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MAJOR OIL PLAYS IN UTAH AND VICINITY

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Office of Fossil Energy

DISCLAIMER

MAJOR OIL PLAYS IN UTAH AND VICINITY

QUARTERLY TECHNICAL PROGRESS REPORT

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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 production increased due, in part, to the discovery of Covenant field in the central Utah Navajo Sandstone thrust belt play. The Utah Geological Survey believes this new upward production trend can continue by 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. 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.

This report covers research activities for the twenty-first quarter of the project (July 1 through September 30, 2007). This work included (1) analyzing best practices used in the Pennsylvanian Paradox Formation play, Utah Paradox Basin, and (2) technology transfer activities. 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. 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. Traps types include stratigraphic, stratigraphic with some structural influence, combination stratigraphic/structural, structural, and diagenetic.

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. 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.

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. 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.

Reservoir three-dimensional (3-D) modeling and simulation should be major components in designing waterflooding and CO_2 flood programs for 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.

Technology transfer activities during this quarter consisted of a non-technical presentation describing the new central Utah thrust belt Navajo Sandstone oil play and a publication. Project team members joined Utah Stake Holders Board Members in attending the Uinta Basin Oil and Gas Collaborative Group meeting in Vernal, Utah. We also prepared the final manuscript on the petroleum geology of Covenant field in the central Utah thrust belt play for inclusion in the Utah Geological Association's 2007 guidebook on the geology of central Utah. The project home page was updated on the Utah Geological Survey Web site.

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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 production increased due to the discovery of Covenant field in the central Utah Navajo Sandstone thrust belt play. 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 is producing 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. This report covers research activities for the twenty-first quarter of the project (July 1 through September 30, 2007). This work included (1) analyzing best practices used in the Pennsylvanian Paradox Formation play, Utah Paradox Basin, and (2) technology transfer activities.

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. 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.

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 Cane Creek, Desert Creek, and Ismay. The Paradox Formation oil play area includes nearly the entire Paradox Basin. Traps in the Blanding sub-basin and Aneth platform regions 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), fracturing, and diagenetic effects.

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.

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. 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 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 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 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.

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, 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 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.

Technology transfer activities during this quarter consisted of a non-technical presentation describing the geology of Covenant field and the central Utah thrust belt Navajo Sandstone oil play to a public planning meeting of the Sanpete County Commission. Project team members joined Utah Stake Holders Board Members in attending the Uinta Basin Oil and Gas Collaborative Group meeting in Vernal, Utah. We also prepared the final manuscript on the petroleum geology of Covenant field in the central Utah thrust belt play for inclusion in the Utah Geological Association's 2007 guidebook on the geology of central Utah. The project home page was updated on the Utah Geological Survey Web site. Project team members published a Quarterly Technical Progress Report detailing project work, results, and recommendations.

INTRODUCTION

Project Overview

Utah oil fields have produced over 1.33 billion barrels (bbls) (211 million m^3) (Utah Division of Oil, Gas and Mining, 2007). 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 production increased (figure 1), due to the discovery of Covenant field in the central Utah Navajo Sandstone thrust belt play, and reversed the decline that began in the mid-1980s (Utah Division of Oil, Gas and Mining, 2006). 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.

Utah's drilling history has fluctuated greatly due to discoveries, oil and gas price trends, and changing exploration targets. 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 record 1110 wells were spudded (Utah Division of Oil, Gas and Mining, 2008a, 2008b). Sustained high petroleum prices are providing the economic climate needed to entice more high-risk exploration investments (more wildcats), resulting in new discoveries.

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

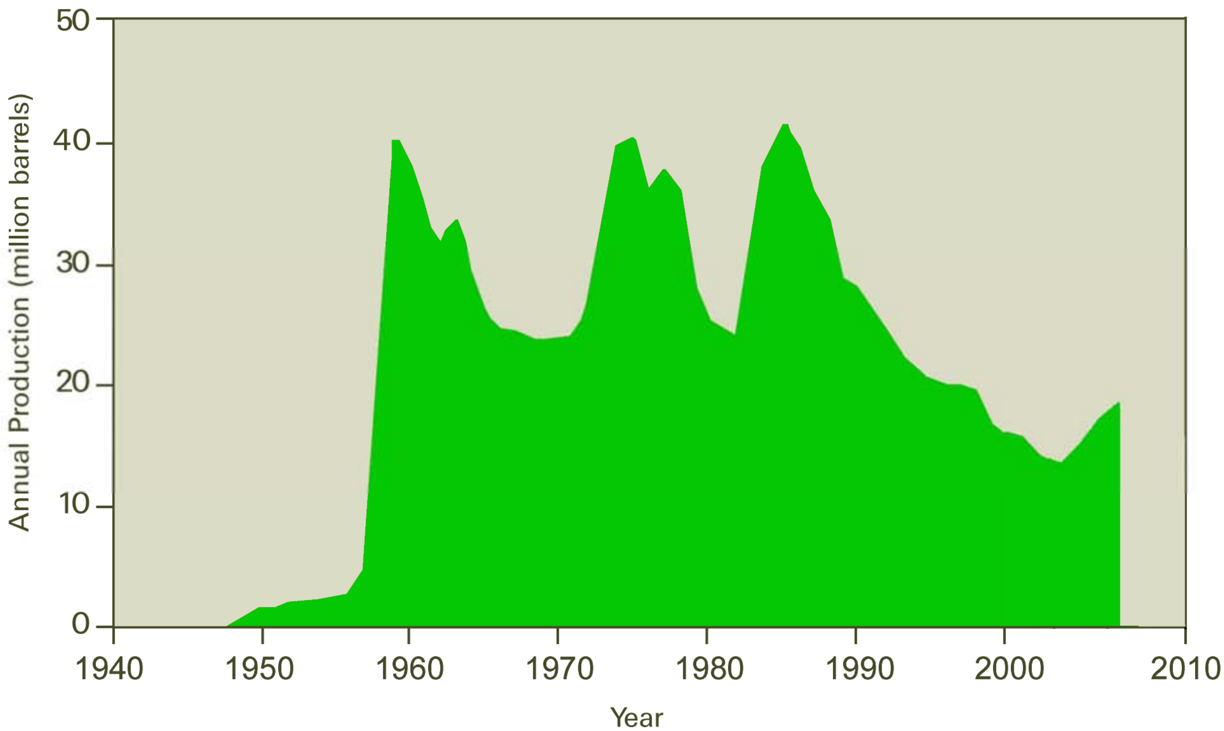


Figure 1. Oil production in Utah as of January 1, 2007 showing an increase due, in part, to the discovery of Covenant field in the new central Utah thrust belt Jurassic Navajo Sandstone play. Data source: Utah Division of Oil, Gas and Mining production records.

surveys. Development of potential prospects is within the economic and technical capabilities of both major and independent operators.

The primary goal of this study is to increase recoverable oil reserves from existing field reservoirs and new discoveries by 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 (figures 2 and 3). These play portfolios will include descriptions (such as stratigraphy, diagenetic analysis, tectonic setting, reservoir characteristics, trap type, seal, and hydrocarbon source) and maps of the major oil plays by reservoir; production and reservoir data; case-study field evaluations; summaries of the state-of-the-art drilling, completion, and secondary/tertiary techniques for each play; locations of major oil pipelines; and descriptions of reservoir outcrop analogs for each play. Also included will be an analysis of land-use constraints on development, such as wilderness or roadless areas, and national parks within oil plays.

This report covers research activities for the twenty-first quarter of the project (July 1 through September 30, 2007). This work included (1) analyzing best practices used in the Pennsylvanian Paradox Formation play of the Paradox Basin, Utah, and (2) technology transfer activities.

Project Benefits

The overall goal of this multi-year project is enhanced petroleum production in the Rocky Mountain region. Specific benefits expected to result from this project 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,

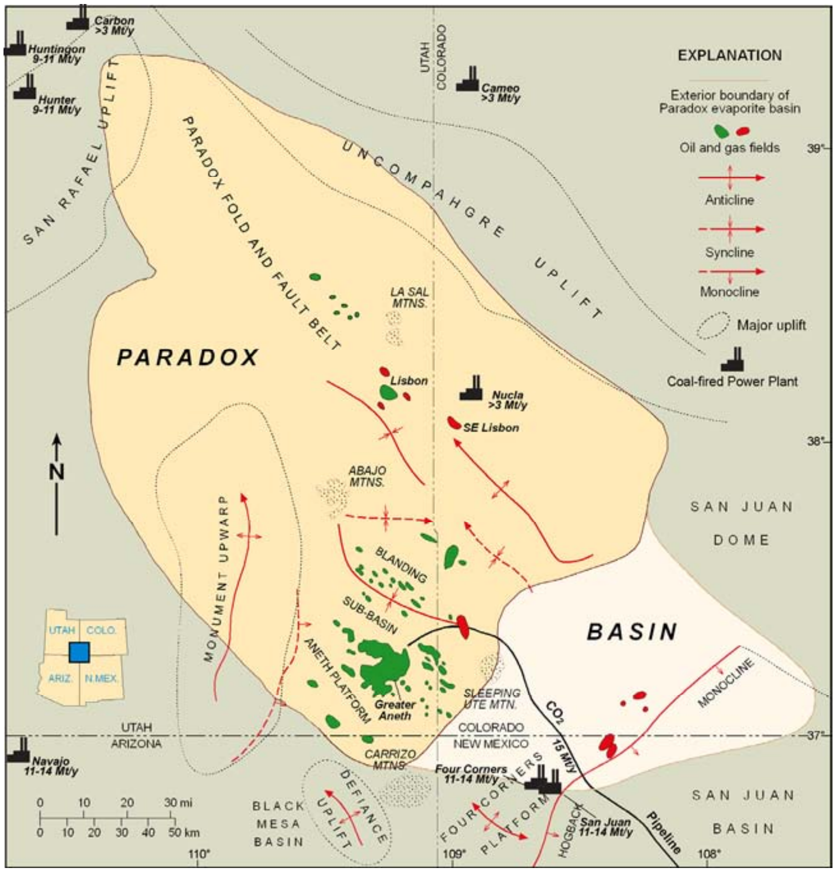
(3) identification of the latest drilling, completion, and secondary/tertiary techniques to increase deliverability,

(4) identification of reservoir trends for field extension drilling and stimulating exploration 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) technology transfer to encourage new development and exploration efforts, and increase royalty income to the federal, state, local, Native American, and fee owners.



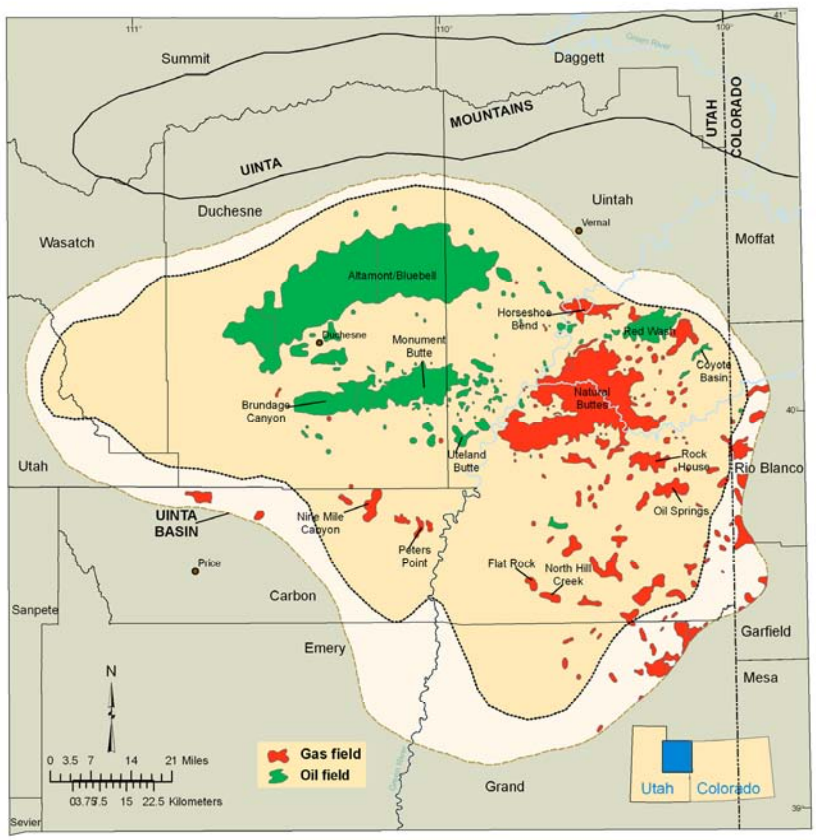
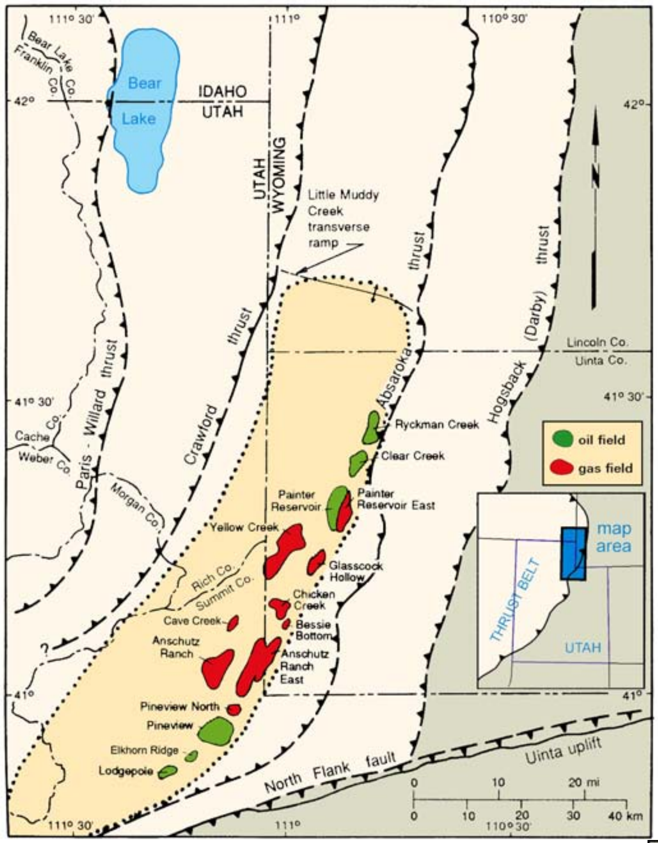


Figure 2. A - Oil and gas fields in the Paradox Basin of Utah, Colorado, and Arizona (modified from Harr, 1996). Also included are the locations of and emissions from surrounding coal-fired power plants; Mt/y = million tons of CO_2 per year. B - Oil and gas fields in the Uinta Basin of Utah (modified from Chidsey and others, 2004b). Colored (light orange) area shows present and potential of plays areas in the Paradox and Uinta Basins.

A



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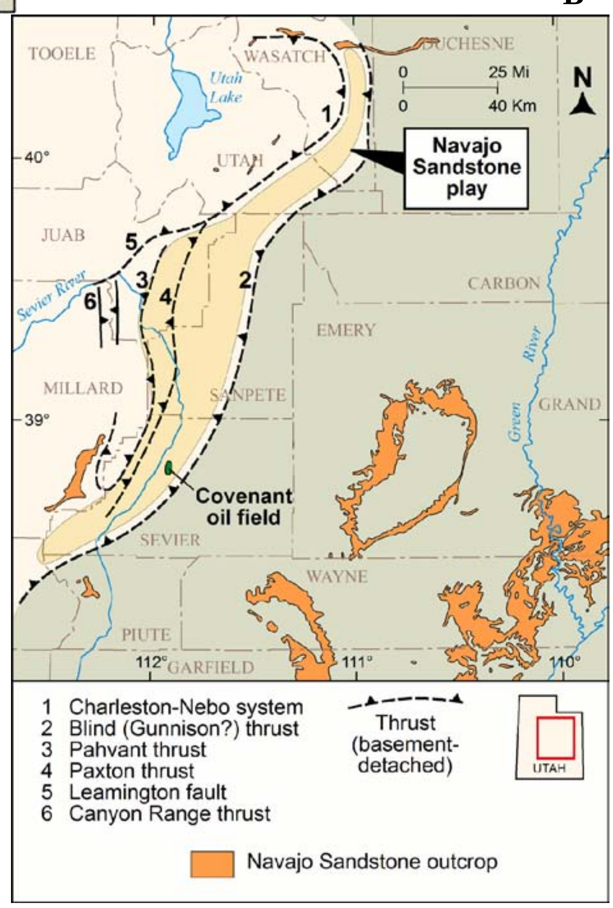

Figure 3. A - Oil and gas fields, uplifts, and major thrust faults in the Utah-Wyoming thrust belt. B - Location of Covenant oil field, uplifts, and selected thrust systems in the central Utah thrust belt province. Numbers and sawteeth are on the hanging wall of the corresponding thrust system. Modified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

The Utah play portfolios produced by this project will provide an easy-to-use geologic, engineering, and geographic reference to help petroleum companies plan exploration, land-acquisition strategies, and field development. These portfolios may also help pipeline companies plan future facilities and pipelines. Other users of the portfolios will include petroleum engineers, petroleum land specialists, landowners, bankers and investors, economists, utility companies, manufacturers, county planners, and numerous government agencies.

The results of this project will be transferred to industry and other interested parties through establishment of Technical Advisory and Stake Holders Boards, an industry outreach program, and technical presentations at national and regional professional society meetings. All of this information will be made public through (1) the Utah Geological Survey (UGS) Web site, (2) an interactive, menu-driven digital product on compact disc, and (3) hard-copy publications in various technical or trade journals and UGS publications.

BEST PRACTICES FOR THE PENNSYLVANIAN PARADOX FORMATION, PARADOX BASIN PLAY – DISCUSSION AND RESULTS

Paradox Formation, Paradox Basin Play Description

The most prolific oil and gas play in the Paradox Basin is the Pennsylvanian Paradox Formation play (figure 4). The Paradox has produced over 500 million bbls 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, 2007; Colorado Oil & Gas Conservation Commission, 2007). Greater Aneth field, Utah's largest oil producer, was discovered in 1956, and it has produced over 446 million BO (71 million m^3) (Utah Division of Oil, Gas and Mining, 2007). The remaining production is from nearly 100 small fields in the basin.

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 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.

Rapid subsidence of the Paradox Basin, particularly during the Pennsylvanian and then 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. Deposition in the basin produced a thick cyclical sequence of carbonates, evaporates, and organic-rich shale in a subtropical arid environment. A shallow-water carbonate shelf on the south and southwest margins of the basin that locally contained carbonate buildups. These carbonate buildups, and the material shed from their flanks, formed petroleum traps where reservoir-quality porosity and permeability have developed.

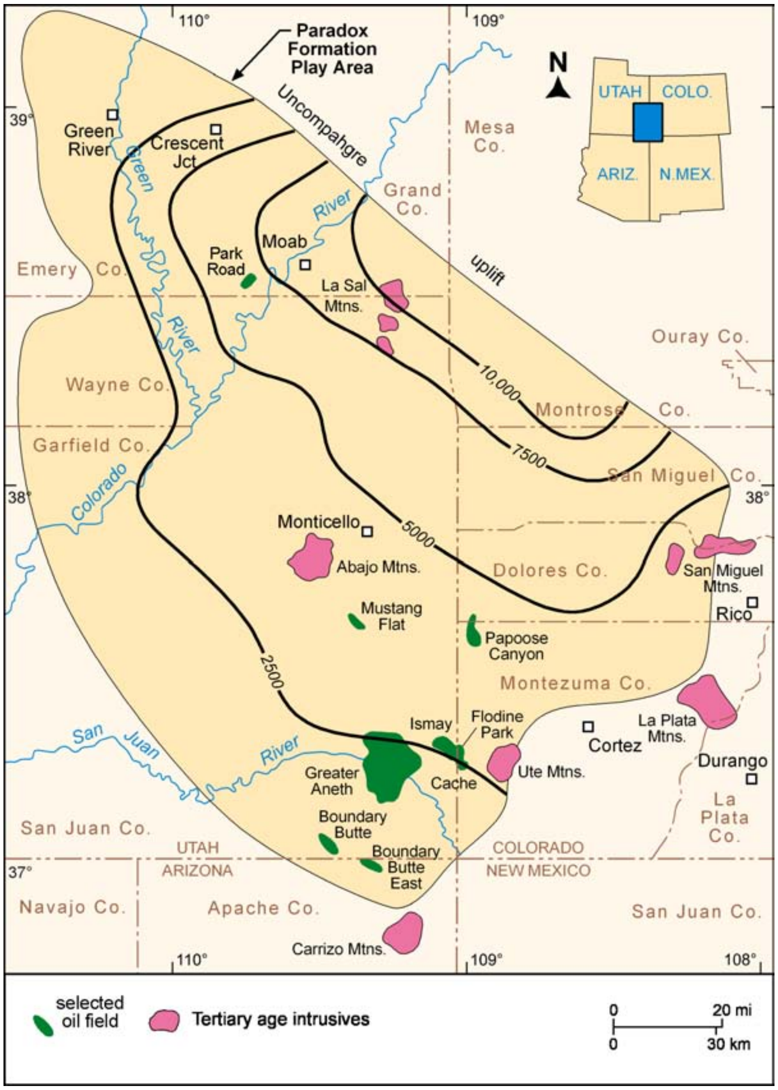

Figure 4. Pennsylvanian Paradox Formation play area, Utah, Colorado, and Arizona. Thickness of the Pennsylvanian rocks shown in feet. Modified from Choquette (1983).

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 southeasternmost Utah (figure 2A). The Paradox fold and fault belt was created during the Tertiary and Quaternary by a combination of (1) reactivation of basement normal faults, (2) salt flowage, dissolution, and collapse, and (3) regional uplift (Doelling, 2000). The relatively undeformed Blanding sub-basin and Aneth platform developed on a shallow-marine shelf. Each area contains oil and gas fields with structural, stratigraphic, or combination traps formed on discrete, often seismically defined, closures. Most Paradox Formation oil production comes from stratigraphic traps in the Blanding sub-basin and Aneth platform that locally contain algal-mound and other carbonate lithofacies buildups.

The three main producing zones of the Paradox Formation are informally named the Cane Creek shale, Desert Creek zone, and Ismay zone (Hite, 1960; Hite and Cater, 1972; and Reid and Berghorn, 1981) (figure 5). 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. 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

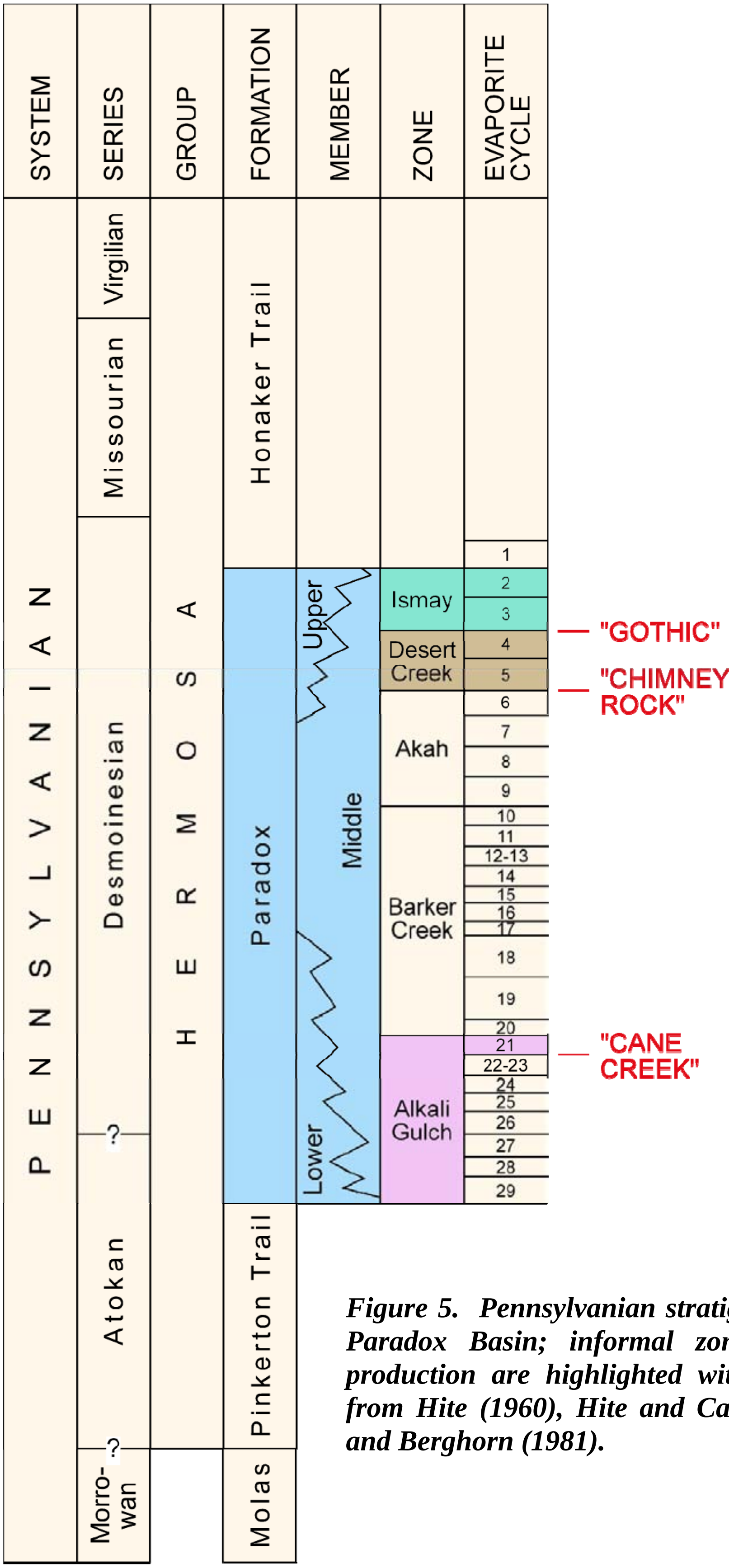

Figure 5. Pennsylvanian stratigraphic chart for the Paradox Basin; informal zones with significant production are highlighted with colors. Modified from Hite (1960), Hite and Cater (1972), and Reid and Berghorn (1981).

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.

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 or fractured reservoirs developed on subtle anticlinal noses or structural closures. 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.

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, such as the Cane Creek, Chimney Rock, 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), fracturing, and diagenetic effects. The extent of these factors, and how they are combined, affect the degree to which fluid flow barriers are created. 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.

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.

The Paradox Formation oil play area includes nearly the entire Paradox Basin (figure 4); the formation produces only gas in the southeastern part of the basin in Colorado. The Paradox Formation Play is divided into four subplays (Chidsey and others, 2004a; Chidsey, 2006) (figure 6): (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.

Data Collection

During the quarter, data were collected from the files of the Utah Division of Oil, Gas and Mining, where there is a wealth of publicly available information, and from various publications for fields in the Utah portion of the Paradox Basin. This information includes structure maps and cross sections, production and pressure data, completion and injection reports, drilling and development plans, and testimony given at spacing hearings and other hearings before the Utah Division of Oil, Gas and Mining. The purpose of this data collection was to help determine the best drilling, completion, and secondary/tertiary recovery techniques for these and similar fields in the Paradox Basin.

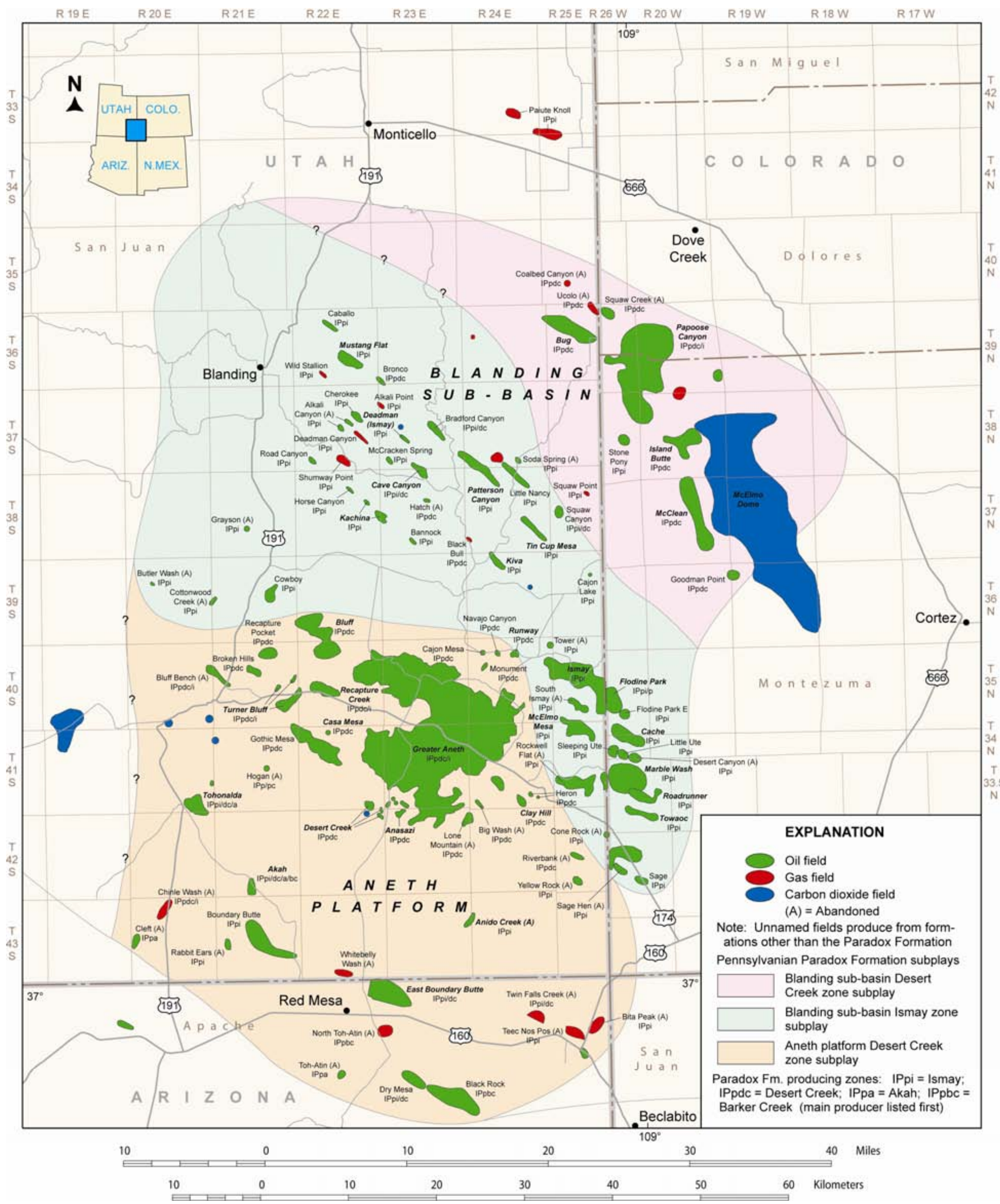

Figure 6. Location of the Paradox Formation Blanding sub-basin Desert Creek zone, Blanding sub-basin Ismay zone, and Aneth platform Desert Creek zone subplays, southeastern Utah, southwestern Colorado, and northeastern Arizona. The fractured shale subplay includes the entire Paradox Basin as shown on figure 4. Fields in italics have produced over 500,000 BO as of September 30, 2007. Modified from Chidsey and others (2004b); Wray and others (2002).

Drilling and Completion Operations

Drilling in the Paradox Basin 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 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, 1978; 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 5); 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 5) to total depth to determine total gas and sample breakdown. Drill cuttings should be collected and described at 5-feet 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 hydrocarbon shows, drill-stem 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% hydrochloric (HCl) acid. Some reservoirs need a cleanout agent prior to acidization (Campbell, 1978). In Bug field (figure 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 6) 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).

Horizontal Drilling

Introduction

Three factors create reservoir heterogeneity within productive zones in the Paradox Formation: (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 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.

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 (MWD) technology 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 7A, B, and C), (3) delays interface breakthrough (coning) (figure 7D), (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).

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. 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. Finally, a decision about drilling horizontally in Paradox Formation fields should also be based on the reservoir depth, regulatory requirements for spacing, type of application, and surface location to avoid topographic features.

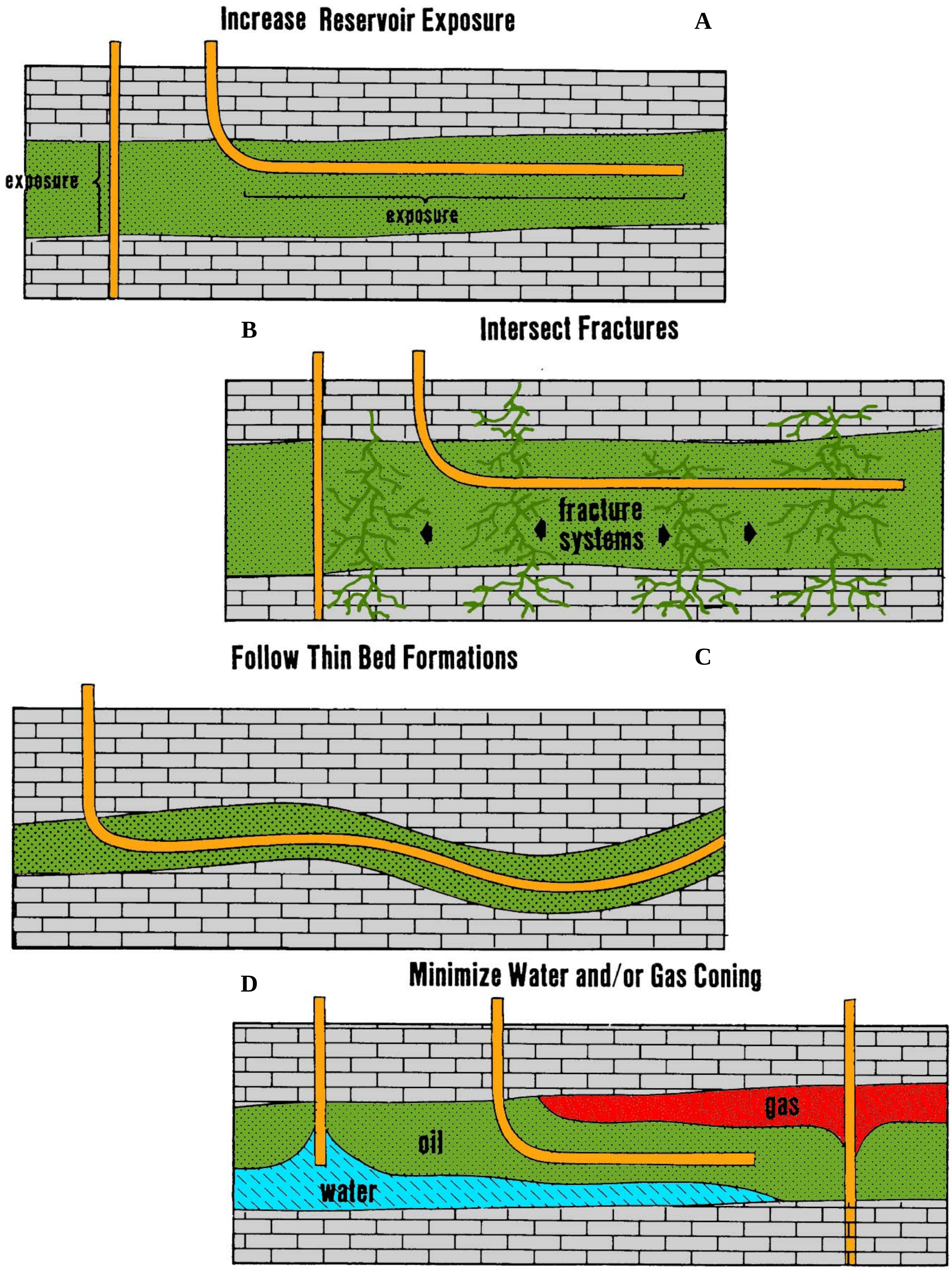

Figure 7. Reservoir conditions favorable for horizontal drilling (modified from Kikani, 1993).

Historical Aspects

With the exception of the giant Greater Aneth field (figures 2A and 6), 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 6). The results from these wells were disappointing in terms of encountering the objective reservoir lithofacies and production (Chidsey, 2002).

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, 1992). These plays targeted reservoirs dominated by fractures. At this time 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, 1992).

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 for 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

Types of horizontal wells: Horizontal wells may be classified as long reach (over 5000 feet [1500 m] in length) and short reach or horizontal laterals (200 to 700 feet [60-200 m] in length) (figure 8). The decision for drilling a particular category in Leadville 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 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 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.

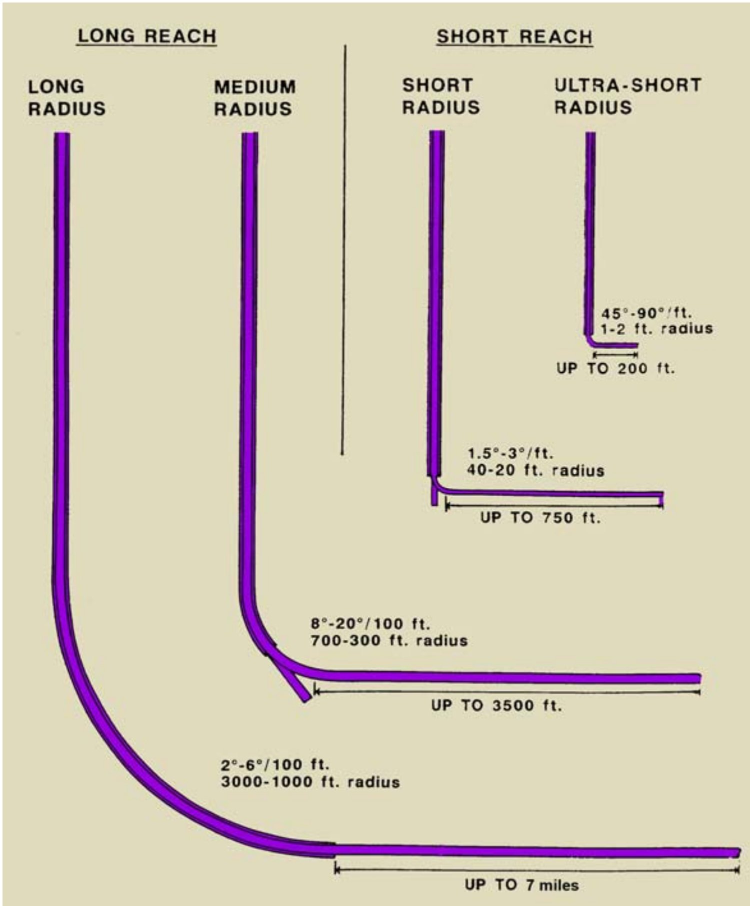

Figure 8. Diagrammatic cross section showing types of horizontal wells (after Fritz and others, 1992).

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 over 5000 feet (1500 m) of horizontal length, and allow conventional logging, coring, and 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 techniques may include new horizontal wells and horizontal, often multiple, laterals from existing vertical wells, preferred in environmentally sensitive areas. Multilaterals exiting a single wellbore (figure 9) have gained wide acceptance (Chambers, 1998). They are required where two, separate, geologically distinct zones are present. Multiple laterals can also be 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. Multilaterals are drilled for cost saving reasons or reservoir production reasons associated with improved drainage or injection. They provide a means for increasing contact with the pay zones and would target untapped reservoir compartments. Problems may include casing collapse in horizontal laterals and scale caused by certain water chemistries; the latter requires a scale-inhibitor program.

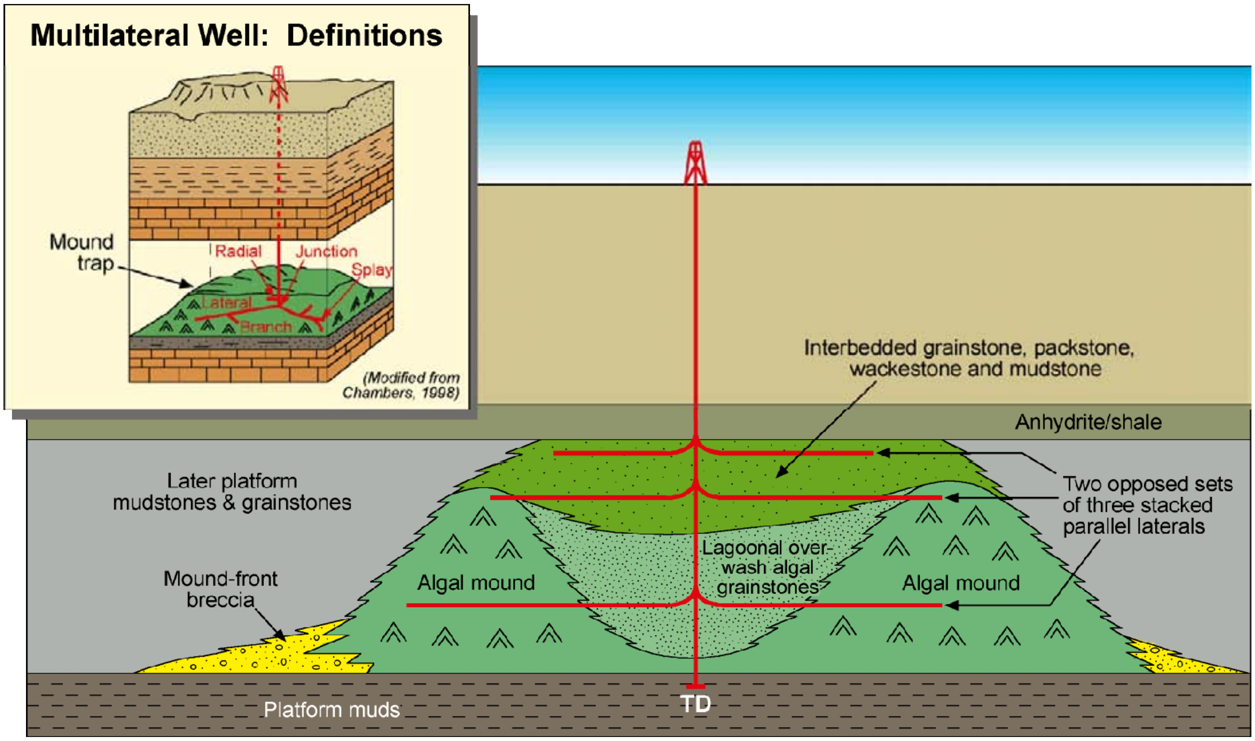

Figure 9. Schematic diagram of Ismay zone drilling targets by multilateral (horizontal) legs from an existing field well.

Drilling operations: There have been many advances in horizontal drilling technology and cost control over the last 15 years. The use of modern angle build motors 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. 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).

Cross sections serve more as a guide than an absolute target since porosity and permeability are not very predictable. Adjustments are made as the laterals are drilled using the cuttings and penetrations rates. The depth of horizontal wells must be 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 or particular lithofacies within the target zone.

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: Logging and production tests in horizontal wells typically use coiled tubing units or pipe conveyed logging. Most horizontal wells are completed open hole, with slotted/pre-perforated liners, or cemented (Kikani, 1993). Horizontal wells in the Cane Creek shale are completed with uncemented, pre-perforated liner in the horizontal leg (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 2A and 6), 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, 1992). 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 4) 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). 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.

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, 1996). 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-box-work 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.

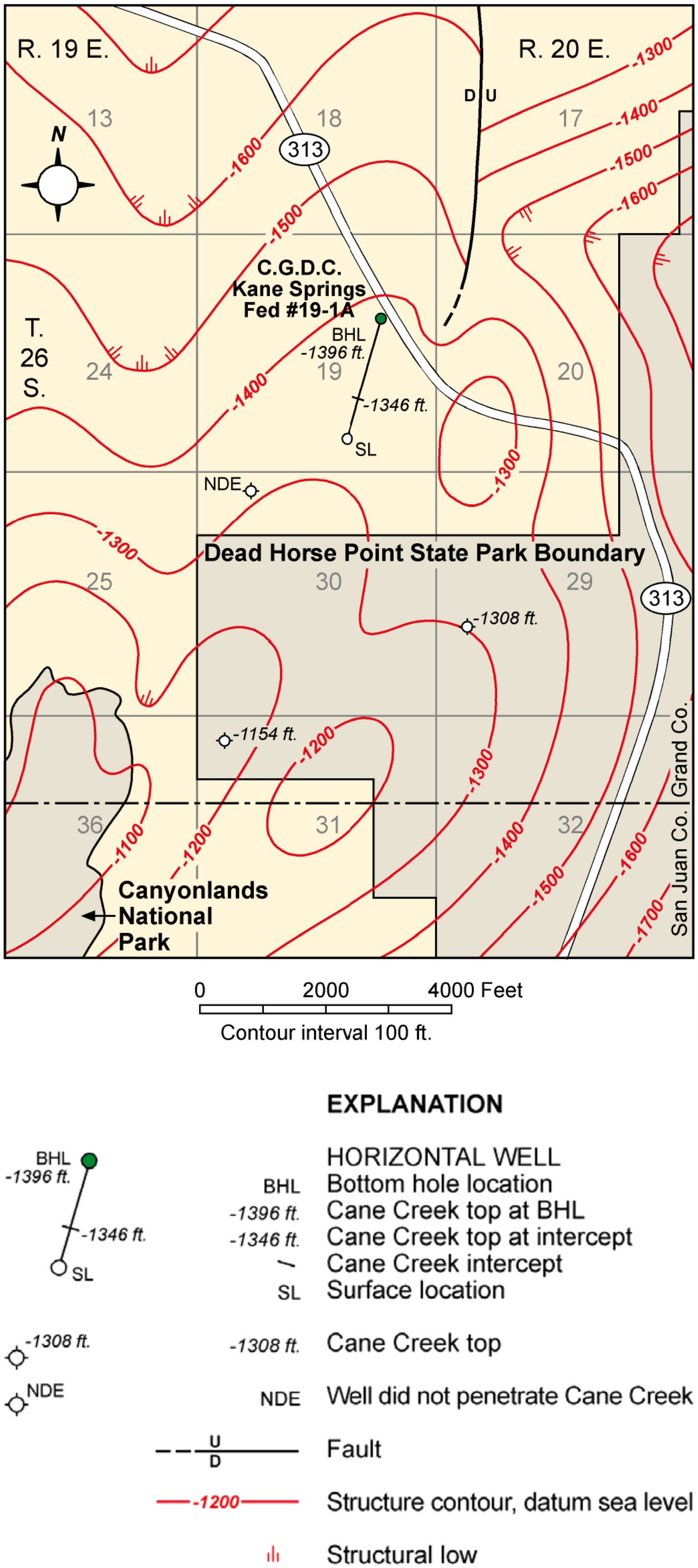

***Figure 10.** Cane Creek shale structure map, Park Road oil field, Grand County. Surface location, direction, and length of horizontal well shown (after Grove and others, 1993). See figure 4 for location of Park Road field.*

Three strategies for horizontal drilling are recommended for Desert Creek and Ismay fields in the Blanding sub-basin subplays (figure 11). 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 11A). 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 11B). 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 11C).

Aneth Platform Desert Creek Zone Subplay

An extensive and successful horizontal drilling program has been conducted in the giant Greater Aneth field (figures 2A and 6). 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 12 and 13). 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 figure 11. 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.

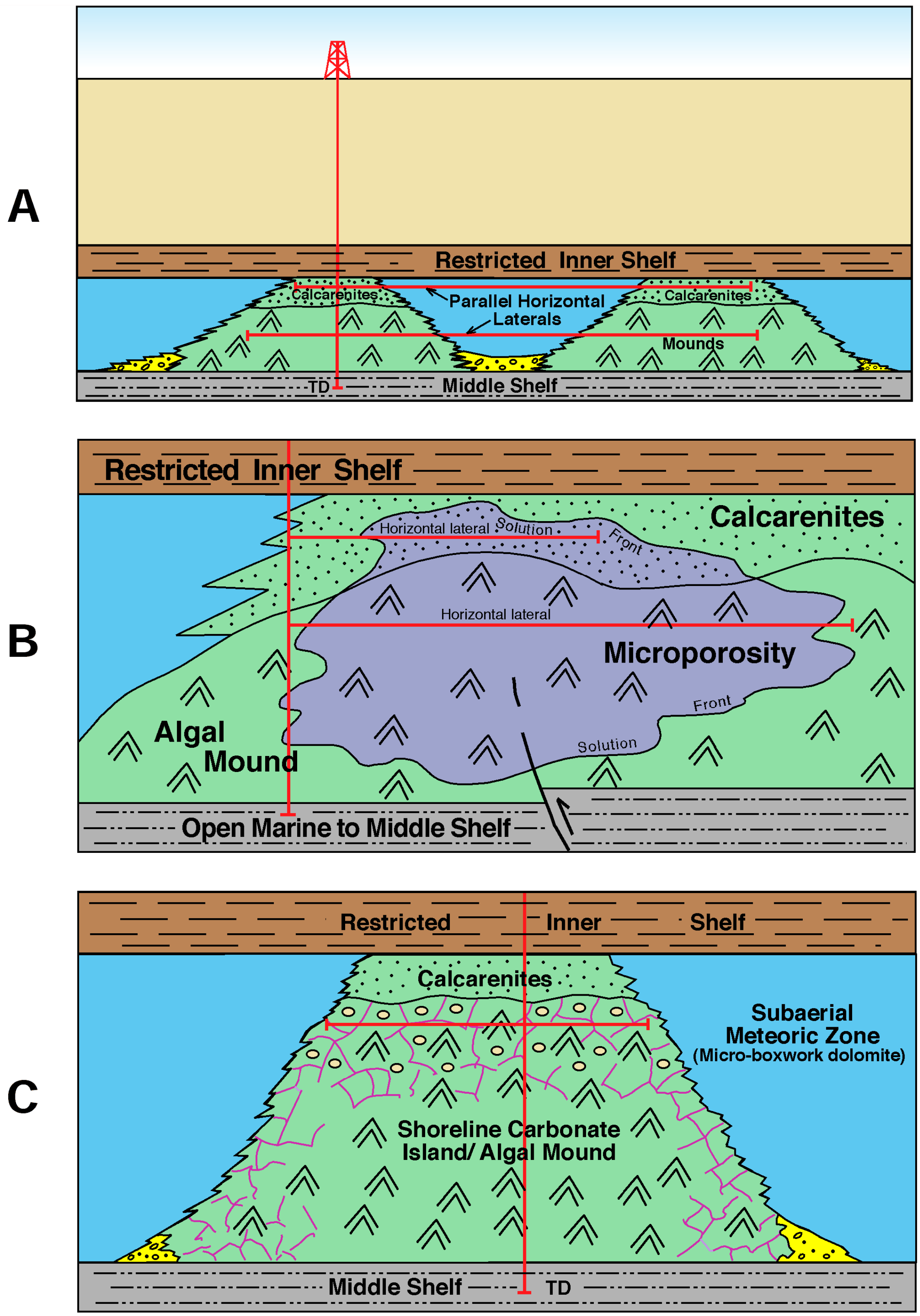

Figure 11. Schematic diagram of strategies for horizontal drilling for Desert Creek and Ismay fields in the Blanding sub-basin subplays: (A) depositional lithofacies in the Ismay and Desert Creek zones, (B) microporosity in the Ismay zone, and (C) depositional lithofacies and diagenetic fabrics (micro-boxwork porosity) in the Desert Creek zone.

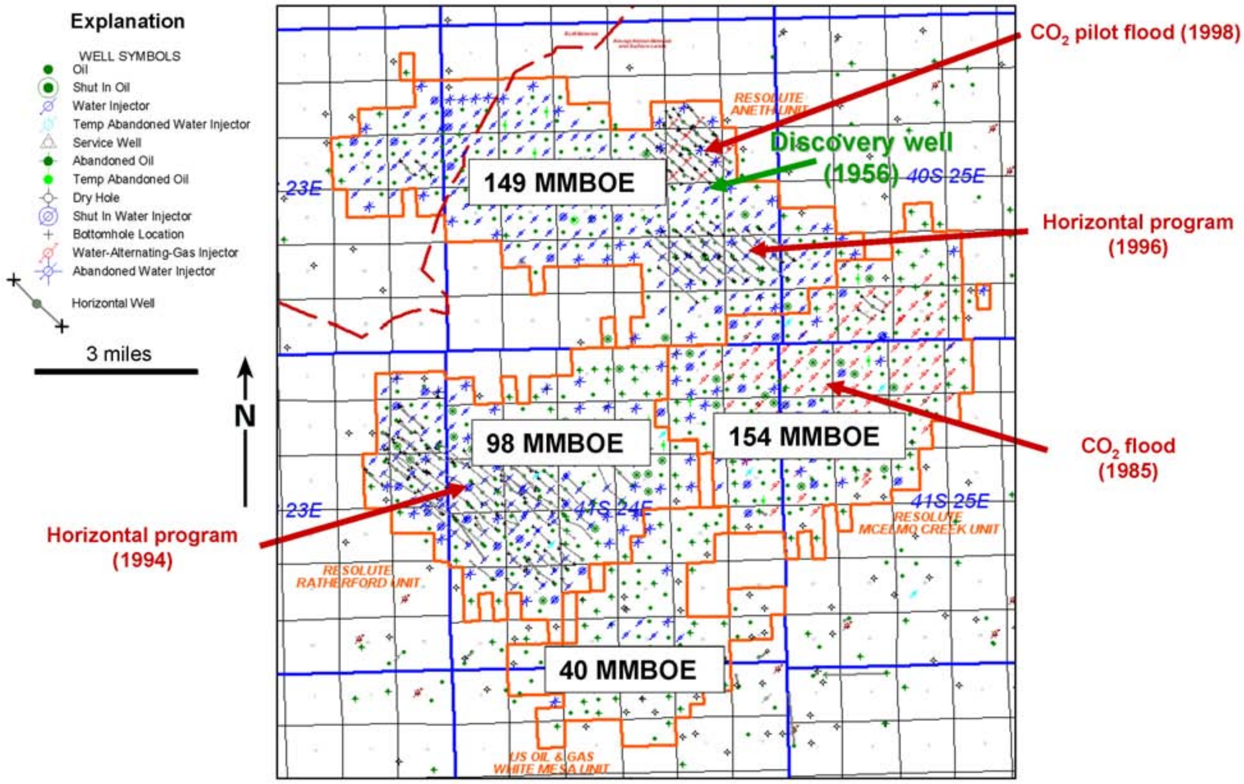

Figure 12. Best practices and cumulative production, Greater Aneth field, Utah. After Resolute Natural Resources unpublished map (2007).

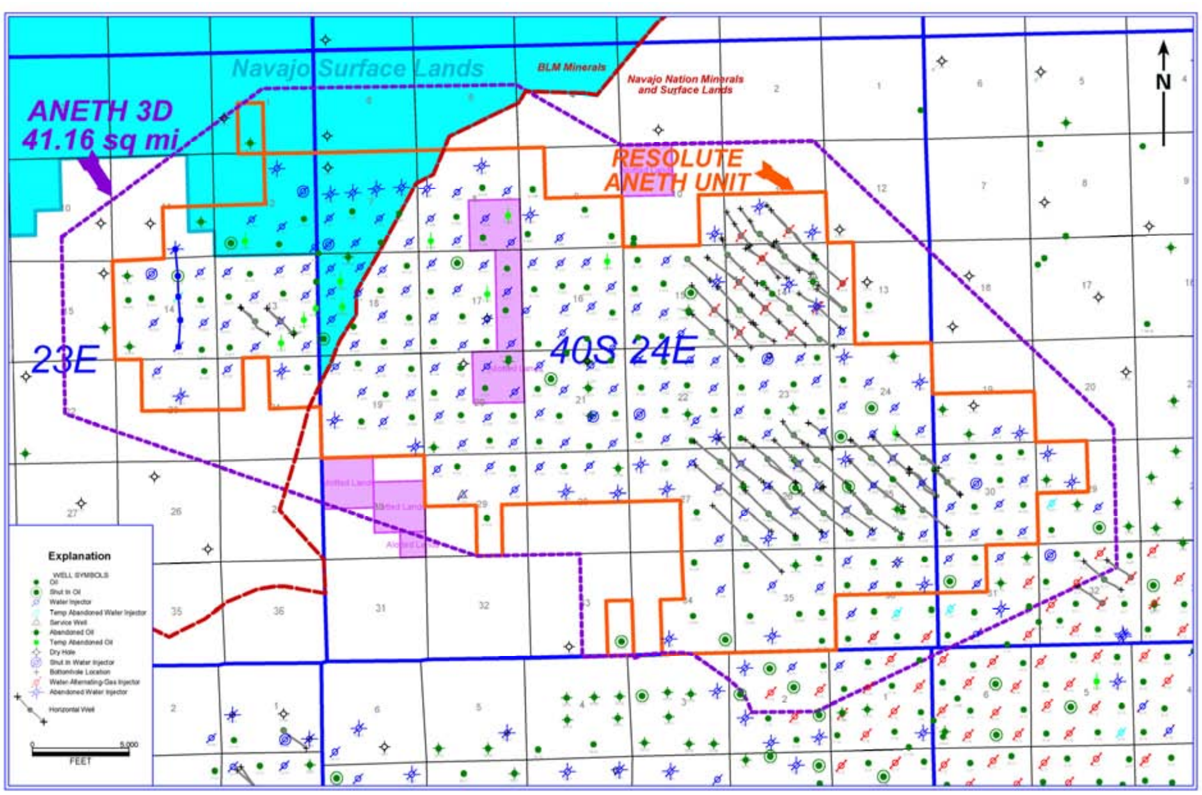

Figure 13. Base map of well types and horizontal well orientations in the Aneth unit, Greater Aneth field. After Resolute Natural Resources unpublished map (2007).

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 14). 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 15A). Ahead of the oil bank, the pore space has a high water or gas saturation (step 2 on figure 14). 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 14; figure 15B). 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 14; figure 15C). At this point, oil production declines and water production increases until the reservoir reaches its economic limit (operation cost 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

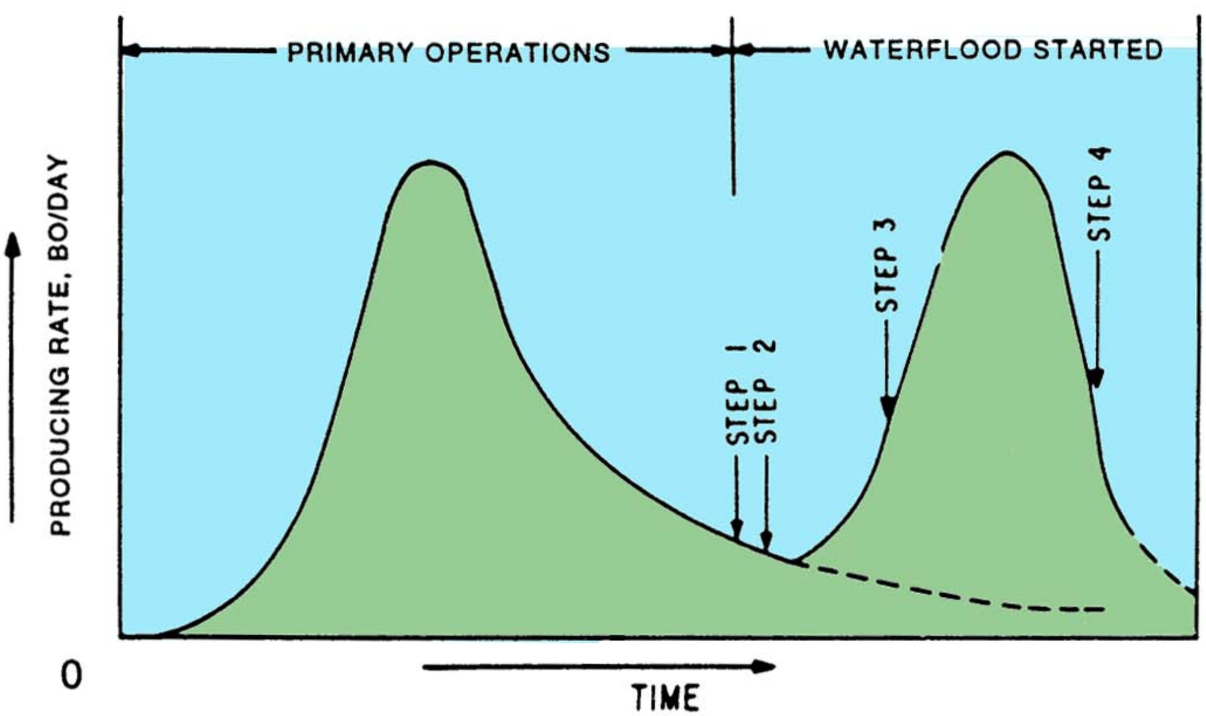

Figure 14. Primary and secondary production curves for a solution gas reservoir. After Clark (1969).

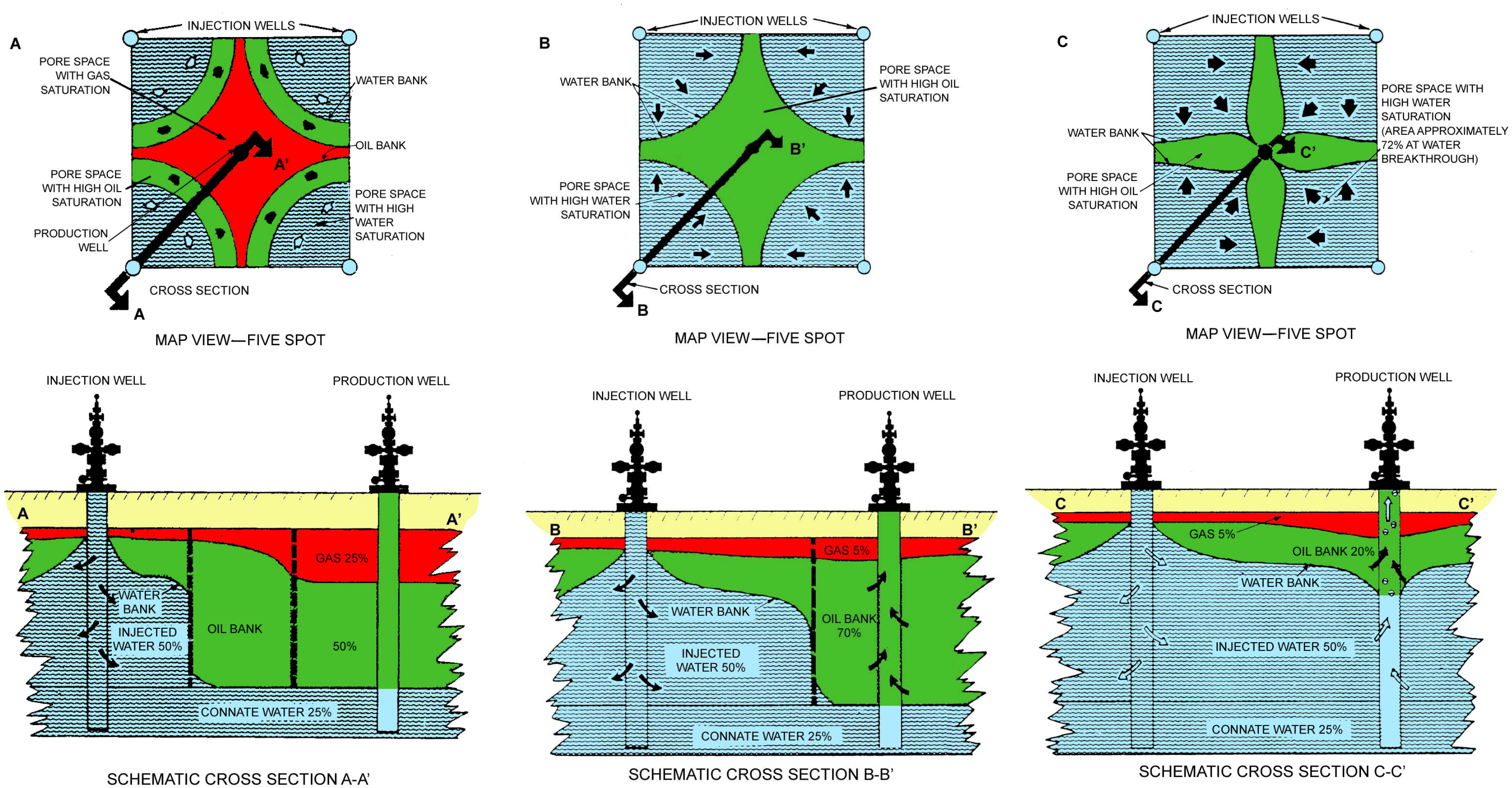

Figure 15. Areal (top) and cross section (bottom) of a five-spot well pattern under waterflood injection for a solution gas reservoir. A – Development of an oil bank in front of a water bank; step 2 of the production curve shown on figure 14. B – Major increase in oil production at fill-up; step 3 of the production curve shown on figure 14. C – Water breakthrough when the water bank reaches the wellbore; step 4 of the production curve shown on figure 14. Modified from Clark (1969).

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 6) 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, 2007). Kiva produces from the upper Ismay zone. The reservoir is a relatively narrow, elongate, northwest-southeast-trending phylloid-algal buildup (figure 16) composed of limestone and dolomite that forms a stratigraphic trap resulting from a mound to off-mound lithofacies change.

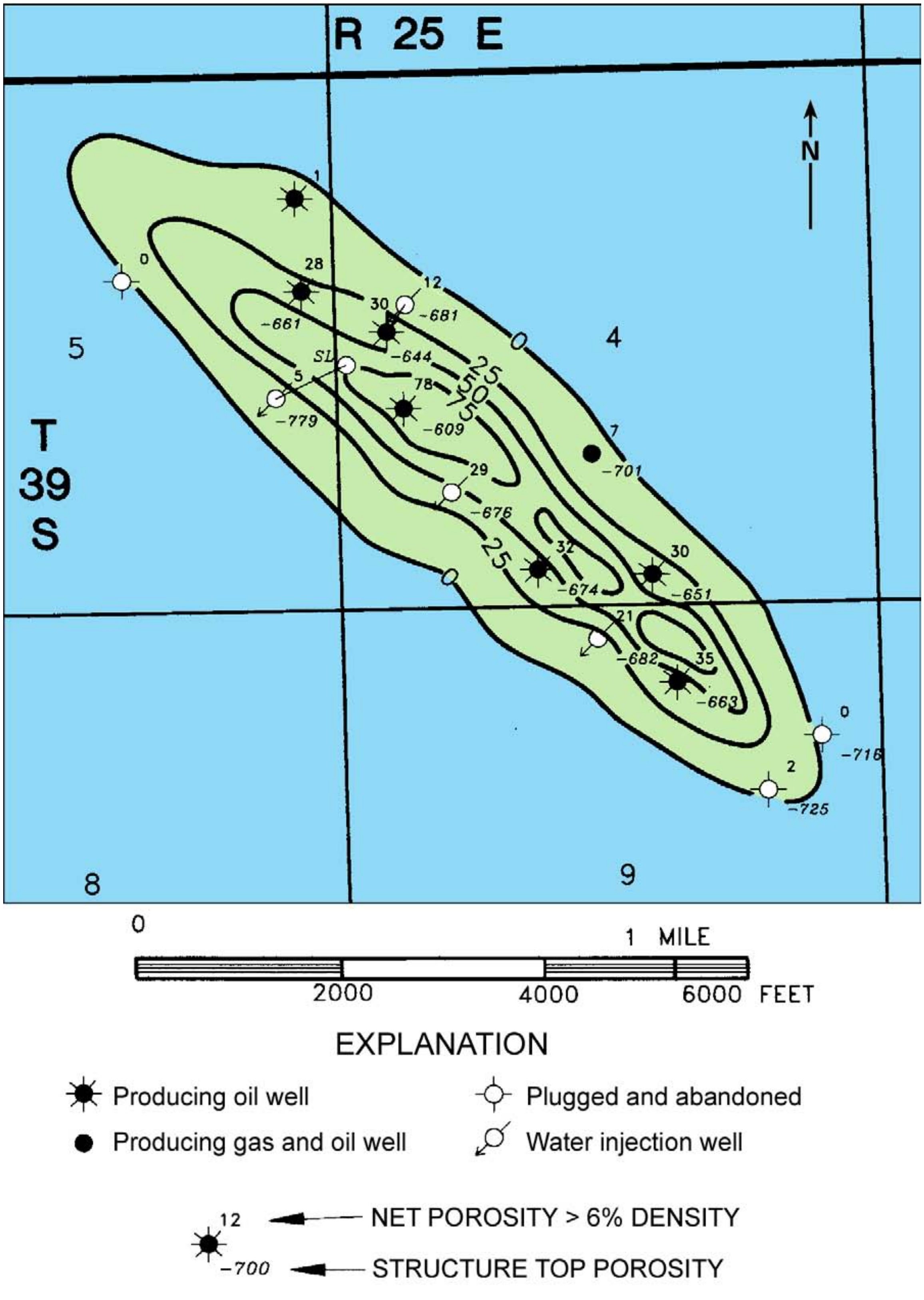

Figure 16. Upper Ismay zone isopach map, Kiva field; contour interval = 25 feet. After Crawley-Stewart and Riley (1993).

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 to the waterflood since it was initiated in 1987 (figure 17). 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 pounds per square inch (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, 2007). Kachina also produces from the upper Ismay zone. The reservoir is a small, equant to slightly northwest-southeast-trending phylloid-algal buildup (figure 18) 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 to the waterflood since it was initiated in 1989 (figure 19). 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).

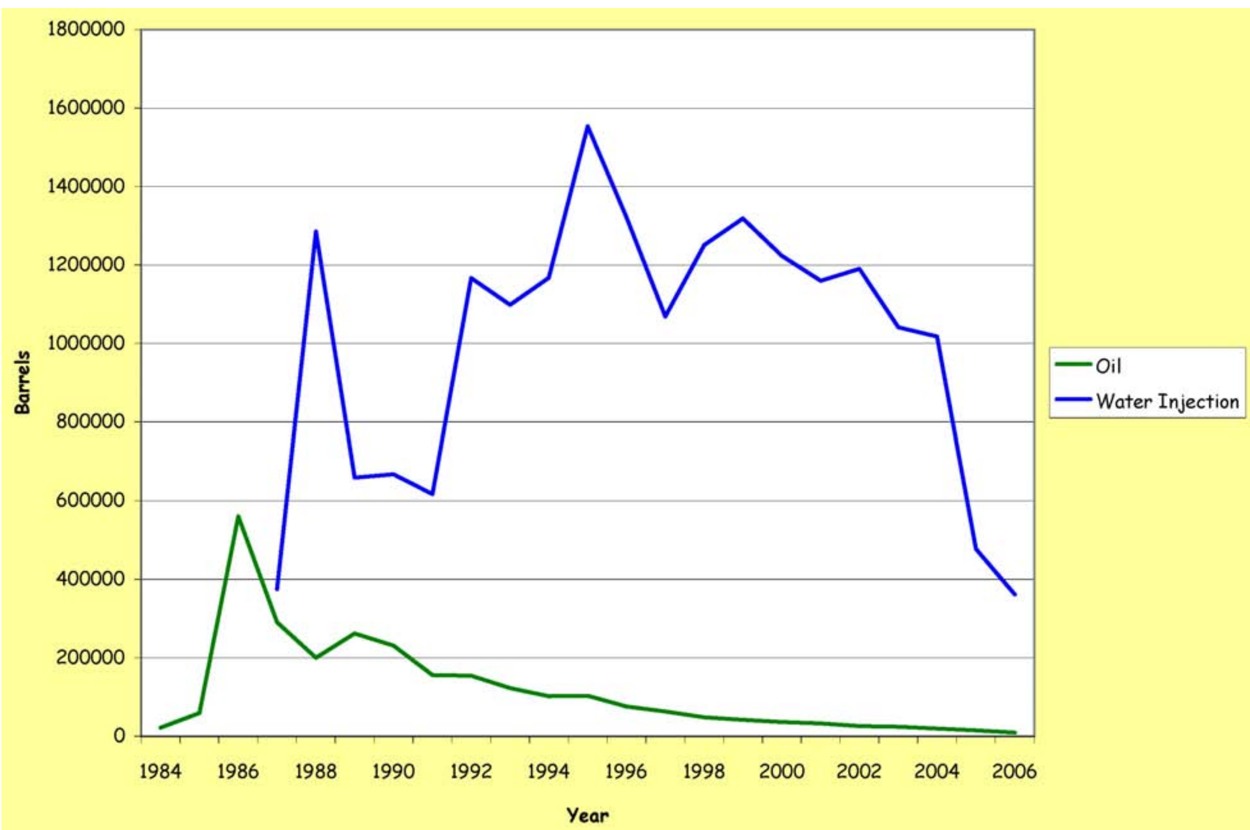

Figure 17. Production and water injection history, Kiva field. Data source: Utah Division of Oil, Gas and Mining, 2006.

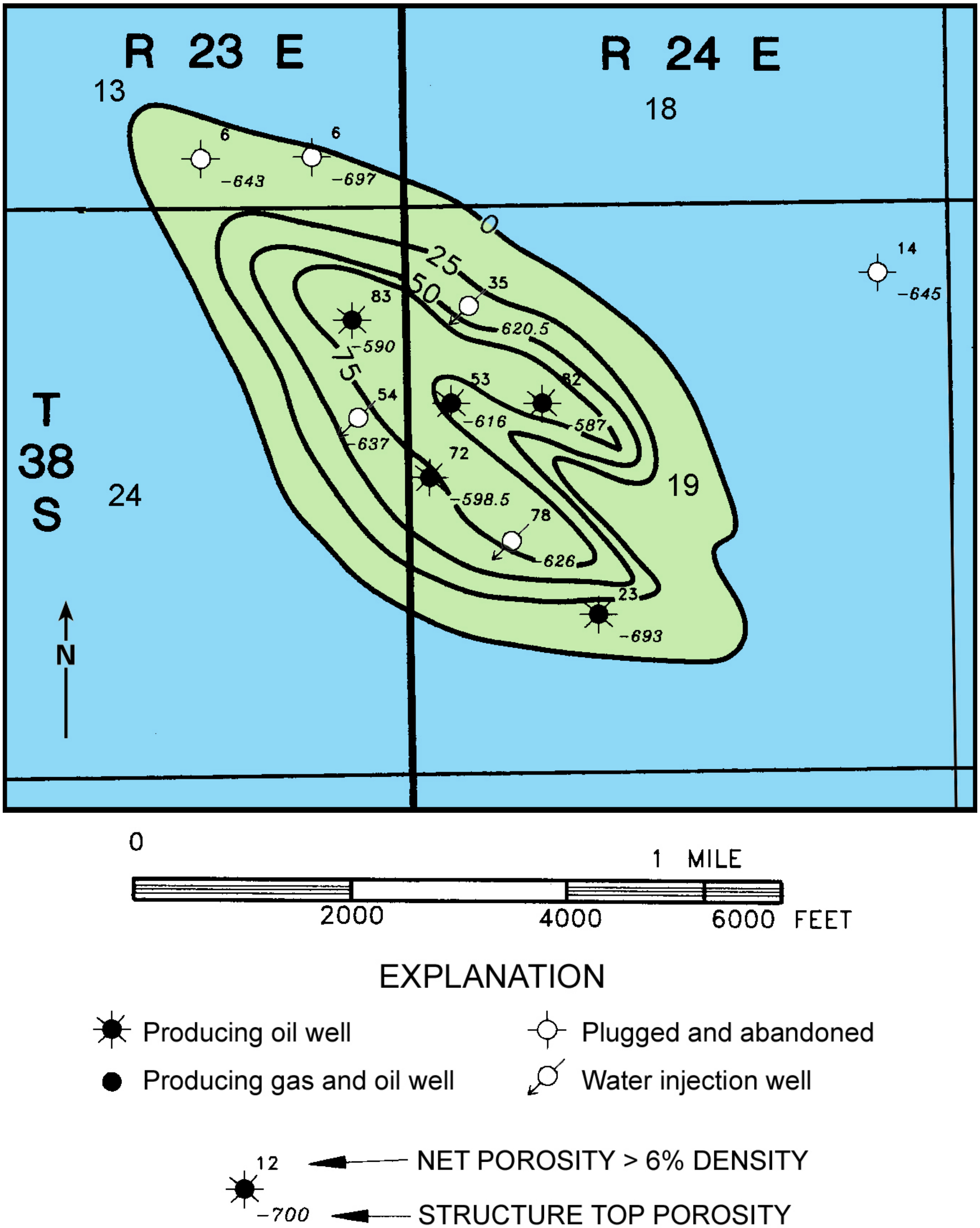

Figure 18. Upper Ismay zone isopach map, Kachina field; contour interval = 25 feet. After Crawley-Stewart and Riley (1993).

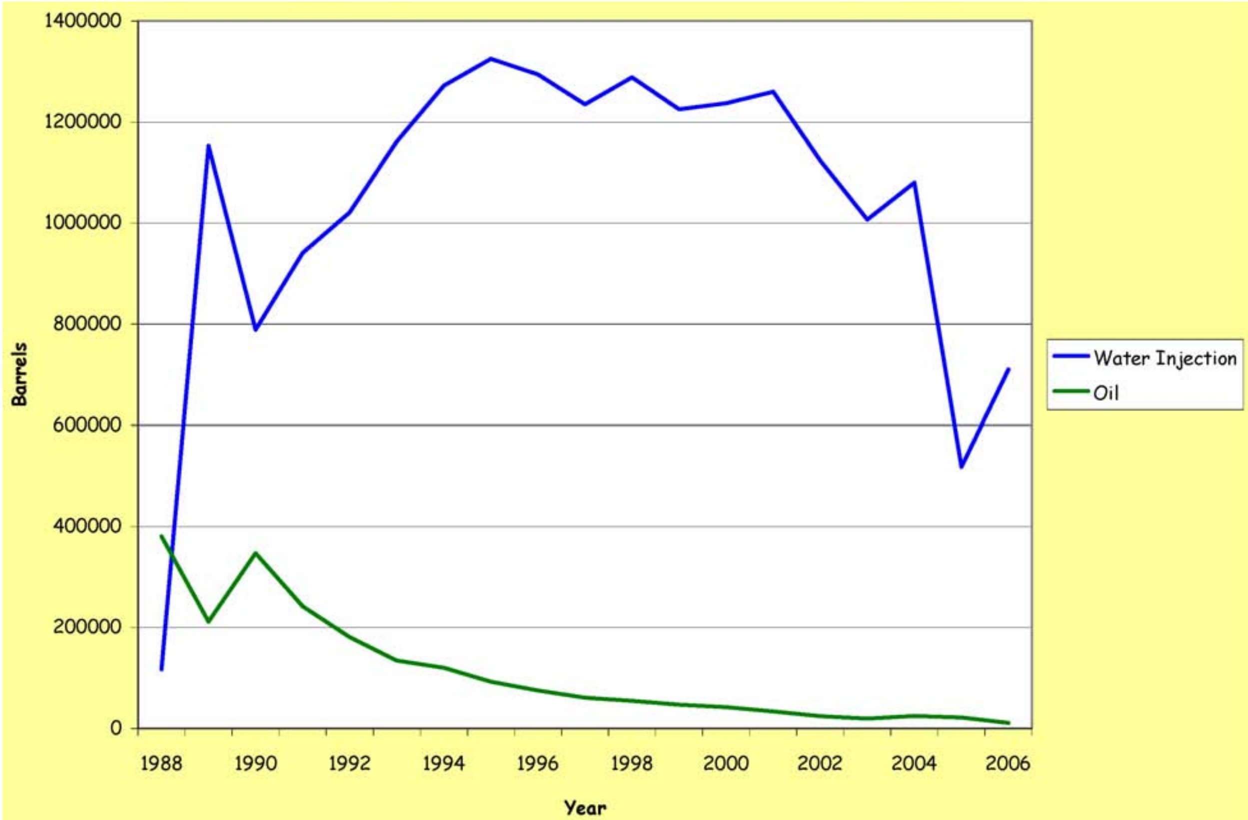

Figure 19. Production and water injection history, Kachina field. Data source: Utah Division of Oil, Gas and Mining, 2006.

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 20). 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 12) – 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 21 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) infill wells creating a five-spot injection pattern (Rudy Smith, ExxonMobil Production, verbal communication, June 22, 2004).

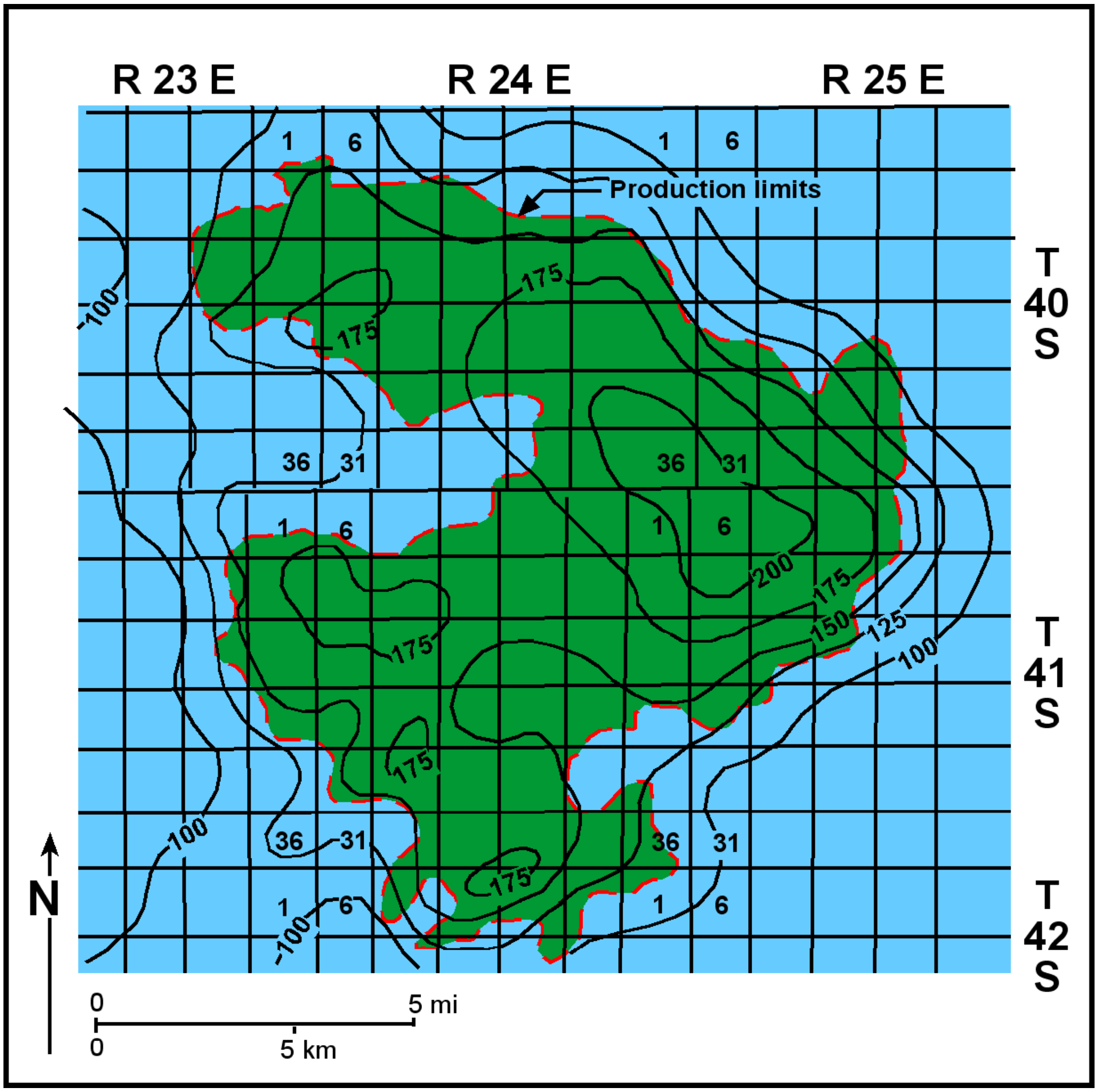

Figure 20. Generalized thickness map of the Desert Creek zone, Greater Aneth field; contour interval = 25 feet. Modified from Peterson and Ohlen (1963).

At McElmo Creek unit, areas of higher water injection correspond to high reservoir permeability (Weber and others, 1995) (figure 22). 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, 1995).

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 23A) (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 23B) and improved both areal and vertical sweep

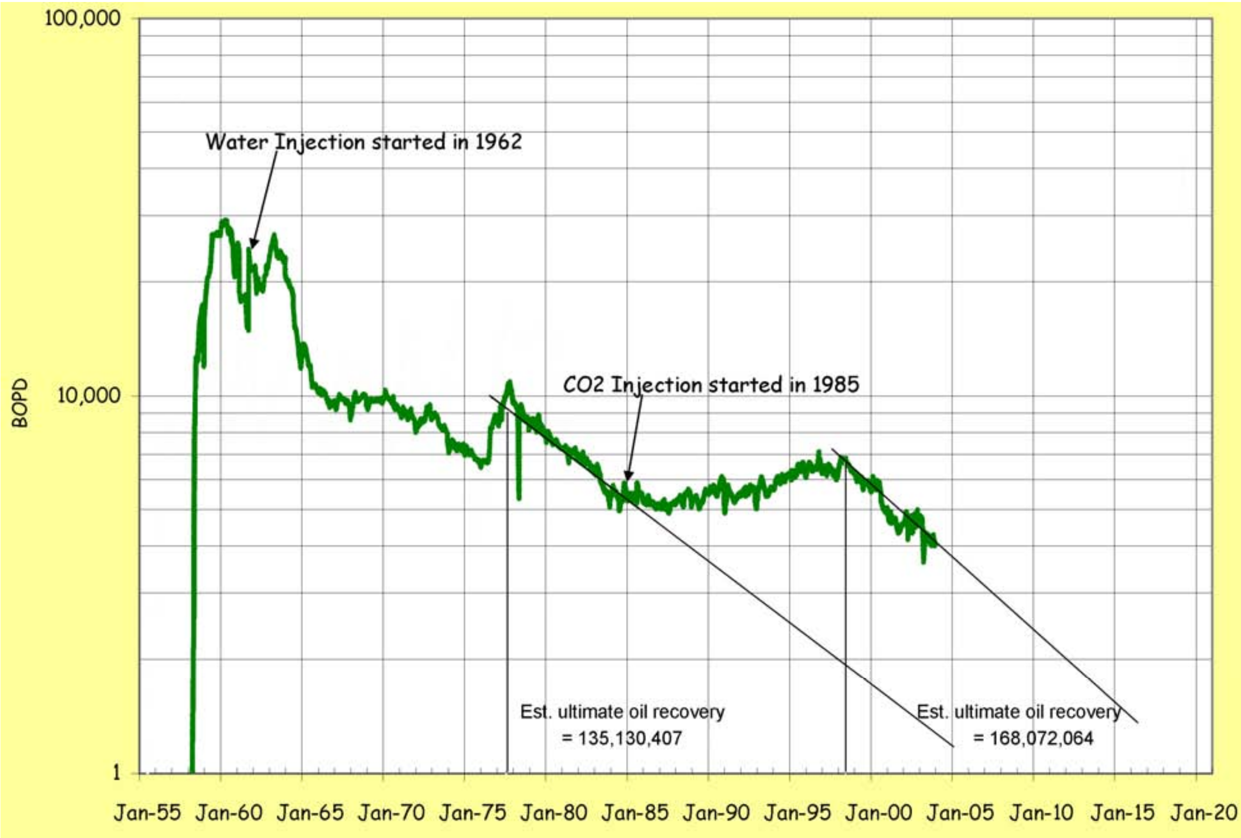

Figure 21. Oil production history from the McElmo Creek unit which uses only vertical wells for its waterflood and CO_2 flooding projects, Greater Aneth field. After Resolute Natural Resources unpublished graph (2007).

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 23B). This allows the line-drive flow to maintain reservoir pressure and more uniformly sweep oil from injection to producing wells (figure 23B) (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

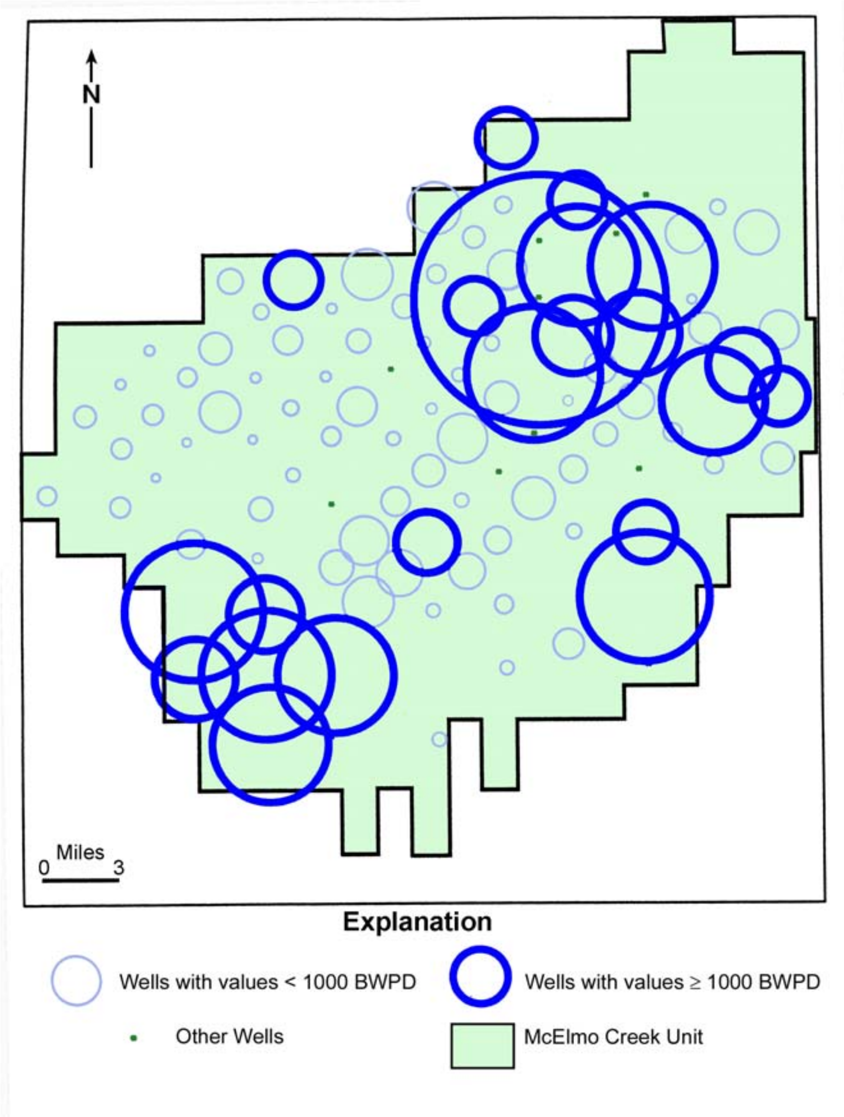

Figure 22. Maximum daily Desert Creek zone water injection rate map showing volumes in bbls of water per day (BWPD), McElmo Creek unit, Greater Aneth field. After Weber and others (1995).

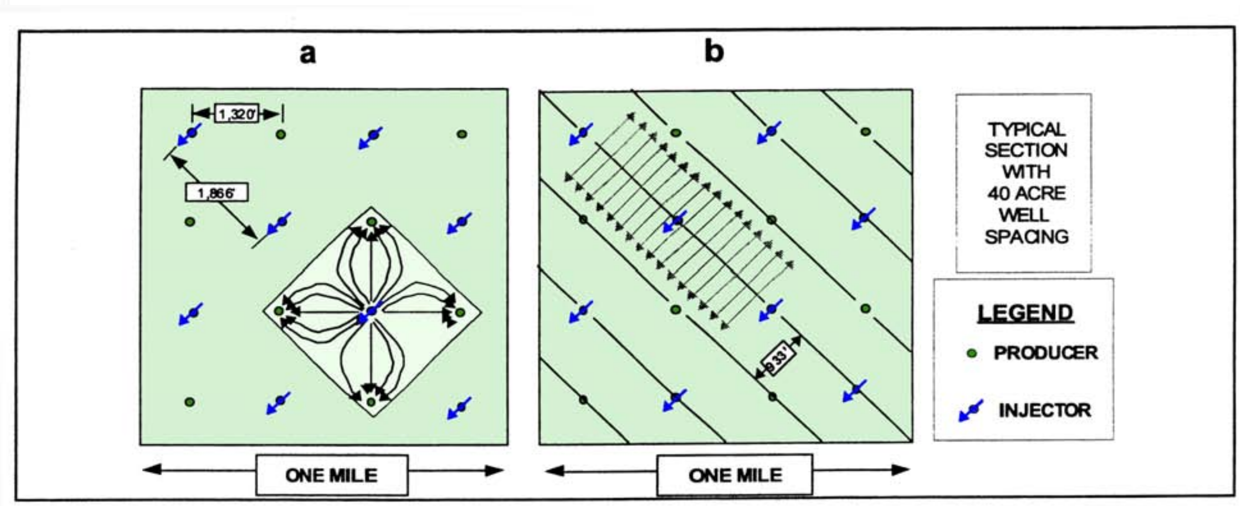

Figure 23. Waterflood flow patterns at Greater Aneth field. A – Vertical wells in a five-spot radial flow pattern. B – Line-drive flow pattern using horizontal wells. After Amateis and Hall (1997).

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 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 24). 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.

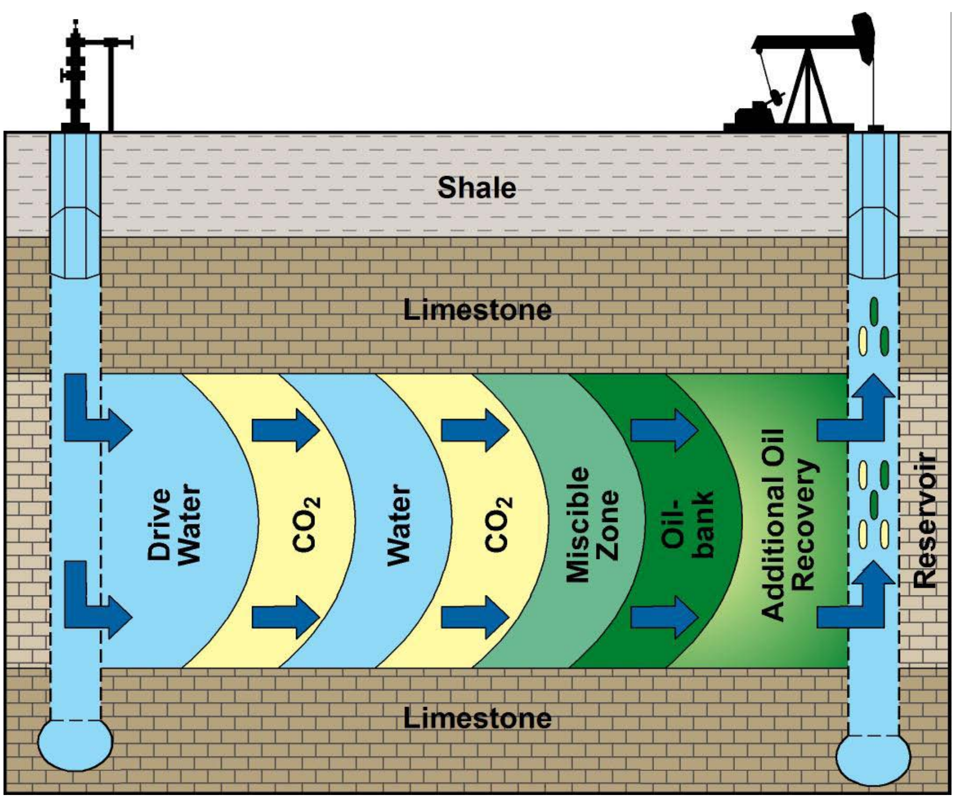

Figure 24. Schematic diagram showing water-alternating-gas (WAG) CO_2 injection.

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 6). 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 6]) 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 2A). After 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 25). 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 26), 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.

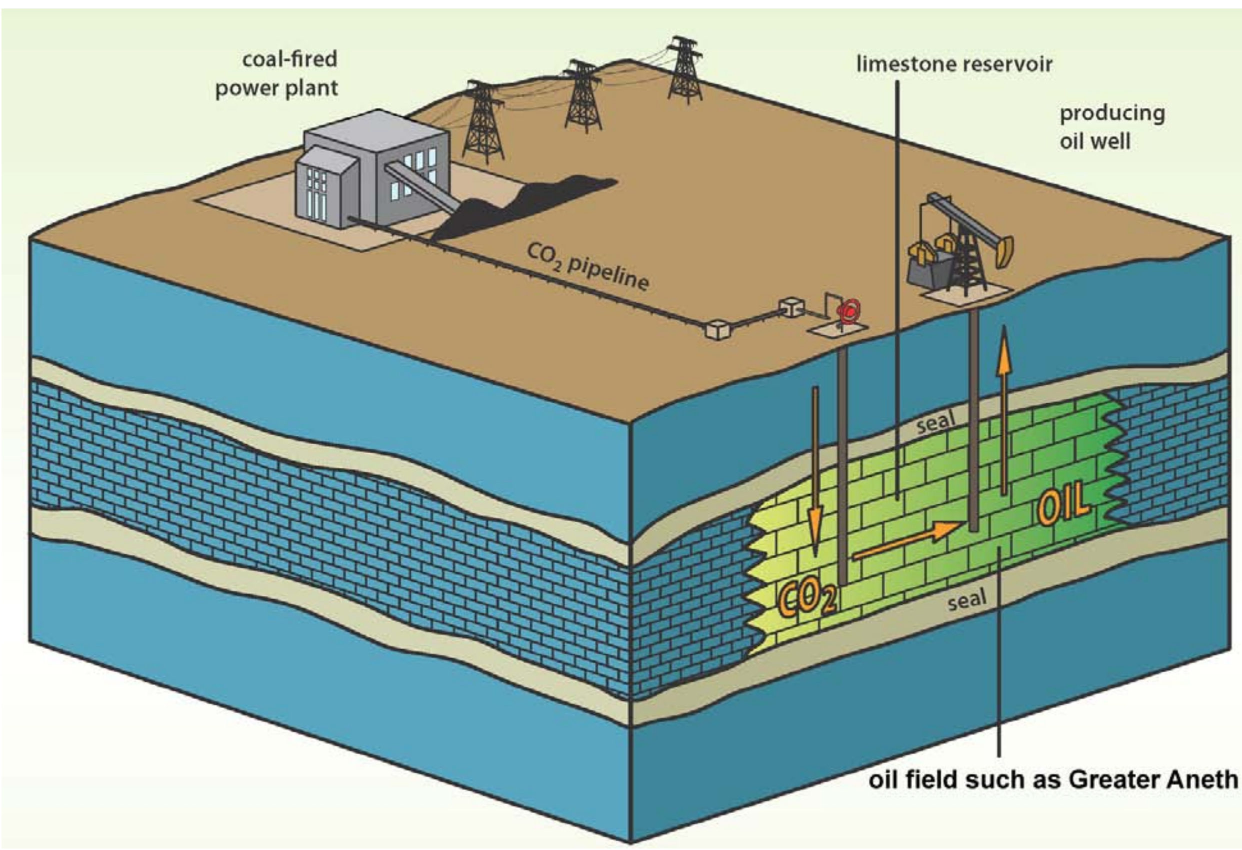

Figure 25. Schematic diagram showing possible future system of capturing and transporting CO_2 from a coal-fired power plant for use in a CO_2 flooding project for enhanced oil recovery and ultimate permanent storage in a mature oil field like Greater Aneth.

Figure 26. The McElmo Creek unit gas plant at Greater Aneth field.

Culham and Lorenz (2003a, 2003b) selected two small fields, Anasazi and Runway, peripheral to Greater Aneth (figure 6) 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 26) 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, 2007) 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.

TECHNOLOGY TRANSFER

The UGS is the Principal Investigator and prime contractor for this project under the U.S. Department of Energy (DOE) Preferred Upstream Management Program (PUMPII). All play maps, reports, databases, and other deliverables produced for the PUMPII project will be published in interactive, menu-driven digital (Web-based and compact disc) and hard-copy formats by the UGS for presentation to the petroleum industry. Syntheses and highlights will be submitted to refereed journals, as appropriate, such as the *American Association of Petroleum Geologists (AAPG) Bulletin* and *Journal of Petroleum Technology*, and to trade publications such as the *Oil and Gas Journal*.

The technology-transfer plan included the formation of a Technical Advisory Board and a Stake Holders Board. These boards meet annually with the project technical team members. The Technical Advisory Board advises the technical team on the direction of study, reviews technical progress, recommends changes and additions to the study, and provides data. The Technical Advisory Board is composed of field operators from the oil-producing provinces of Utah that also extend into Wyoming or Colorado. This board ensures direct communication of the study methods and results to the operators. The Stake Holders Board is composed of groups that have a financial interest in the study area including representatives from the State of Utah (School and Institutional Trust Lands Administration and Utah Division of Oil, Gas and Mining) and the federal government (Bureau of Land Management and Bureau of Indian Affairs). The members of the Technical Advisory and Stake Holders Boards receive all quarterly technical reports and copies of all publications, and other material resulting from the study. Board members also provide field and reservoir data, especially data pertaining to best practices. During the quarter, project team members joined Utah Stake Holders Board members in attending the Uinta Basin Oil and Gas Collaborative Group meeting in Vernal, Utah, on July 12, 2007. Project activities, results, and recommendations were presented at this meeting.

Utah Geological Survey *Survey Notes* and Web Site

The UGS publication *Survey Notes* provides non-technical information on contemporary geologic topics, issues, events, and ongoing UGS projects to Utah's geologic community, educators, state and local officials and other decision-makers, and the public. *Survey Notes* is published three times yearly. Single copies are distributed free of charge and reproduction (with recognition of source) is encouraged.

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.

Presentation

The following presentation was made during the reporting period as part of the technology transfer activities:

> "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.

Project Publications

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.

We also finalized a manuscript on the petroleum geology of Covenant field in the central Utah thrust belt play for inclusion in the Utah Geological Association's 2007 guidebook titled "Central Utah – Diverse Geology of a Dynamic Landscape."

CONCLUSIONS AND RECOMMENDATIONS

1. 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, Wyoming, and Arizona. Oil plays are specific geographic areas having petroleum potential due to favorable source rock, migration paths, reservoir characteristics, and other factors.

2. 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. 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.

3. 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.

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. Multiple laterals are recommended where two separate, geologically distinct zones are present. 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.

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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