601 Phone: (801) 342-5100 http://www.fs.fed.us/r4/uwc/

APPENDIX D - FEDERAL AGENCIES INVOLVED IN MINERAL LEASING ACTIVITIES

U.S. Department of the Interior

Bureau of Indian Affairs
Office of Indian Energy and Economic Dev.
1951 Constitution Ave. NW
Room 20–South Interior Building
Washington, DC 20245
http://www.bia.gov (currently inactive)

Bureau of Land Management
MAILING ADDRESS: 1849 C St. NW
Washington, DC 20240
STREET ADDRESS: 1620 L St. NW
Washington, DC 20036
http://www.blm.gov/nhp/

Bureau of Reclamation
Washington, DC
1849 C St. NW
Washington, DC 20240
http://www.usbr.gov/

U.S. Fish and Wildlife Service
1849 C St. NW
Washington, DC 20240
Phone: (800) 344-9453
http://www.fws.gov

Minerals Management Service
1849 C St. NW, MS 4243
Washington, DC, 20240
Phone: (202) 208-3500
http://www.mms.gov

Minerals Revenue Management
P.O. Box 25165
Denver Federal Center, Building 85
Denver, CO 80225-0165
Phone: (303) 231-3162
http://www.mrm.mms.gov

U.S. Department of Agriculture

U.S. Forest Service
1400 Independence Ave. SW
Mail Stop 1126 RPC 5
Washington, DC 20250
Phone: (703) 605-4545
Fax: (703) 605-1575
http://www.fs.fed.us/
Web site for Energy Leasable Minerals
http://www.fs.fed.us/geology/mgm_leasable.html

APPENDIX E – SUMMARY OF INSTANT STUDY AREAS (ISA), WILDERNESS AREAS (WA), AND WILDERNESS STUDY AREAS (WSA)

Name	Province	Type	Acres
Dark Canyon ISA Complex	Paradox Basin	ISA	67,825
Grand Gulch ISA Complex	Paradox Basin	ISA	64,960
Book Cliffs Mountain Browse ISA	Uinta Basin	ISA	399
Dark Canyon	Paradox Basin	WA	45,956
Behind the Rocks	Paradox Basin	WSA	13,064
Bridger Jack Mesa	Paradox Basin	WSA	6,333
Butler Wash	Paradox Basin	WSA	24,277
Cheese Box Canyon	Paradox Basin	WSA	14,831
Coal Canyon	Paradox Basin	WSA	3,393
	Uinta Basin	WSA	10,431
Cross Canyon	Paradox Basin	WSA	940
Desolation Canyon	Paradox Basin	WSA	95,599
	Uinta Basin	WSA	231,662
Dirty Devil	Paradox Basin	WSA	53,885
Fiddler Butte	Paradox Basin	WSA	72,560
Fish Creek Canyon	Paradox Basin	WSA	46,102
Floy Canyon	Paradox Basin	WSA	50,667
	Uinta Basin	WSA	14,140
Flume Canyon	Uinta Basin	WSA	27,415
French Spring-Happy Canyon	Paradox Basin	WSA	24,305
Horseshoe Canyon (North)	Paradox Basin	WSA	19,501
Horseshoe Canyon (South)	Paradox Basin	WSA	39,842
Indian Creek	Paradox Basin	WSA	6,554
Jack Canyon	Uinta Basin	WSA	7,203
Little Rockies	Paradox Basin	WSA	303
Lost Spring Canyon	Paradox Basin	WSA	1,625
Mexican Mountain	Paradox Basin	WSA	13,995
Mill Creek Canyon	Paradox Basin	WSA	9,866
Mule Canyon	Paradox Basin	WSA	6,171
Negro Bill Canyon	Paradox Basin	WSA	7,560
Road Canyon	Paradox Basin	WSA	52,404
San Rafael Reef	Paradox Basin	WSA	218
South Needles	Paradox Basin	WSA	160
Spruce Canyon	Uinta Basin	WSA	19,282
Squaw/Papoose Canyon	Paradox Basin	WSA	6,362
Turtle Canyon	Uinta Basin	WSA	33,265
Winter Ridge	Uinta Basin	WSA	43,322
Total			1,136,380

APPENDIX F - U.S. BUREAU OF LAND MANAGEMENT STATE AND FIELD OFFICES

Utah/Wyoming thrust belt

Utah

Utah State Office
440 West 200 South, Ste. 500
Salt Lake City, UT 84145
Phone: (801) 539-4001
Fax: (801) 539-4013
http://www.ut.blm.gov

Salt Lake Field Office
2370 South 2300 West
Salt Lake City, UT 84119
Phone: (801) 977-4300
Fax: (801) 977-4397
http://www.ut.blm.gov/saltlake_fo/

Wyoming

Wyoming State Office
5353 Yellowstone Rd.
Cheyenne, WY 82003
Phone: (307) 775-6256
Fax: (307) 775-6082
http://www.wy.blm.gov/

Kemmerer Field Office
312 Highway 189 North
Kemmerer, WY 83101-9711
Phone: (307) 828-4500
Fax: (307) 828-4539
http://www.wy.blm.gov/kfo/index.htm

Central Utah thrust belt — Hingeline

Utah

Richfield Field Office
150 East 900 North
Richfield, UT 84701
Phone: (435) 896-1500
Fax: (435) 896-1550
http://www.blm.gov/ut/st/en/fo/richfield.html

Salt Lake Field Office
2370 South 2300 West
Salt Lake City, UT 84119
Phone: (801) 977-4300
Fax: (801) 977-4397
http://www.ut.blm.gov/saltlake_fo/

Fillmore Field Office
35 East 500 North
Fillmore, UT 84631
Phone: (435) 743-3100
Fax: (435) 743-3135
http://www.ut.blm.gov/fillmore_fo/

Cedar City Field Office
176 East DL Sargent Drive
Cedar City, UT 84720
Phone: (435) 586-2401
Fax: (435) 865-3058
http://www.ut.blm.gov/cedarcity_fo/

Uinta Basin

Colorado

Colorado State Office
2850 Youngfield Street
Lakewood, CO 80215
Phone: (303) 239-3600
Fax: (303) 239-3933
http://www.co.blm.gov

White River Field Office
73544 Hwy. 64
Meeker, CO 81641
Phone: (970) 878-3800
Fax: (970) 878-3805
http://www.co.blm.gov/wrra/index.htm

Grand Junction Field Office
2815 H Road
Grand Junction, CO 81506
Phone: (970) 244-3000
Fax: (970) 244-3083
http://www.co.blm.gov/gjra/gjra.html

Utah

Utah State Office
440 West 200 South, Ste. 500
Salt Lake City, UT 84145
Phone: (801) 539-4001
Fax: (801) 539-4013
http://www.ut.blm.gov

Salt Lake Field Office
2370 South 2300 West
Salt Lake City, UT 84119
Phone: (801) 977-4300
Fax: (801) 977-4397
http://www.ut.blm.gov/saltlake_fo/

Vernal Field Office
170 South 500 East
Vernal, UT 84078
Phone: (435) 781-4400
Fax: (435) 781-4410
http://www.blm.gov/ut/st/en/fo/vernal.html

Price Field Office
125 South 600 West
Price, UT 84501
Phone: (435) 636-3600
Fax: (435) 636-3657
http://www.blm.gov/utah/price/

Moab Field Office
82 East Dogwood
Moab, UT 84532
Phone: (435) 259-2100
Fax: (435) 259-2106
http://www.blm.gov/ut/st/en/fo/moab.html

Paradox Basin

Arizona and New Mexico

Arizona State Office
One North Central Avenue, Ste. 800
Phoenix, AZ 85004-4427
Phone: (602) 417-9200
Fax: (602) 417-9314
http://www.blm.gov/az/st/en.html

Farmington Field Office
1235 La Plata Highway, Ste. A
Farmington, NM 87401
Phone: (505) 599-8900
Fax: (505) 599-8998
http://www.nm.blm.gov/ffo/ffo_home.html

Colorado

Grand Junction Field Office
2815 H Road
Grand Junction, CO 81506
Phone: (970) 244-3000
Fax: (970) 244-3083
http://www.co.blm.gov/gjra/gjra.html

Uncompahgre Field Office
2505 South Townsend Avenue
Montrose, CO 81401
Phone: (970) 240-5300
Fax: (970) 240-5367
http://www.co.blm.gov/ubra/index.html

Mancos/Dolores Field Office (BLM/USFS)
P.O. Box 210
100 North 6th St.,
Dolores, CO 81323
Phone: (970) 882-7296
Fax: N/A
No Web site

Utah

Price Field Office
125 South 600 West
Price, UT 84501
Phone: (435) 636-3600
Fax: (435) 636-3657
http://www.blm.gov/utah/price/

Moab Field Office
82 East Dogwood, Ste. M
Moab, UT 84532
Phone: (435) 259-2100
Fax: (435) 259-2106
http://www.blm.gov/ut/st/en/fo/moab.html

Richfield Field Office
150 East 900 North
Richfield, UT 84701
Phone: (435) 896-1500
Fax: (435) 896-1550
http://www.blm.gov/ut/st/en/fo/richfield.html

Monticello Field Office
P.O. Box 7
435 North Main St.
Monticello, UT 84535
Phone: (435) 587-1500
Fax: (435) 587- 1518

http://www.blm.gov/ut/st/en/fo/monticello.html

APPENDIX G - LOCATION OF COUNTY COURTHOUSES

Utah/Wyoming thrust belt

Utah

Morgan County Courthouse
48 West Young St.
Morgan, UT 84050
Phone: (801) 845-4006
Fax: (801) 845-6006
http://www.morgan-county.net

Rich County Courthouse
20 South Main St.
Randolph, UT 84064
Phone: (435) 793-2415
Fax: (435) 793-2410
http://www.richcountyut.org

Summit County Courthouse
60 North Main St.
Coalville, UT 84017
Phone: (435) 336-3220
Fax: (435) 336-3030
http://www.co.summit.ut.us

Wyoming

Lincoln County Courthouse
925 Sage Ave.
Kemmerer, WY 83101
Phone: (307) 877-9056
Fax: (307) 877-3101
http://www.lcwy.org

Uinta County Courthouse
225 9th St.
Evanston, WY 82930
Phone: (307) 783-3001
Fax: (307) 783-0511
http://www.uintacounty.com

Central Utah thrust belt — Hingeline

Utah

Beaver County Administration Bldg.
P.O. Box 431
105 East Center St.
Beaver, UT 84713
Phone: (435) 438-6480
Fax: (435) 438-6481
http://www.beaver.state.ut.us

Piute County Courthouse
P.O. Box 116
550 North Main St.
Junction, UT 84740-0116
Phone: (435) 577-2505
Fax: (435) 577-2433
http://www.piute.org

Millard County Courthouse
50 South Main St.
Fillmore, UT 84631-5504
Phone: (435) 743-6210
Fax: (435) 743-4221
http://www.millardcounty.com

Juab County Courthouse
160 North Main St.
Nephi, UT 84648-1412
Phone: (435) 623-3430
Fax: (435) 623-5936
http://www.co.juab.ut.us

Sanpete County Courthouse
160 North Main St.
Manti, UT 84642-1268
Phone: (435) 835-2181
Fax: (435) 835-2182
www.sanpetecounty.org

Sevier County Courthouse
250 North Main St.
Richfield, UT 84701-2156
Phone: (435) 896-9262
Fax: (435) 896-8888
www.sevierutah.net

Utah County Administration Building
100 East Center St., Ste. 1300
Provo, UT 84606
Phone: (801) 851-8179
Fax: (801) 851-8181
http://www.utahcountyonline.org

Uinta Basin

Colorado

Garfield County Courthouse
109 8th St., Ste. 200
Glenwood Springs, CO 81601-3355
Phone: (970) 945-2377
Fax: (970) 947-1078
http://www.garfield-county.com

Rio Blanco County Courthouse
P.O. Box 1067
555 Main St.
Meeker, CO 81641
Phone: (970) 878-9460
Fax: (970) 878-3587
http://www.co.rio-blanco.co.us

Utah

Carbon County Courthouse
120 East Main St.
Price, UT 84501
Phone: (435) 636-3711
Fax: (435) 636-3244
http://www.carbon.utah.gov/

Grand County Courthouse
125 East Center St.
Moab, UT 84532
Phone: (435) 259-1333
Fax: (435) 259-1382
http://www.grandcountyutah.net

Emery County Courthouse
P.O. Box 698
75 East Main St.
Castle Dale, UT 84513
Phone: (435) 381-2414
Fax: (435) 381-2614
http://www.emerycounty.com

Duchesne County Administration
P.O. Box 910
734 North Center St.
Duchesne, UT 84021
Phone: (435) 738-1100
Fax: (435) 738-5522
http://www.duchesnegov.net

Utah County Administration Building
100 East Center St., Ste. 1300
Provo, UT 84606
Phone: (801) 851-8179
Fax: (801) 851-8181
http://www.utahcountyonline.org

Uintah County Building
147 East Main St.
Vernal, UT 84078
Phone: (435) 781-5361
Fax: (435) 781-6701
http://www.co.uintah.ut.us

Morgan County Courthouse
P.O. Box 886
48 West Young St.
Morgan, UT 84050

Wasatch County Administration Bldg
25 North Main St.
Heber City, UT 84032
Phone: (435) 654-3211

Phone: (801) 829-3277
Fax: (801) 829-6176
http://www.morgan-county.net

Fax: (435) 657-0283
http://www.co.wasatch.ut.us

Paradox Basin

Arizona

Apache County Managers Office
County Annex Bldg.
P.O. Box 428
75 West Cleveland
St. Johns, AZ 85936
Phone: (928) 337-4364
Fax: (928) 337-2003
http://www.co.apache.az.us

Colorado

Dolores County Courthouse
P.O. Box 608
409 North Main St.
Dove Creek, CO 81324-0608
Phone: (970) 677-2383
Fax: (970) 677-2815
http://www.dolorescounty.org

Mesa County Courthouse
P.O. Box 20000
544 Rood Ave.
Grand Junction, CO 81502-5006
Phone: (970) 244-1607
Fax: (970) 244-1703
http://www.mesacounty.us

Montezuma County Courthouse
P.O. Box 3142
109 West Main St.
Cortez, CO 81321-3142
Phone: (970) 565-8317
Fax: (970) 565-3420
http://www.co.montezuma.co.us

Montrose County Courthouse
P.O. Box 1289
320 South First St.
Montrose, CO 81402
Phone: (970) 249-3362, ext. 1
Fax: (970) 249-0757
http://www.co.montrose.co.us

San Miguel County Courthouse
P.O. Box 548
305 West Colorado Ave.
Telluride, CO 81435
Phone: (970) 728-3954
Fax: (970) 728-4808
http://www.sanmiguelcounty.org

Utah

Emery County Courthouse
P.O. Box 698
75 East Main St.
Castle Dale, UT 84513

Garfield County Offices
P.O. Box 77
55 South Main St.
Panguitch, UT 84759-0077

Phone: (435) 381-2414
Fax: (435) 381-2614
http://www.emerycounty.com

Grand County Courthouse
125 East Center St.
Moab, UT 84532
Phone: (435) 259-1333
Fax: (435) 259-1382
http://www.grandcountyutah.net

Wayne County Courthouse
P.O. Box 189
18 South Main St.
Loa, UT 84747
Phone: (435) 836-2765
Fax: N/A
http://www.waynecnty.com

Phone: (435) 676-1112
Fax: (435) 676-8239
http://www.garfield-county.com/

San Juan County Courthouse
P.O. Box 789
117 South Main St.
Monticello, UT 84535
Phone: (435) 587-3228
Fax: (435) 587-2425
http://www.sanjuancounty.org

APPENDIX H - NATIONAL PARK (NP), NATIONAL MONUMENT (NM), AND NATIONAL RECREATION AREA (NRA) CONTACT INFORMATION

State/ Name	Province	Address
Colorado		
Canyons of the Ancients NM	Paradox Basin	27501 Hwy. 184 Dolores, CO 81323 Phone: (970) 882-5632 http://www.blm.gov/rmp/canm/
Utah		
Arches NP	Paradox Basin	P.O. Box 905 Moab, UT 84532 Phone: (435) 719-2299 http://www.nps.gov/arch/
Canyonlands NP	Paradox Basin	2282 SW Resource Blvd. Moab, UT 84532 Phone: (435) 719-2313 http://www.nps.gov/cany/
Hovenweep NM	Paradox Basin	McElmo Route Cortez, CO 81321 Phone: (970) 562-4282 http://www.nps.gov/hove/
Natural Bridges NM	Paradox Basin	HC-60 Box 1 Lake Powell, UT 84533 Phone: (435) 692-1234 http://www.nps.gov/nabr/
Glen Canyon NRA	Paradox Basin	P.O. Box 1507 Page, AZ 86040 Phone: (928) 608-6200 http://www.nps.gov/glca/

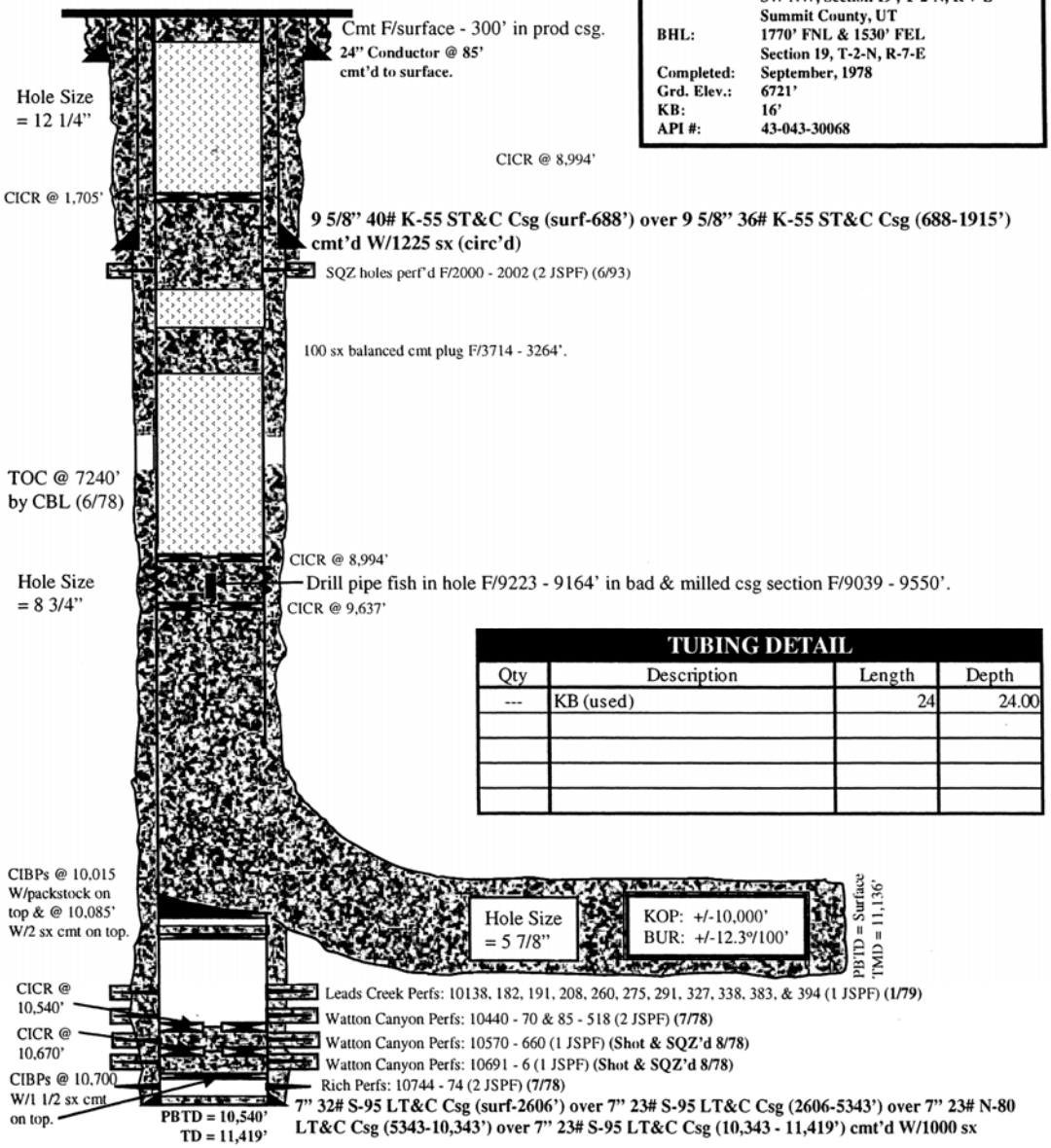
APPENDIX I - WELLBORE DIAGRAMS AND INFORMATION, ELKHORN RIDGE FIELD, SUMMIT COUNTY, UTAH

From: Utah Division Oil, Gas and Mining (2003e).

CITATION OIL AND GAS CORPORATION
WELLBORE DIAGRAM AND INFORMATION

Well Name: UPRR #19-2 **Field:** Elkhorn
Date: December 30, 2002 **Location:** SW NW, Section 19, T-2-N, R-7-E
County: Summit **State:** Utah

Surface:	**1980' FNL & 660' FWL SW NW, Section 19 , T-2-N, R-7-E Summit County, UT**
BHL:	**1770' FNL & 1530' FEL Section 19, T-2-N, R-7-E**
Completed:	**September, 1978**
Grd. Elev.:	**6721'**
KB:	**16'**
API #:	**43-043-30068**



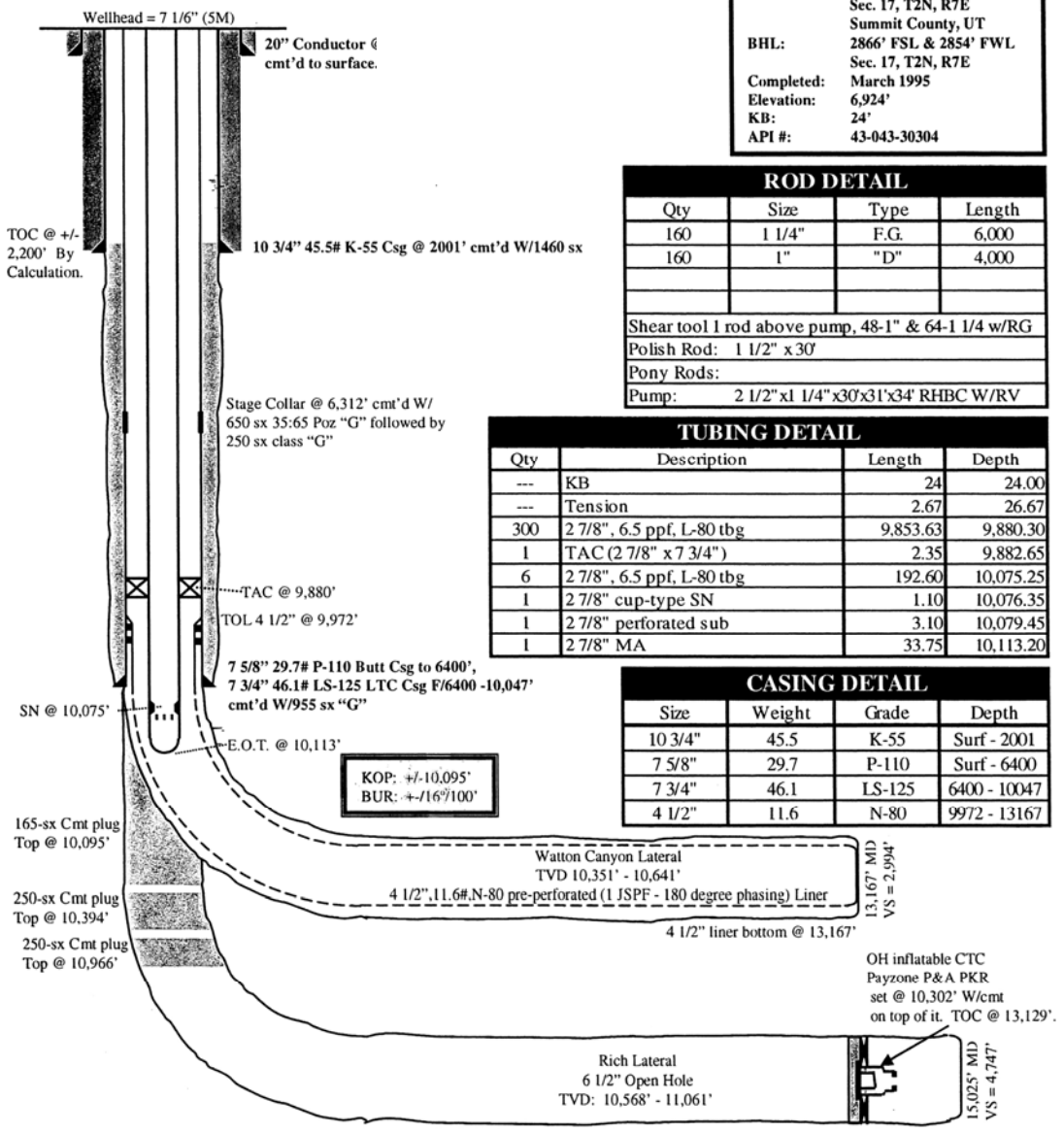
TUBING DETAIL

Qty	Description	Length	Depth
---	KB (used)	24	24.00

CITATION OIL AND GAS CORPORATION
WELLBORE DIAGRAM AND INFORMATION

Well Name: UPRR #17-2H **Field:** UPRC Elkhorn
Date: December 17, 2002 **Location:** SW/SW Sec. 17, T2N, R7E
County: Summit **State:** Utah

Surface:	**825' FSL & 663' FWL Sec. 17, T2N, R7E Summit County, UT**
BHL:	**2866' FSL & 2854' FWL Sec. 17, T2N, R7E**
Completed:	**March 1995**
Elevation:	**6,924'**
KB:	**24'**
API #:	**43-043-30304**



ROD DETAIL

Qty	Size	Type	Length
160	1 1/4"	F.G.	6,000
160	1"	"D"	4,000
Shear tool 1 rod above pump, 48-1" & 64-1 1/4 w/RG			
Polish Rod: 1 1/2" x 30'			
Pony Rods:			
Pump: 2 1/2"x1 1/4"x30'x31'x34' RHBC W/RV			

TUBING DETAIL

Qty	Description	Length	Depth
---	KB	24	24.00
---	Tension	2.67	26.67
300	2 7/8", 6.5 ppf, L-80 tbg	9,853.63	9,880.30
1	TAC (2 7/8" x 7 3/4")	2.35	9,882.65
6	2 7/8", 6.5 ppf, L-80 tbg	192.60	10,075.25
1	2 7/8" cup-type SN	1.10	10,076.35
1	2 7/8" perforated sub	3.10	10,079.45
1	2 7/8" MA	33.75	10,113.20

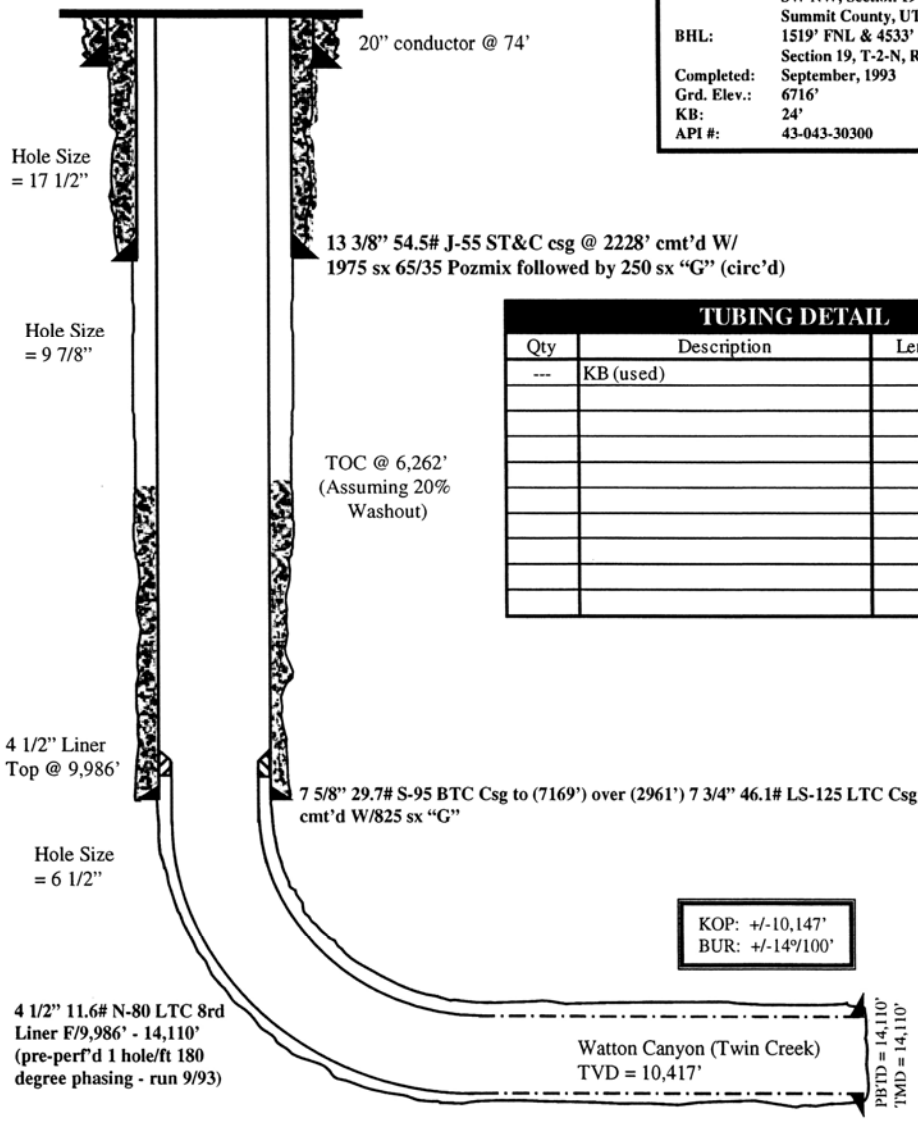
CASING DETAIL

Size	Weight	Grade	Depth
10 3/4"	45.5	K-55	Surf - 2001
7 5/8"	29.7	P-110	Surf - 6400
7 3/4"	46.1	LS-125	6400 - 10047
4 1/2"	11.6	N-80	9972 - 13167

CITATION OIL AND GAS CORPORATION
WELLBORE DIAGRAM AND INFORMATION

Well Name: UPRC #19-2X 1H
Date: December 30, 2002
County: Summit
Field: Elkhorn
Location: SW NW, Section 19, T-2-N, R-7-E
State: Utah

Surface:	**2176' FNL & 554' FWL SW NW, Section 19 , T-2-N, R-7-E Summit County, UT**
BHL:	**1519' FNL & 4533' FWL Section 19, T-2-N, R-7-E**
Completed:	**September, 1993**
Grd. Elev.:	**6716'**
KB:	**24'**
API #:	**43-043-30300**

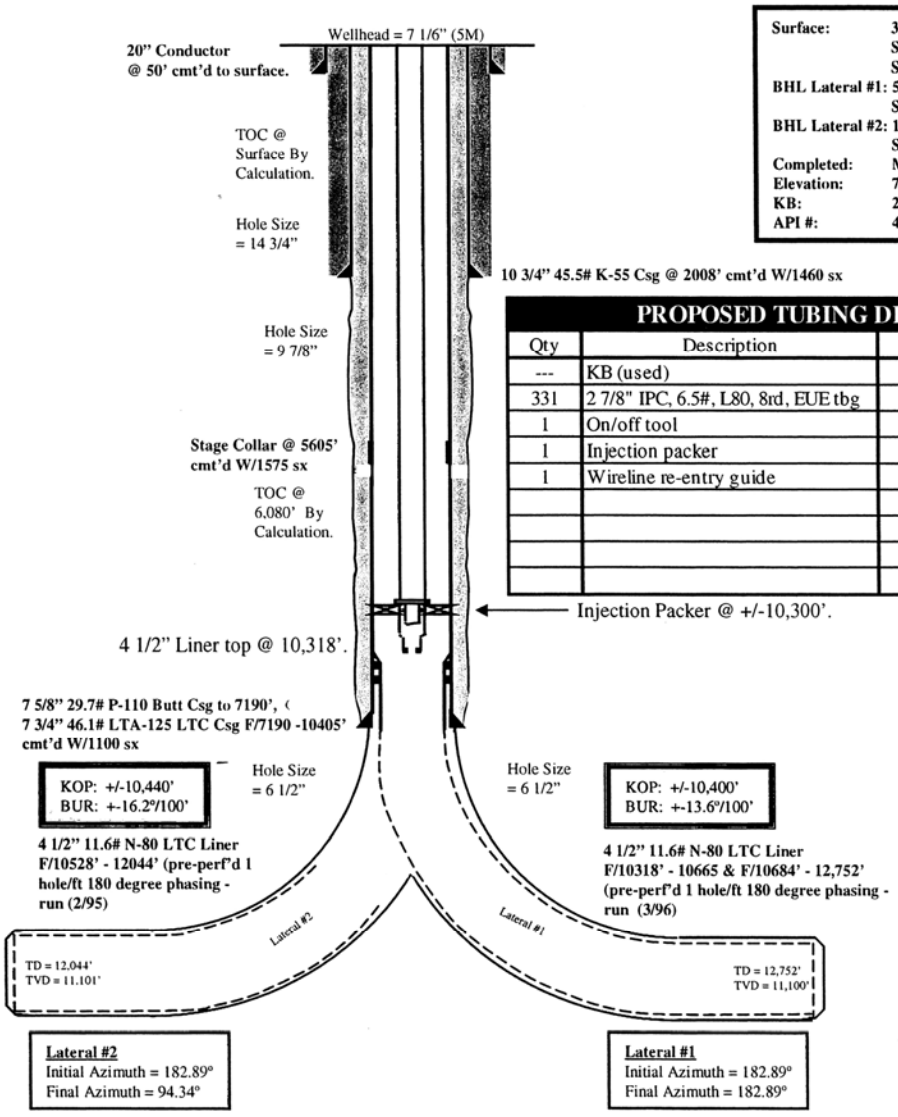


TUBING DETAIL

Qty	Description	Length	Depth
---	KB (used)	24	24.00

CITATION OIL AND GAS CORPORATION
PROPOSED INJECTION WELLBORE DIAGRAM
AND INFORMATION

Well Name: Newton Sheep #20-1H **Field:** Elkhorn
Date: May 1, 2003 **Location:** NW NW, Sec. 20, T-2-N, R-7-E
County: Summit **State:** Utah



Surface:	**370' FNL & 856' FWL Sec. 20, T-2-N, R-7-E Summit County, UT**
BHL Lateral #1:	**570' FNL & 3158' FWL Sec. 20, T-2-N, R-7-E**
BHL Lateral #2:	**1945' FNL & 680' FWL Sec. 20, T-2-N, R-7-E**
Completed:	**March, 1995**
Elevation:	**7,035'**
KB:	**24'**
API #:	**43-043-30310**

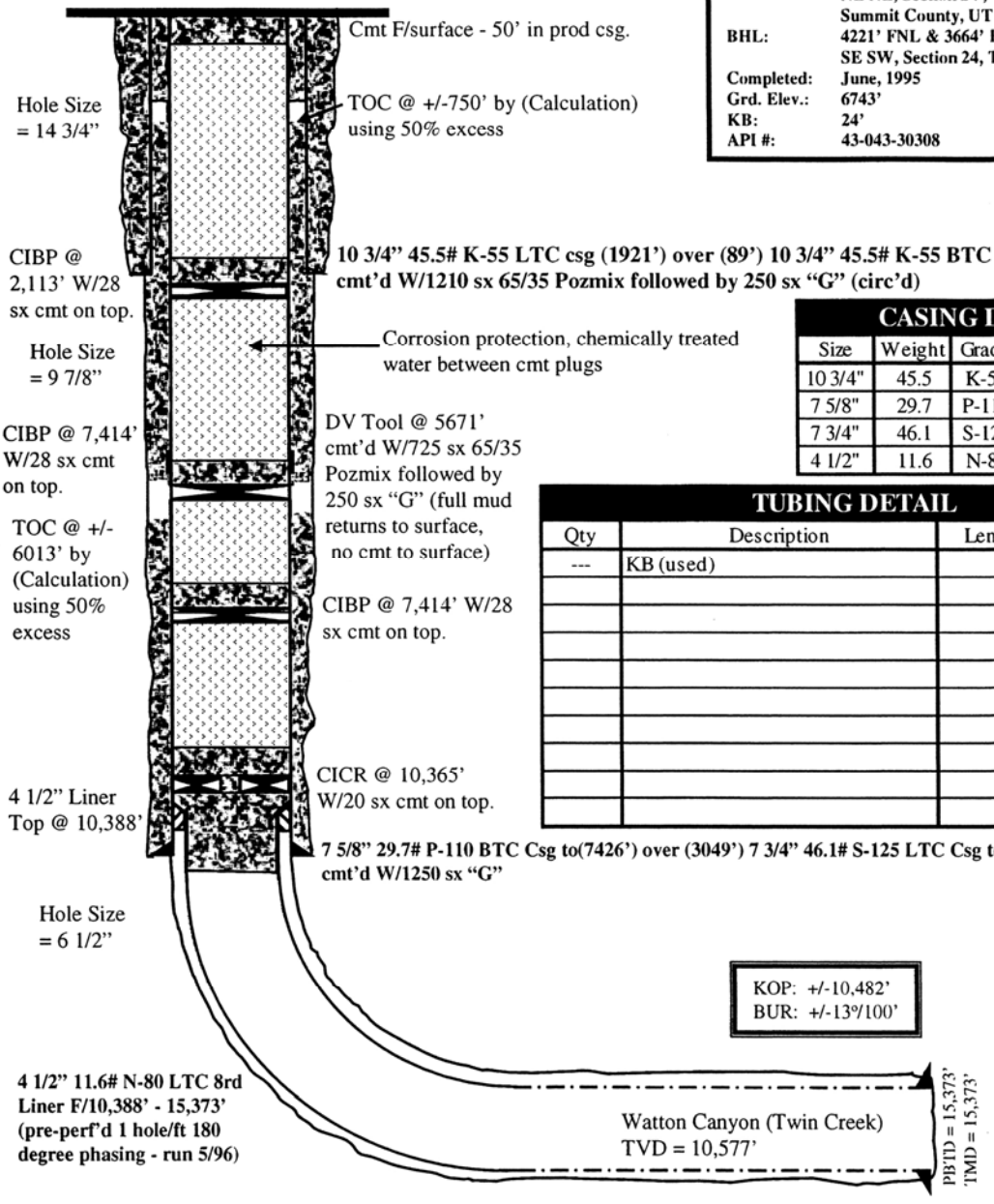
PROPOSED TUBING DETAIL

Qty	Description	Length	Depth
---	KB (used)	23.5	23.50
331	2 7/8" IPC, 6.5#, L80, 8rd, EUE tbg	10,266.50	10,290.00
1	On/off tool	3.00	10,293.00
1	Injection packer	7.00	10,300.00
1	Wireline re-entry guide	1.00	10,301.00

CITATION OIL AND GAS CORPORATION
WELLBORE DIAGRAM AND INFORMATION

Well Name: Newton Sheep Federal #24-1H
Date: December 16, 2002
County: Summit
Field: Elkhorn
Location: NE NE, Section 24, T-2-N, R-6-E
State: Utah

Surface:	**499' FNL & 860' FEL NE NE, Section 24 , T-2-N, R-6-E Summit County, UT**
BHL:	**4221' FNL & 3664' FEL SE SW, Section 24, T-2-N, R-6-E**
Completed:	**June, 1995**
Grd. Elev.:	**6743'**
KB:	**24'**
API #:	**43-043-30308**



CASING DETAIL

Size	Weight	Grade	Depth
10 3/4"	45.5	K-55	Surf - 2010
7 5/8"	29.7	P-110	Surf - 7426
7 3/4"	46.1	S-125	7426 - 10,475
4 1/2"	11.6	N-80	10,388 - 15373

TUBING DETAIL

Qty	Description	Length	Depth
---	KB (used)	24	24.00

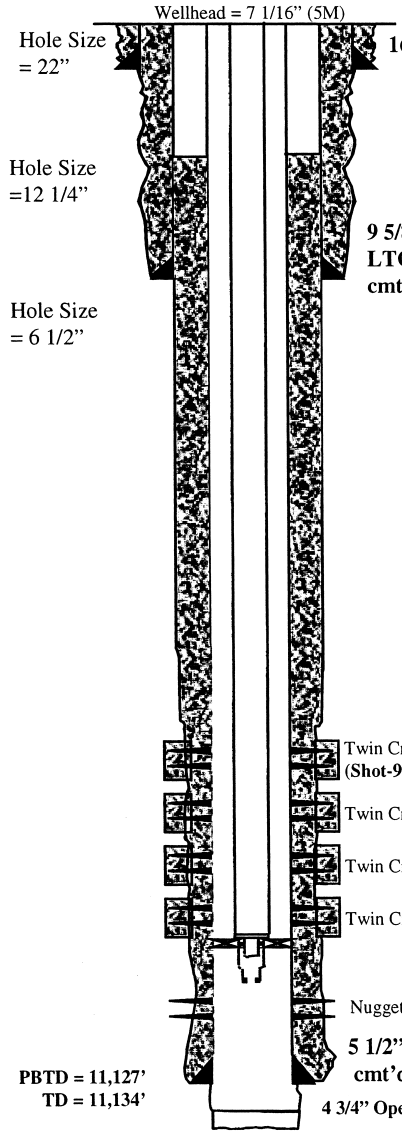
Citation Oil & Gas Corporation
Elkhorn Field, UPRC #17-1 SWD
Wellbore Diagram

Ground Elevation = 6756'
RKB = 6776'
KB = 20'

Present Status

Surface Location

2335' FNL & 2052' FWL,
SE NW, Sec. 17, T-2-N,
R-7-E, Summit County, UT



16" @ 120' cmt'd W/? sx

TOC @ 800' calc.

9 5/8" 40# N-80 LTC Csg @ 1545' cmt'd W/835 sx

TUBING DETAIL			
Qty	Description	Length	Depth
---	KB (used)	20	20.00
1	2 7/8" 6.5# N-80 Duoline	31.39	51.39
1	2 7/8" pup jt	8.15	59.54
346	2 7/8" 6.5# N-80 Duoline	10,853.00	10,912.54
1	Model R-3 DG PKR	7.25	10,919.79
1	WLEG	1.23	10,921.02

Twin Creek Perfs: 10,398 - 428, 38 - 96, 514 - 26, & 36 - 41 (4 JSPF) **(Shot-9 & 10/88) (SQZ'd-12/93)**

Twin Creek Perfs: 10,574 - 602 (2 JSPF) **(Shot-8/88) (SQZ'd-9/88)**

Twin Creek Perfs: 10,692 - 720 (2 JSPF) **(Shot-8/88) (SQZ'd-12/93)**

Twin Creek Perfs: 10,826 - 64 & 72 - 903 (2 JSPF) **(Shot-7/88) (SQZ'd-12/93)**

Nugget Perfs: 10,950 - 11,100 (4 JSPF) **(12/93)**

5 1/2" 17,20 &23# Csg to 9936' & 5 1/2" 20# csg F/9936 - 11,112' cmt'd W/2,900 sx Class H

4 3/4" Open Hole section F/11,112 - 11,134 W/7' of sand in bottom of section.

PBTD = 11,127'
TD = 11,134'

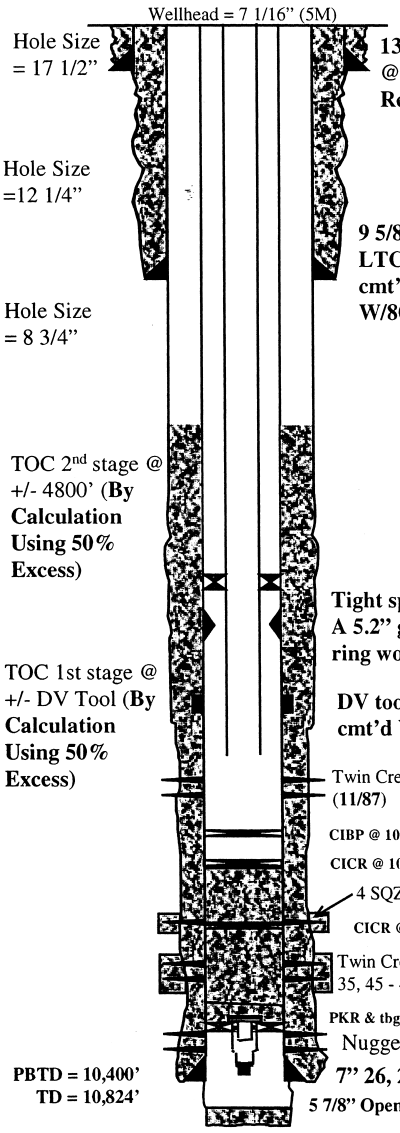
Citation Oil & Gas Corporation
Elkhorn Field, Newton Sheep #18-1
Wellbore Diagram

Ground Elevation = 6530'
RKB = 6552'
KB = 22'

Present Status

Surface Location

1239' FSL & 2390' FEL,
SW SE, Sec. 18, T-2-N,
R-7-E, Summit County, UT



13 3/8" Line pipe @ 85' cmt'd W/ Redimix to surface

9 5/8" 40# N-80 LTC Csg @ 1454' cmt'd to surf W/800 sx

TUBING DETAIL

Qty	Description	Length	Depth
---	KB (used)	22	22.00
283	2 7/8" 6.5# N-80 8rd EUE	8,915.00	8,937.00
1	2 7/8" X 7" TAC	3.00	8,940.00
44	2 7/8" 6.5# N-80 8rd EUE	1,386.00	10,326.00
1	2 7/8" SN	1.00	10,327.00
1	2 7/8" 6.5# N-80 8rd EUE	31.00	10,358.00

ROD & PUMP DETAIL

Qty	Description	Length	Depth
			0.00

PRODUCTION CASING DETAIL

Size	Weight	Grade	Depth
7"	29#	N-80	Surf - 1000'
7"	26#	L-80	1000 - 4400'
7"	26#	K-55	4400 - 5744'
7"	26#	L-80	5744 - 7944'
7"	35#	N-80	7944 - 10774'

Tight spot in casing @ 9,218'. Bad csg noted F/9,130 - 9,250'. A 5.2" gauge ring would go through bad spot, but a 5.45" gauge ring would not. (5/97)

DV tool @ 9511' cmt'd W/840 sx

Twin Creek Perfs: 10,208 - 16, 30 - 75, 77 - 92, 303 - 11, & 31 - 40 (4 JSPF) **(11/87)**

CIBP @ 10,400' (4/88)

CICR @ 10,410' (12/87)

4 SQZ holes @ 10420'. **(12/87)**

CICR @ 10,420' (11/87)

Twin Creek Perfs: 10,431 - 36, 40 - 42, 48 - 52, 80 - 83, 88 - 91, 502 - 14, 18 - 35, 45 - 47, & 53 - 61 (1 JSPF) **(Shot & SQZ'd 11/87)**

PKR & tbg stub left in hole as fish. Fish is from 10,652 - 10,770+' covered W/cmt up to 10,610'. (11/87)

Nugget Perfs: 10,766 - 72 (1 JSPF) **(10/87)**

7" 26, 29, & 35# Csg @ 10774' cmt'd W/254 sx

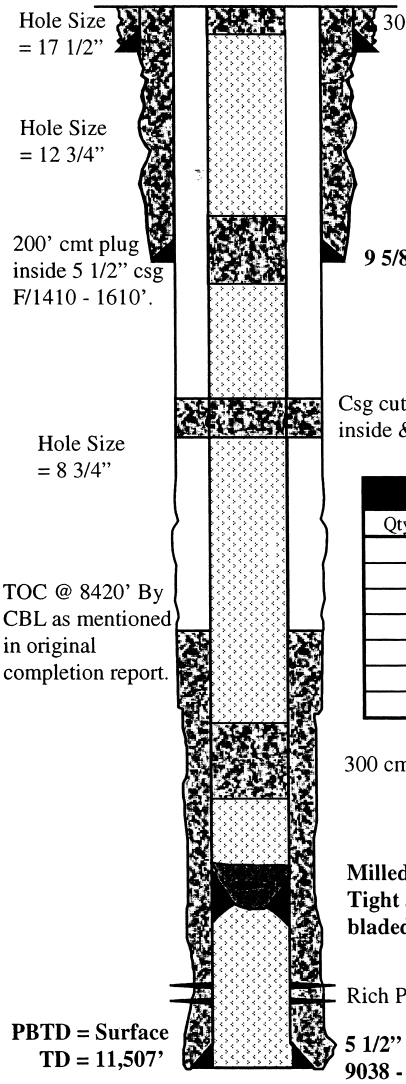
5 7/8" Open Hole section F/10,774 - 10,824 W/Barite plug F/10,802 - 24'.

Citation Oil & Gas Corporation
Elkhorn Field, UPRR #19-1
Wellbore Diagram

Ground Elevation = 7100'
RKB = 7120'
KB = 20'

Present Status

Surface Location
1949' FNL & 1828' FEL,
SW NE, Sec. 19, T-2-N,
R-7-E, Summit County, UT



Hole Size = 17 1/2"

30 sx cmt surface plug inside 5 1/2" csg.

Hole Size = 12 3/4"

200' cmt plug inside 5 1/2" csg F/1410 - 1610'.

9 5/8" 36# K-55 Csg @ 1510' cmt'd W/1210 sx

Csg cut @ 6057'. 200' cmt plug inside & outside of 5 1/2" csg F/6157 - 5957'.

Hole Size = 8 3/4"

TOC @ 8420' By CBL as mentioned in original completion report.

TUBING DETAIL			
Qty	Description	Length	Depth
			0.00

300 cmt plug inside 5 1/2" csg F/9314 - 9014'.

Milled out tight spots & collapses in csg F/9360 - 72'.
Tight spots & possibly collapsed csg F/9678 - 9727'. Top of 3 3/4" bladed mill fish @ 9727' covered W/fill.

Rich Perfs: 11,000 - 30 (2 JSPF) **(9/77)**

PBTD = Surface
TD = 11,507'

5 1/2" 17# N-80 Csg F/surface to 9038' over 5 1/2" 17# S-95 Csg F/ 9038 - 11,507' cmt'd W/1200 sx

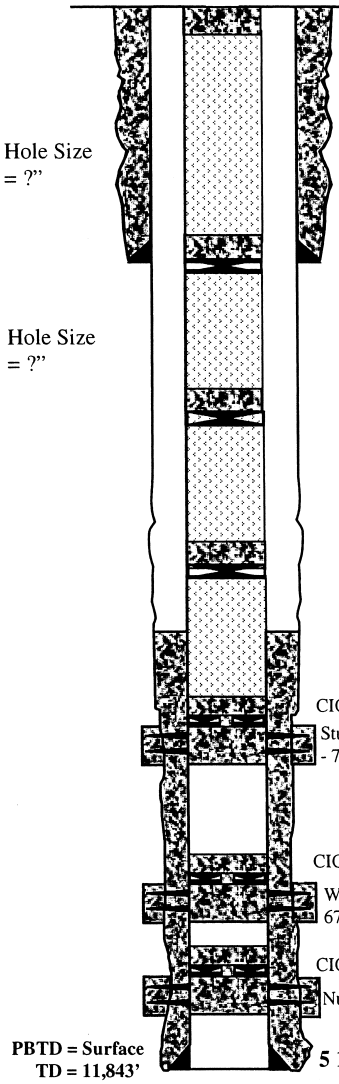
Citation Oil & Gas Corporation
Elkhorn Field, Newton Sheep #24-34
Wellbore Diagram

Ground Elevation = 6705'
RKB = ?'
KB = ?'

Present Status

Surface Location

794' FSL & 1555' FEL,
SW SE, Sec. 24, T-2-N,
R-6-E, Summit County, UT



TUBING DETAIL			
Qty	Description	Length	Depth
			0.00

National Energy Technology Laboratory

626 Cochrans Mill Road
P.O. Box 10940
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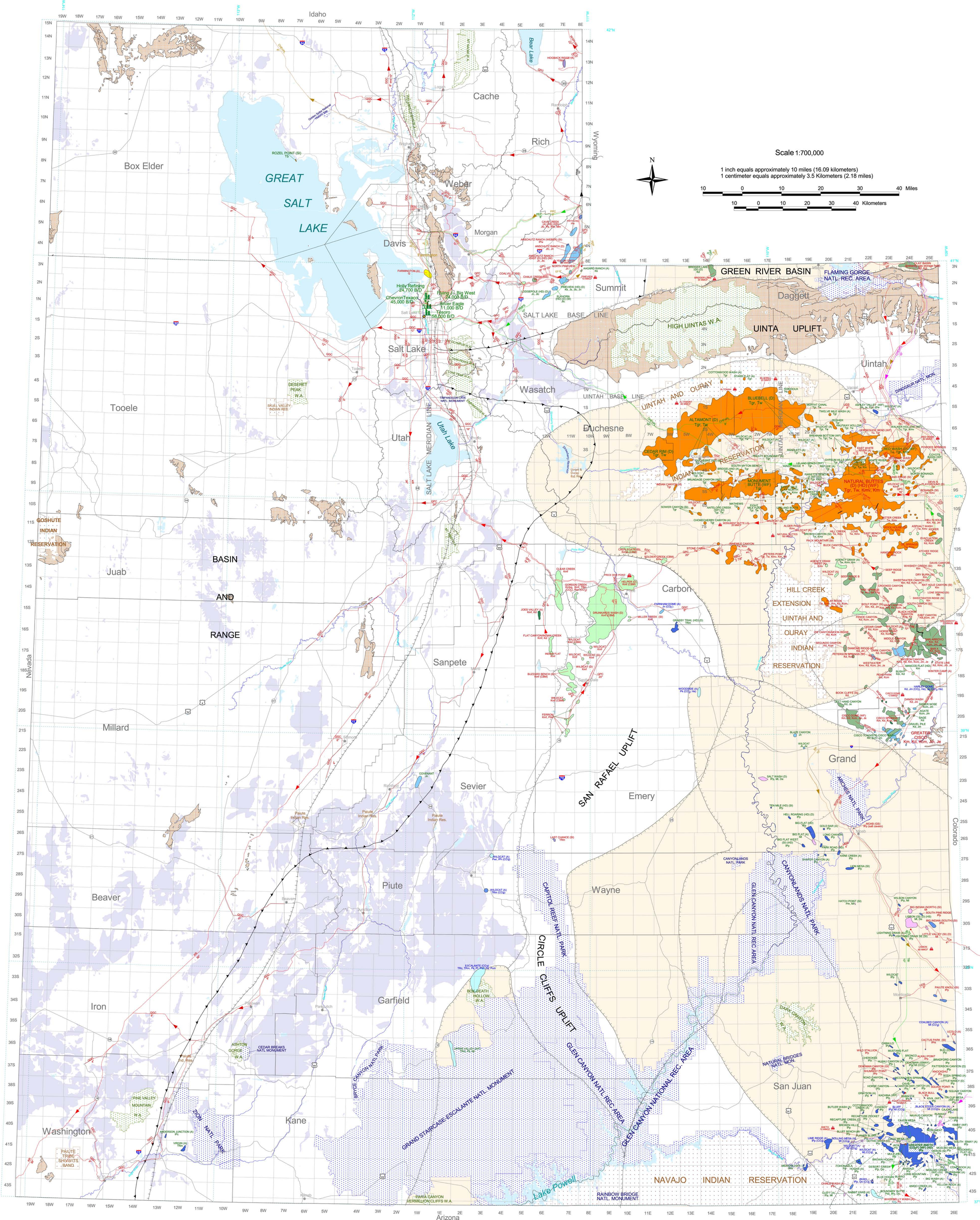
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EXPLANATION

RESERVOIR ROCKS

- Quaternary (Q)
- Tertiary (T)
- Upper Cretaceous (K)
- Upper-Lower Cretaceous (K)
- Jurassic (J)
- Triassic (TR)
- Permian (P)
- Pennsylvanian (IPp)
- Mississippian (M)
- Devonian (D)

SURFICIAL GEOLOGIC FEATURES

- Leading edge of Sevier thrust belt
- Basin and uplift boundary (hash marks toward basin and away from uplift)
- Major sedimentary basin
- Undifferentiated Precambrian rocks exposed on the surface
- Tertiary/Quaternary volcanic rocks

QUATERNARY
Q Undivided sediments

TERTIARY
Tb Basalt
Tu Uinta Formation
Tgr Green River Formation
Tw Wasatch Formation

UPPER CRETACEOUS
Kmv Mesaverde Group
Kcg Castlegate Sandstone
Kmvb Mesaverde Group, Blackhawk Formation
Km Mancos Shale
Kmbg Mancos Shale, Blue Gate Shale Member
Kmf Mancos Shale, Ferron Sandstone Member
Kf Frontier Formation

UPPER-LOWER CRETACEOUS
Kd Dakota Sandstone
Kcm Cedar Mountain Formation
Kk Kelvin Formation

JURASSIC
Jm Morrison Formation
Js Stump Formation
Jc Curtis Formation
Je Entrada Sandstone
Jtc Twin Creek Limestone
Jn Nugget/Navajo Sandstone
Jk Kayenta Formation
Jw Wingate Sandstone

TRIASSIC
TRc Chinle Formation
TRm Moenkopi Formation
TRd Dinwoody Formation

PERMIAN
Pp Phosphoria Formation
Ppc Park City Formation
Pk Kaibab Limestone
Pbb Black Box Dolomite
Pwr White Rim Sandstone
Po Organ Rock Formation
Pcm Cedar Mesa Sandstone
Pdc DeChelly Sandstone
Pt Toroweap Formation

PENNSYLVANIAN
IPw Weber Sandstone
IPh Hermosa Formation
IPht Honaker Trail Formation
IPp Paradox Formation
IPm Molas Formation
IPc Callville Limestone

MISSISSIPPIAN
Ml Leadville Limestone
Mm Madison Group
Mr Redwall Limestone

DEVONIAN
De Elbert Formation
Do Ouray Formation

REFINERIES AND PLANTS

Tesoro 58,000 B/D — Oil refinery. Notation includes operator and capacity in barrels of oil per day (B/D). Locations are approximate.

Red Wash 50 MMCF — Natural gas processing plant. Notation includes operator and capacity (where data are available) in millions of cubic feet (MMCF) per day. Locations are approximate.

PIPELINES

Notation includes operator (see Pipeline Operators below), pipe diameter in inches, and direction of flow. Adjacent diameter numbers indicate more than one pipeline of the same type. Pipeline routes are plotted as accurately as possible and are only accurate within the scale of this map. Most infield gathering and utility distribution systems are not shown.

- PPC 8 — Crude oil
- QPC 16,26 — Natural gas
- CHEVPL 12 — Carbon dioxide
- ARME 10 — Hydrogen sulfide-bearing gas
- PPC 8 — Natural gas processing plant or refinery products

PIPELINE OPERATORS

ARME – Anadarko Rocky Mountain Energy
BBC – Bill Barrett Corp.
CHEVPL – Chevron Pipeline Company
CIG – Colorado Interstate Gas Company
CPC – ConocoPhillips Co.
EOC – Evergreen Operating Corp.
EP – Enterprise Products Partners LP
EM – ExxonMobil
FCPC – Four Corners Pipeline Company
IR – Inland Resources, Inc.
KR – Kern River Gas Transmission Company
MESA – MESA, Inc.
NNOG – Navajo Nation Oil and Gas
PEP – Pacific Energy Partners LP
PPC – Pioneer Pipeline Company
QGC – Questar Gas Company
QPC – Questar Pipeline Company
RMPS – Rocky Mountain Pipeline Systems LLC
TBI – Tom Brown, Inc.
TCP – TransColorado Pipeline Gathering Company
UGS – Utah Gas Services Company
UTNJNR – Ute Tribe/New Jersey Natural Resources
WGPLNW – Williams Gas Pipeline – Northwest
WGR – Western Gas Resources, Inc.

FIELDS

Fields are spotted through January 2005. Field boundaries are approximate and do not distinguish between different producing horizons. Dry holes may exist within fields. Field color indicates predominant age of reservoir rocks. Both abandoned and currently producing formations are shown for each field.

ROCK HOUSE (W, KmvPp) — Names in red denote fields that primarily produce(d) natural gas. These fields may produce significant condensate along with the natural gas in the primary reservoir or oil from secondary reservoirs

LISBON (M, Ds) — Names in green denote fields that primarily produce(d) oil. These fields may produce significant associated natural gas along with the oil in the primary reservoir or nonassociated natural gas from secondary reservoirs.

FARNHAM DOME (A) Jn (CO_2) — Names in blue denote fields that primarily produce(d) carbon dioxide. These fields may produce significant natural gas (methane) and oil in the primary and secondary reservoirs.

FIELD DESIGNATIONS

(A) – Abandoned field
(CBM) – Coalbed methane
(CO_2) – Carbon dioxide reservoir
(CO_2F) – CO_2 flood project
(D) – Produced water disposal project
(GI) – Gas injection
(GS) – Gas storage
(He) – Helium reservoir
(HD) – Horizontal drilling project
(HS) – Hydrogen sulfide
(NI) – Nitrogen injection
(SI) – Shut-in field
(WF) – Waterflood project

Note: These designations appear after field name, reservoir name, or reservoir.

OTHER SYMBOLS AND DESIGNATIONS

- State Capitol
- County Seat
- Road
- Longitude/Latitude
- Township/Range
- Lake, reservoir & intermittent water
- Major river
- National Park, Monument, Recreation Area
- Indian Reservation
- Wilderness Area

BASE MAP COVERAGES AND SOURCE DATA

County boundaries, city locations, federal boundaries, Public Land Survey System (PLSS), highways and roads, landownership from Utah Automated Geographic Reference Center

COORDINATE SYSTEM:
Transverse Mercator
False Easting: 500000.000000
False Northing: 0.000000
Central Meridian: -111.000000
Scale Factor: 0.999600
Latitude Of Origin: 0.000000
Geographic Coordinate Systems North American 1983
Datum: D North American 1983
Prime Meridian: 0

UTAH DNR GEOLOGICAL SURVEY
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Plate 1. Oil and gas fields map of Utah.

After Chidsey and others, 2004, Utah Geological Survey Map 203DM (updated in 2005).

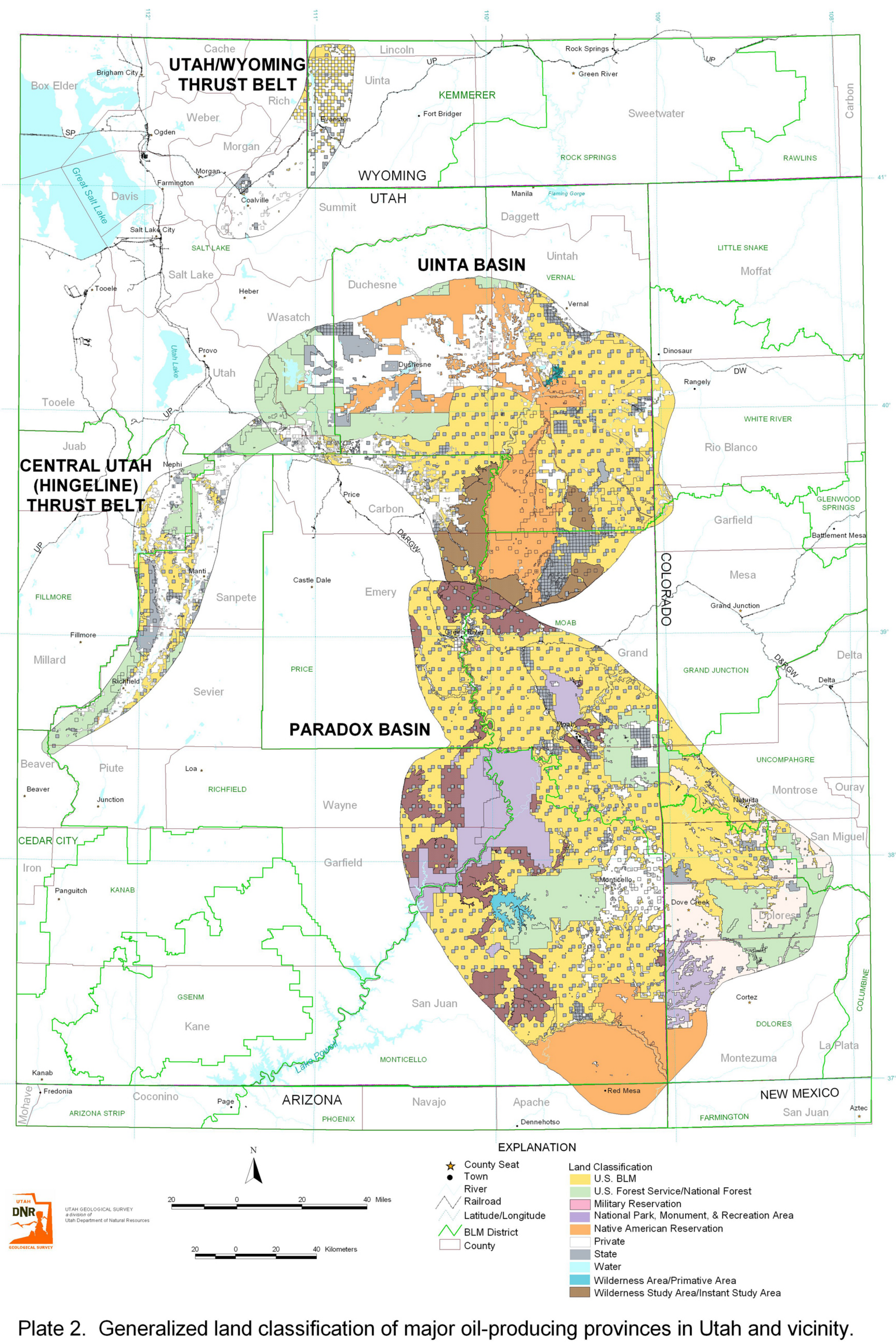


Plate 2. Generalized land classification of major oil-producing provinces in Utah and vicinity.

10 0 10 Miles

10 0 10 Kilometers

Explanation

- U.S. BLM District
- County
- Township/Range
- County Seat
- Road
- River
- Gas Field
- Oil Field

Land Classification

- U.S. BLM
- Private
- State
- Water

T19N R120W
T19N R119W
T19N R118W
Lincoln
T18N R118W
KEMMERER
T9N R8E
T17N R118W
T8N R8E
Uinta
Bear River
T16N R119W
T7N R7E
Rich
Utah
Wyoming
T15N R119W
T6N R7E
Evanston
T6N R6E
T14N R119W
T5N R6E
Morgan
T4N R5E
T13N R120W
SALT LAKE
T12N R121W
T3N R4E
Summit
T3N R8E
Coalville
T2N R3E
T2N R7E
Morgan
Weber River
T1N R3E
T1N R6E
Rockport Res
T1N R4E
T1N R5E

N

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Plate 3. Land classification of the Utah/Wyoming thrust belt play area.

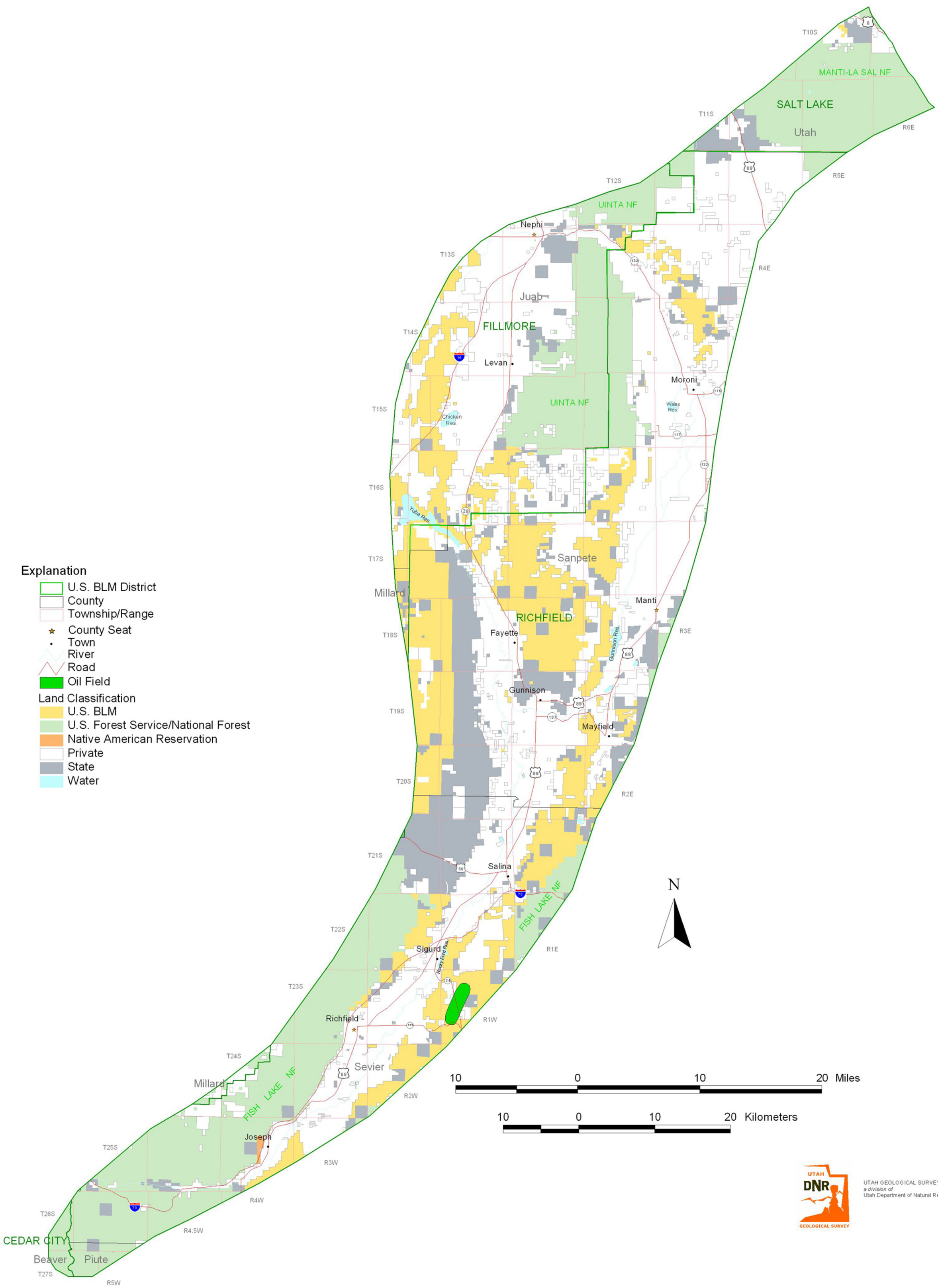


Plate 4. Land classification of the central Utah thrust belt - Hingeline play area.

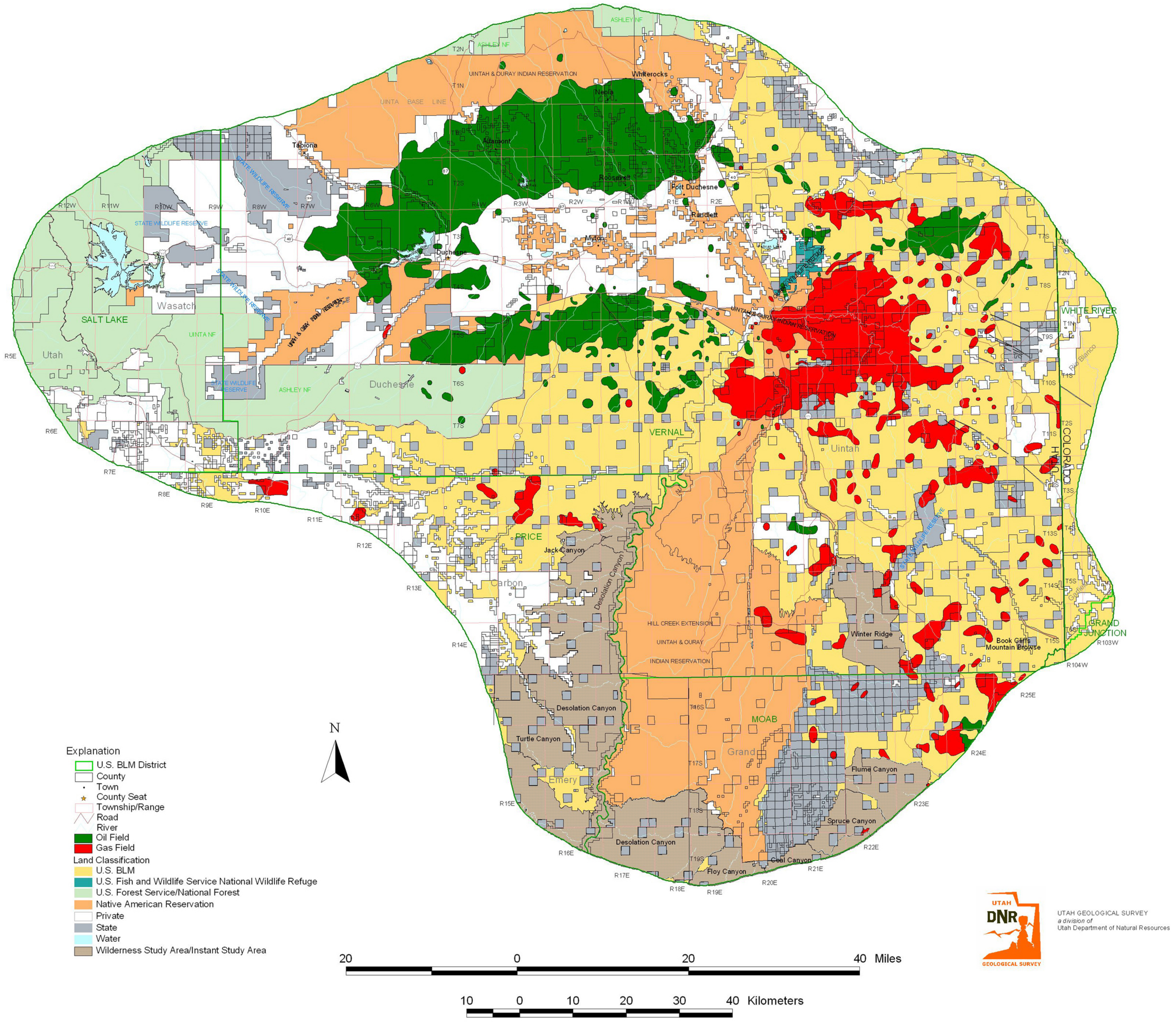


Plate 5. Land classification of the Uinta Basin play area.

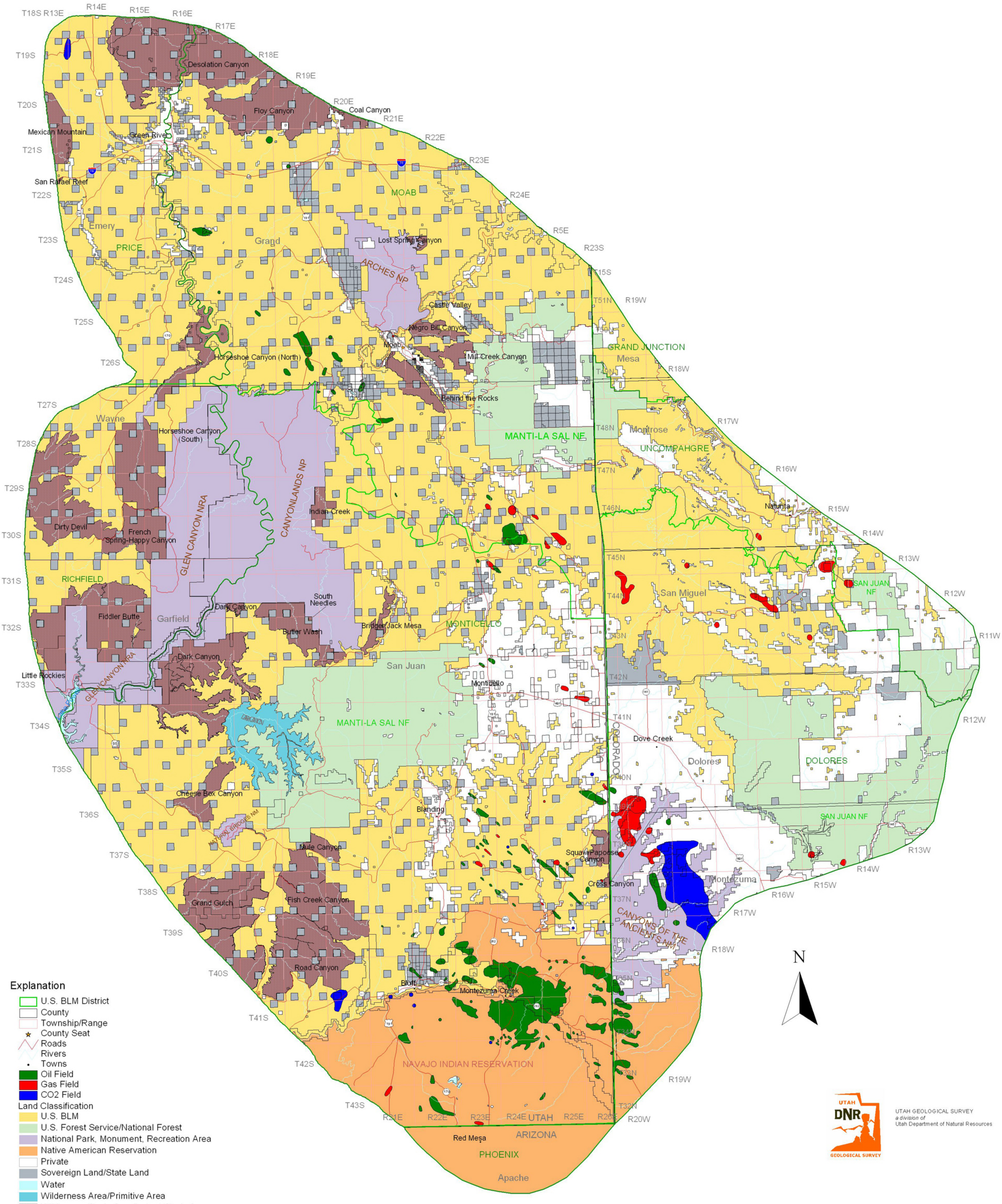


Plate 6. Land classification of the Paradox Basin play area.