Reasonable Foreseeable Development (RFD) Scenario for the B.L.M. New Mexico Pecos District

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Final report

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And last, a special thanks to Ronald Broadhead of the New Mexico Bureau of Geology and Mineral Resources. The geologic foundation of this work rests on the play-based analysis accomplished by Ron and his cohorts. Without this previous work, and work by others, we could not proceed.

Executive Summary

The objective of this work is to provide a reasonable estimate of development associated with hydrocarbon production in southeast New Mexico for the next 20 years, with emphasis on federal lands managed by the U.S. Bureau of Land Management (BLM). A comprehensive study of all existing plays was accomplished, including a review of recent activity, historical production and completion trends. Also investigated were emerging plays for future potential. The work is based on applying engineering and geologic principles to estimate potential subsurface development for the known producing and anticipated potential reservoirs in the New Mexico portion of the Permian Basin.

The study area encompassed four counties in southeast New Mexico; Chaves, Eddy, Lea and Roosevelt. In play-based analysis land ownership was not considered, thereby obtaining a complete picture of the reservoir potential. As a result, throughout the study total activity is reported, regardless of land status. To acquire the Federal share, we superimposed the number of completions (unique drills) on lands with Federal status from 2004 through 2011. About 40% of wells were completed on Federal lands; thus 40% is the recommended ratio to obtain Federal share of the activity.

Within the study area, new well completions are expected to slightly rise to average 800 per year (320 on Federal lands). Recent activity has seen a shift to mostly oil targets and is expected to continue on this upward trend, in part due to projections of stable and inclining oil price. Also, enhancing the increase in oil development are improvements in horizontal drilling and stimulation technology that allow producers to unlock oil in low-permeability sands and shales such as the Avalon/Bone Springs play. In 2010, horizontal wells in all plays contributed 27,000 bopd, 15% of the total region's oil production. In 2000, only 3% of the total oil production was from horizontal wells.

Corresponding with the oil trend is a decline in activity in major gas plays as a result of the low natural gas prices. For example, gas well completions for Chaves, Eddy, Lea and Roosevelt Counties combined in 2010 was only 15% of the number of completions in 2005. At the same time gas prices have declined by approximately half. With the significant supply of domestic gas from U.S. gas shale plays, gas prices are predicted to be relatively constant for the next ten years and then only slightly increase over the next twenty years. Consequently, gas plays are not projected to be in high demand.

Horizontal well activity has primarily occurred in the Avalon/Bone Springs, Abo, Wolfcamp and Yeso plays in Eddy County. The success of this current work has resulted in an inventory of locations to develop. As a result, a steady incline in number of horizontal wells is projected. A more dramatic increase is not anticipated due to limitations in manpower, equipment and infrastructure.

Other significant development will continue in the traditional Grayburg/San Andres, Delaware Sand and Yeso/Leonard plays of Lea and Eddy counties. Advances in stimulation technology have resulted in significant infill drilling potential to be developed in the Yeso play. The Delaware play will exhibit continued activity in development (infill and stepout) drilling with likely additional waterflood potential. The San Andres trends consist of continued pattern re-alignments and replacement wells in the large, prolific units such as Vacuum, Hobbs, Maljamar, and Eunice-Monument. CO_2-enhanced oil recovery (EOR) is ongoing in several of these units, with remaining pools the top candidates for expansion into CO_2-EOR.

A previous study (ARI, 2006) identified 55 reservoirs in New Mexico with 1.3 to 2.8 billion barrels of technically recoverable oil using Miscible CO_2-EOR. Eunice-Monument GB/SA field is considered to have the greatest potential; with original OIP of 2 billion barrels. Estimated ultimate recovery (primary and secondary) is 422 MMBO or 21% of the OOIP; consequently significant oil-in-place remains to be recovered.

The Woodford Shale was identified as a potential emerging play worth considering in this work. Analogous to Barnett, Haynesville and Eagle Ford shales, the impact could be high; however, after a thorough analysis, the resource potential was determined to be low and thus the corresponding development limited. The likely (high probability) development scenario proposed is the recompletion of wells penetrating Woodford but producing from deeper targets. This option incurs lower initial costs and provides more information with regards to Woodford potential.

Another emerging play investigated was Residual Oil Zones (ROZ). These zones are typically the oil saturated intervals below the producing oil water contact. They are thought to have been swept by natural water flooding processes and thus are at oil saturations too low to be produced by primary production or water floods. CO_2 EOR may be a viable means of mobilizing a significant amount of the remaining oil in the ROZ.

A simulation study was performed to assess the CO_2 enhanced oil recovery potential of residual oil zones in the Permian Basin of Southeast New Mexico. The results show that it is possible to produce from the residual oil zone by either the Water-Alternating-Gas (WAG) method or a continuous gas injection. Based on this study, the highest recovery factor attainable from the ROZ was about 5%. This is rather low figure compared to tertiary recovery rates of up 12% in the main pay zone; however, it represents production that would otherwise have been forfeited. Extrapolation of the ROZ potential to the fairways resulted in the Artesia-Vacuum trend having the highest potential, followed by the San Andres on the Central Basin Platform, the Slaughter fairway, and lastly, the Roswell trend.

One of the limitations of CO_2-EOR is the large volumes of CO_2 required in the Permian Basin to achieve the defined CO_2-EOR potential. Additional supplies from current sources (Sheep Mountain, Brave Dome, etc) and new sources (high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and others) will need to be discovered and economically feasible for development of any additional CO_2-EOR projects in the area. Pipelines are already near capacity, as is the available $CO_{2.}$ Distribution lines would also be needed. Lack of CO_2 distribution lines and supply has curtailed development of these resources.

Water production is expected to continue to increase as numerous pools and plays advance to a more mature phase of their reservoir life, and with several new developments producing high volumes of fluids. The impact of increasing water production leads to the need for expanded disposal and injection facilities. A significant portion (40%) of water production is in Lea County from massive waterflood units in the Artesia-Vacuum and Central Basin Platform (Grayburg/San Andres) plays.

A second issue with water is the expanded need for fresh water required in hydraulic fracturing. The numerous stages in a typical horizontal well stimulation significantly increases water usage; frequently requiring in excess of 4 million gallons of water per well. This is a concern in all areas in the U. S. but particularly in the desert southwest where water is in limited supply. Companies are responding by applying new technologies to recycling and re-using water. The development and application of new technologies for recycling produced and/or frac water will continue to expand to meet environmental standards and to become more efficient in operations.

All of the subsurface development mentioned above; whether infill or stepout wells, injection wells for water and/or CO_2, horizontal or vertical and disposal wells, will require access and thus additional roads to be built. Surface facilities such as tank batteries, gathering lines, etc will need to be installed and right-of-ways permitted. And last, the well locations will need to be constructed. Dedicated acreage to a typical horizontal well is 160 acres, or is equivalent to four, 40 –acre vertical wells. As a result, surface location requirements will be reduced by 70% (6.68 acres for 4, 40-acre vertical wells vs 2 acres for 1 horizontal well). A further reduction is possible with new drilling techniques capable of multiple horizontal wells from a single location. With the share of horizontal wells expected to increase, the anticipated result will be a reduction in the surface needs to permit the subsurface development.

Table of Contents

Appendix

Summary

oil and gas plays

- Abo Platform Carbonate
- Abo Shelf Sand (Gas)
- Artesia Platform Sandstone
- Atoka –Morrow (Gas)
- Avalon Sand/Bone Spring Sandstone and Carbonate
- Delaware Sandstone
- Ellenburger Karst-Modified Restricted Ramp Carbonate
- Fusselman Shallow Platform Carbonate
- Leonard Restricted Platform Carbonate
- Mississippian (Gas)
- Morrow (Gas)
- Northwest Shelf Upper Pennsylvanian Carbonate
- Northwest Shelf Strawn Patch Reef
- Pre-Permian (Gas)
- San Andres, et al.
    - Upper San Andres and Grayburg Platform Mixed—Artesia Vacuum Trend
    - Upper San Andres and Grayburg Platform Mixed—Central Basin Platform Trend
    - Northwest Shelf San Andres Platform Carbonate
- Simpson Cratonic Sandstone
- Wolfcamp
    - Leonard Slope and Basinal Carbonate and Platform Carbonate
- Wristen Buildups and Platform Carbonate (including Devonian Thirtyone Deepwater Chert)

1 Objective

In 1924, the Flynn, Welch, Yates State No. 3 well opened the first commercial oilfield in Southeast New Mexico (Lang 1935). The Jal and Hobbs fields in Lea County were discovered in 1927 and 1928, respectively, and the Permian Basin of southeastern New Mexico has continuously produced since then.

The objective of this work is to estimate a reasonable development of production in southeast New Mexico for the next 20 years, with emphasis on federal lands managed by the U.S. Bureau of Land Management (BLM). The work is based on applying engineering and geologic principles to estimate potential subsurface development for the known producing and anticipated potential reservoirs in the New Mexico portion of the Permian Basin. As a product of this effort, information will be compiled into useful formats that can be utilized by various computer applications such Geographic Information System (GIS) software programs.

The Reasonable Foreseeable Development Scenario (RFDS) is a planning tool used by Bureau of Land Management to provide a reasonable estimate of what oil and gas exploration and development activities might be proposed, should a decision be made to lease the area. Under this scenario, the RFDS projects what activities might be conducted by a mineral lessee under current and reasonably foreseeable regulatory conditions and industry interest. The RFDS is a 20-year forward-looking estimation of oil and gas exploration and development that is exclusive of other concerns that might compete for use of land in a multiple-use scenario. As such, it is information about one resource, with a projection of that resource as developed in a reasonable foreseeable manner. (Brister et al., 2005)

The report is organized into several sections beginning with the methods to collect and analyze data, followed by discussion of the results on key topics with regards to future development. Detailed individual play discussions are located in the Appendix.

1. Scope of Work

The focus of the RFD is to determine the potential subsurface development supported by geological and engineering evidence, and to further estimate the associated surface impact of this development in terms of actual wells drilled. The methods utilized for this study consist of a review of reservoir characteristics and historical production, predictive engineering production modeling, and presentation of data and conclusions in multiple formats including a report, databases, and GIS- based map displays. The work was partitioned into two areas: evaluation and potential of major existing producing plays and evaluations and potential of emerging plays. In addition, industry input was solicited on their knowledge and plans for future development, and last, dissemination of information in useful formats was accomplished by reports and GIS.

Major existing producing plays

Approximately twenty major plays have been identified and developed in the project area. The first step consisted of reviewing and compiling reservoir characteristics and historical production for each, followed by analyzing the information collected. Statistical and deterministic production analysis techniques applied to the historical production provides evidence on development trends and assists in estimating the potential in existing reservoirs for infill well development. Evaluation of the past performance will provide the extent of development for the current play, identify the trends in development and the application of any advancements in engineering or geologic methods in this development.

Emerging and potential plays

Evaluation of emerging and potential plays relies more on geologic evidence to support development with minor contribution from existing well development. However, over the twenty year time frame, these plays may become significant. For example, applications of new technologies have resulted in significant improvement in production for shale plays such as the Bakken Shale in the Williston Basin of North Dakota and Barnett Shale in the Fort Worth Basin of Texas. Neither the Bakken or Barnett development are in the study area; however analogous shale plays; e.g., Woodford, were examined for similar potential.

3. Approach

3.1 Data Acquisition

To discern past activity trends and ultimately predict future trends a good historical profile is required. Towards this end, pool production and well count data from 1945 onwards was obtained. Well-by-well data is unnecessary, and very difficult to obtain, so we are focusing on pool- and play-based production trends. Older data (pre-1970) was acquired from the production books that have been published annually by the New Mexico Oil and Gas Engineering Committee. To be compatible with recent production, the older data was digitized and entered into a database. More current data was obtained from GO-Tech and IHS's PI/Dwights®

Next, since we are using multiple data sources, the data was merged and reconciled for consistency. This merging datasets was a non-trivial task due to changes in pool names and data reporting formats, along with the necessary quality control required in any digitization project. Historical production data of the individual pools were showcased in the form of lifetime production curves. All current pools in southeast New Mexico are listed in our database. Where possible, other data was compiled, including pool creation and expansion dates, acre spacing and spacing changes, number of wells by year, annual cumulative production, and lifetime cumulative production. Regulatory information on spacing and pool development was obtained from the New Mexico Oil Conservation Division (NMOCD).

Another key task was the assimilation of geological data regarding each play and the significant pools within the play. Most geological information was gathered from books from the Roswell Geological Society, New Mexico Bureau of Geology and Mineral Resources, Rocky Mountains Atlas and the Texas Oil and Gas Atlas. Finally, we collected information about technology including data on completions, recompletions, changes in production methods, and pertinent regulatory changes that have taken place throughout the life of a given play. Most of this data was collected from scout cards, digitized well files that are available online, and various publications of the Roswell Geological Society.

The last step was to perform a quality check of all of the data to remove any spurious data or entry errors.

3.2 GIS database

A significant amount of data has been provided in GIS format by the BLM field office. We are creating our own database and GIS system to store this information, so we can add production statistics, boundaries, and other geographically-based data as acquired or developed. A GIS database was created that can be used and manipulated by the various workers at NMT, while still maintaining the integrity of the geodatabase as a whole.

Pool Maps – Creating a new set of Pool Maps

Although there is a published set of digital pool maps for the state, (Read, et al, 2000) it was not adequate to our needs for a number of reasons. The maps were out of date, did not correspond to the land grid selected for use in this study, and contained errors, discrepancies in nomenclature, boundaries, and locations, and were not able to be matched to pool names and codes as provided by the New Mexico Oil Conservation Division, the agency charged with tracking oil and gas production in the state. A lengthy process was involved in editing the existing maps and making the database more useful to this study.

Sources:

Two primary reference sources were used for the project. The first of these was a publication by the New Mexico Bureau of Geology and Mineral Resources (NMBGMR), Circular 209, "The Morrow Play" project. This is a digital publication that contains GIS-formatted maps of pools within the state, and it was the starting point for this effort. The second data source is a database maintained by the NMBGMR that contains information about pool boundaries. The database (unpublished but referred to in this document as the R-Order Database) is compiled by Bureau personnel from records and orders published by the New Mexico Oil Conservation Commission concerning the naming and extents of various pools in New Mexico. In the R-Orders, pool boundaries are described by use of the Township/Range/Section and either Quarter-quarter or lot number.

Problems in the GIS maps and database:

The pool maps as originally published by the NMBGMR were problematic in several ways. Chief among these were:

1. Pool boundaries were not coincident with the land grid that chosen for use in this project. (New Mexico Cadastral NSDI Geodatabase Version 1).
2. Some pool boundaries were not correct or up-to-date.
3. Pools in the original maps were made up of multiple polygons, rather having one unique polygon for each pool, so maps, labels, and database associations are more cluttered and confusing (See Figs. 3.1 and 3.2).
4. Pools in the original GIS database were not matched with their corresponding Pool Codes. Pool Codes are unique identifiers, issued by the New Mexico Oil Conservation Division, and used by them to track production for a given pool. Pool codes are associated with a particular pool name. (Pool name is a combination of the geographic area or field the reservoir is producing in, and the formation or reservoir the particular reservoir is believed to be producing from. One field can produce from many pools, for example in the Maljamar area, there are many pools – Majlamar Abo, Maljamar Devonian, Maljamar Yates, etc, and each of these pools has its own unique name, code, and set of boundaries).
5. The original pool maps had errors in spellings of names, and some ambiguities or errors in pool boundaries.

Process:

Circular 209 subdivided the oil and gas pools of the Permian Basin into a number of different "layers" based roughly on producing formation or group of formations, eg., Delaware, Bone Spring, San Andres/Grayburg, etc. Each map layer had anywhere from 12 to 350 pools associated with it. The same procedure was followed for each layer.

1) Boundary Dissolution. The first necessary step in our editing procedure was to dissolve the internal boundaries in a given pool so that a pool consisted of only one polygon with no internal boundaries. While there is an automated process to do this within the GIS program we used (ArcMap), the results required much additional manual editing.

2) Comparison with R-Order database. The second step of the process involved comparing the mapped pool boundaries with those described in the R-Order database. Efforts were made to verify that parcels were correctly identified and mapped. Sometimes this required verification with the actual R-Order documents available through the OCD's web site.
3) Adjustment of boundaries to new land grid. At the same time, the pool boundaries were edited to be coincident with the land grid used in the project. This required manual editing of almost every boundary for every pool. The land grid used by the original publication did not have quarter/quarter divisions so all boundaries that used the smaller subdivisions were hand-drawn and required significant correction.
4) The next step in the editing process involved matching pools in the maps with the actual OCD Pool Code assigned to it, correction of spelling errors in pool names, and creation of a standardized method of nomenclature. The OCD Pool Code list itself has incorrect and anomalous names. For example the Seven Rivers Formation may be referred to as 7 RVRS, SVN RVRS, 7 RIVERS, 7 RVS, or SEVEN RIVERS. We have created a modified version of the Pool Code and name list for our own use that corrects spelling errors, uses standardized spellings and abbreviations, and puts directional modifiers such as East or South immediately after the pool name, so that Maljamar;Yeso, West becomes Maljamar West and the associated formation name is moved to a different column. Standardizing naming conventions produces a cleaner map, and helps when trying to match this database with others such as that used by Dwights/IHS.
5) Full population of database. Once pool names are correct, pool codes are assigned, and pools are correctly placed, other attributes can be assigned to pools that may aid in mapping efforts. Such attributes may include production information, codes linking pools to other data, producing formations or zones and the like. A particularly significant attribute for this project would be assignment of each pool (where possible) to the play it was included in. This might not be the same play as it was mapped within the original publication.
6) Comparison with the OCD Pool Code list. The final step in the process would be to cross-check the complete list of mapped pools with the official list of pool codes to determine which pools, if any, have not been mapped. A cursory comparison of the maps with the list shows that not all pools are mapped, but this final step has not been performed yet, so the extent of the discrepancy is unknown, but probably small. If a pool is not mapped, but its boundaries can be determined from the R-Order database, the polygons will be added to the appropriate layer. The mapped database contains 2788 separate entities, while the Bureau R-Order database shows 2943 pool names for southeast New Mexico.

The following figures demonstrate the problems and process associated with building the new Pool Map database.

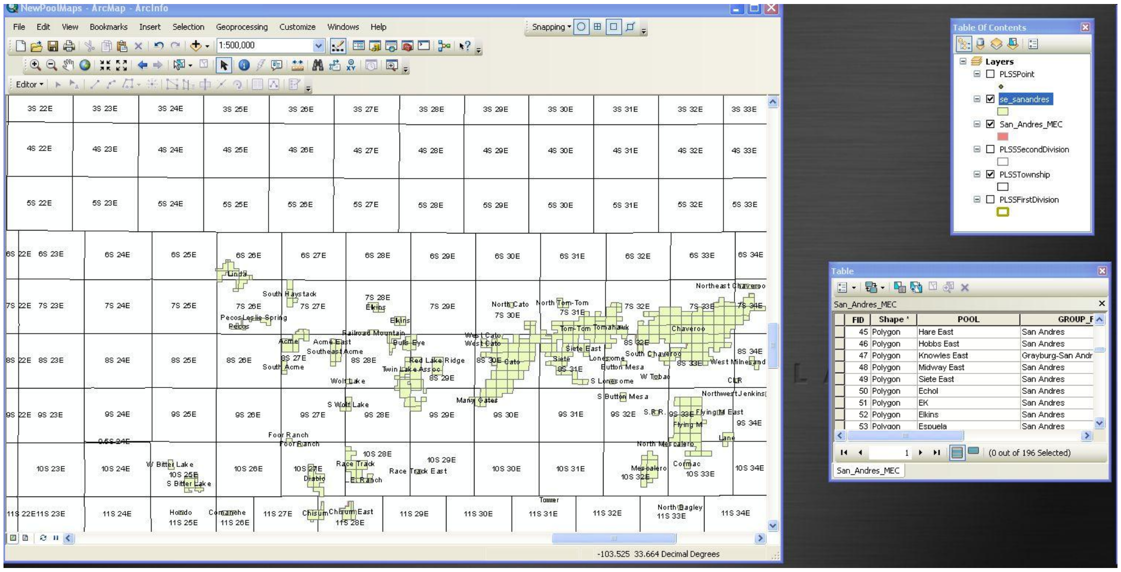


Figure 3.1 Screen shot of the original pool map boundaries from Circular 209. This particular layer is the San Andres layer. Internal boundaries can be seen in almost every pool.

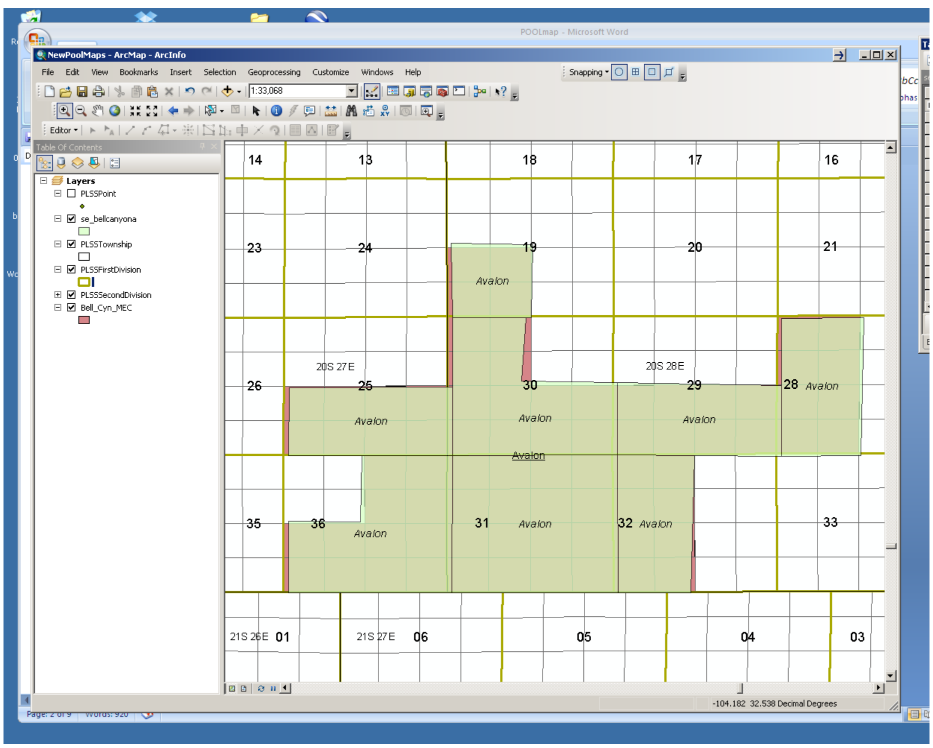


Figure 3.2 Screen capture showing a more detailed comparison of the old pool map (overlying layer with green polygons) with the edited pool boundaries (underlying layer with brownish color). This is the Avalon Delaware pool. It can be seen the old pool has internal boundaries, and that its boundaries are not coincident with the land grid, particularly noticeable in Section 30.

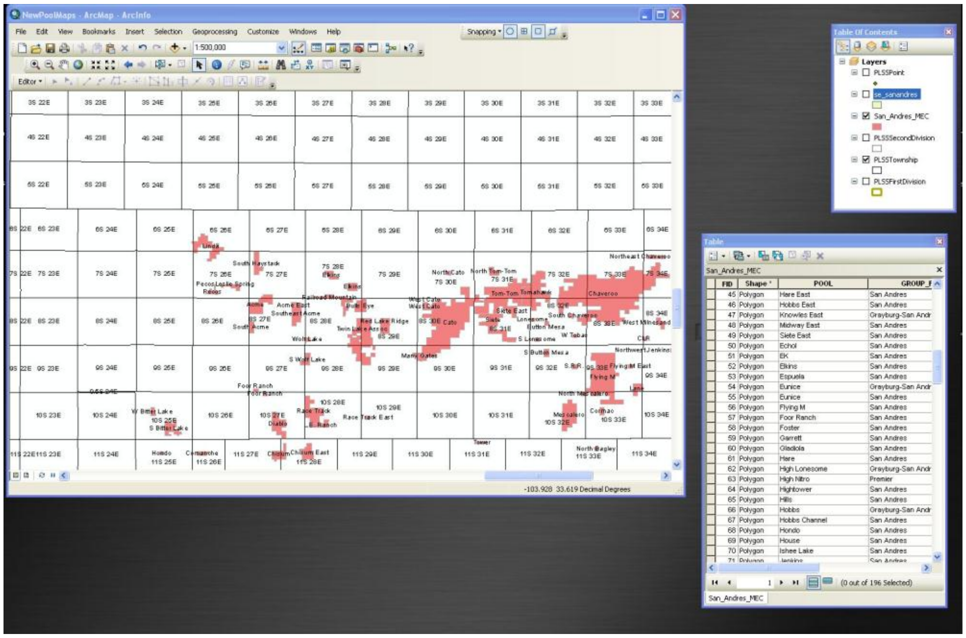


Figure 3.3 Figure demonstrating result of dissolving internal boundaries within pools. This is the new San Andres layer, as compared to Fig. 3.1.

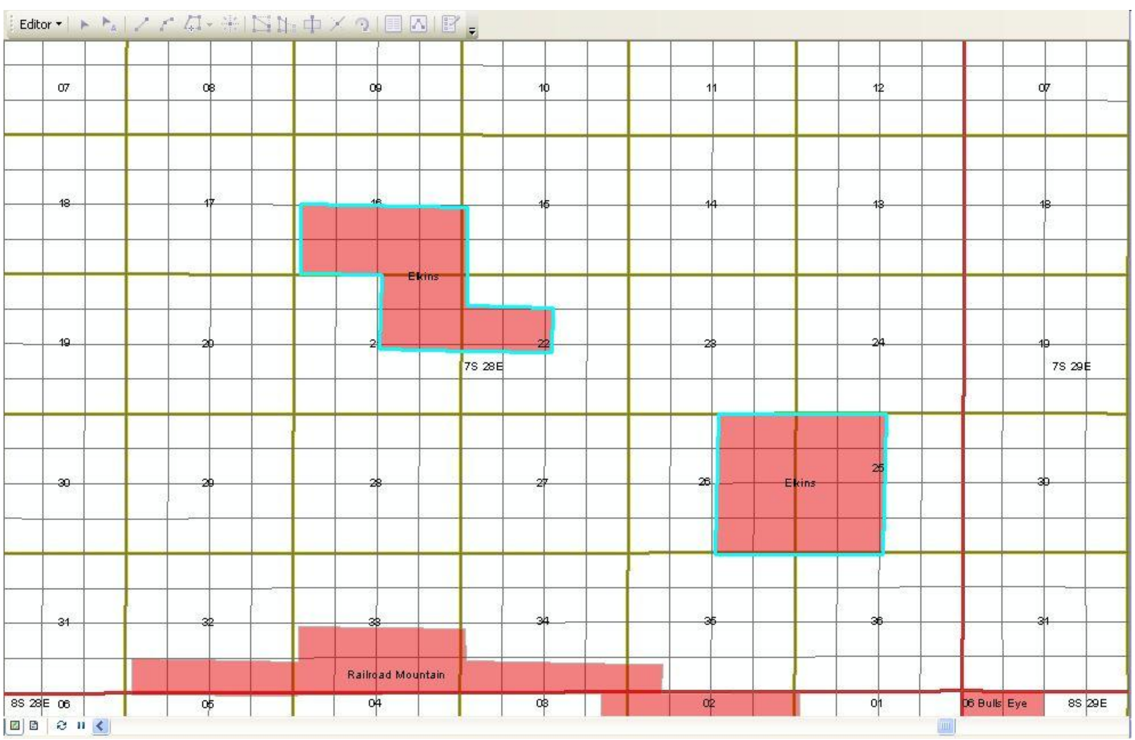
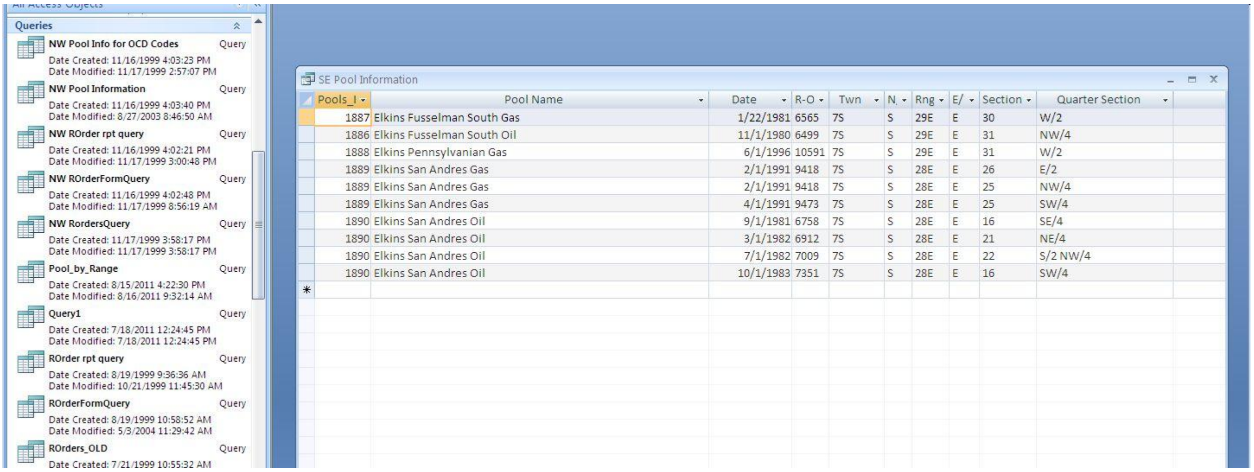


Figure 3.4. Detail of San Andres Elkins pool after dissolution of boundaries. Problems include misalignment of boundaries, and existence of two distint polygons with the same name. In this case, there are actually two San Andres pools named Elkins, with two distinct OCD Pool Codes and Names: #21730 Elkins;San Andres and #76373 Elkins;San Andres (Gas). For this project, this pool was divided into two separate pools to correspond with the OCD-assigned codes and names.



Pools_I	Pool Name	Date	R-O	Twn	N	Rng	E/	Section	Quarter Section
1887	Elkins Fusselman South Gas	1/22/1981	6565	7S	S	29E	E	30	W/2
1886	Elkins Fusselman South Oil	11/1/1980	6499	7S	S	29E	E	31	NW/4
1888	Elkins Pennsylvanian Gas	6/1/1996	10591	7S	S	29E	E	31	W/2
1889	Elkins San Andres Gas	2/1/1991	9418	7S	S	28E	E	26	E/2
1889	Elkins San Andres Gas	2/1/1991	9418	7S	S	28E	E	25	NW/4
1889	Elkins San Andres Gas	4/1/1991	9473	7S	S	28E	E	25	SW/4
1890	Elkins San Andres Oil	9/1/1981	6758	7S	S	28E	E	16	SE/4
1890	Elkins San Andres Oil	3/1/1982	6912	7S	S	28E	E	21	NE/4
1890	Elkins San Andres Oil	7/1/1982	7009	7S	S	28E	E	22	S/2 NW/4
1890	Elkins San Andres Oil	10/1/1983	7351	7S	S	28E	E	16	SW/4

Figure 3.5. Screen shot of R-Order Database showing the parcels of land associated with the Elkins San Andres pools. In general, maps were fairly accurate reflections of the database, although there were found to be discrepancies.

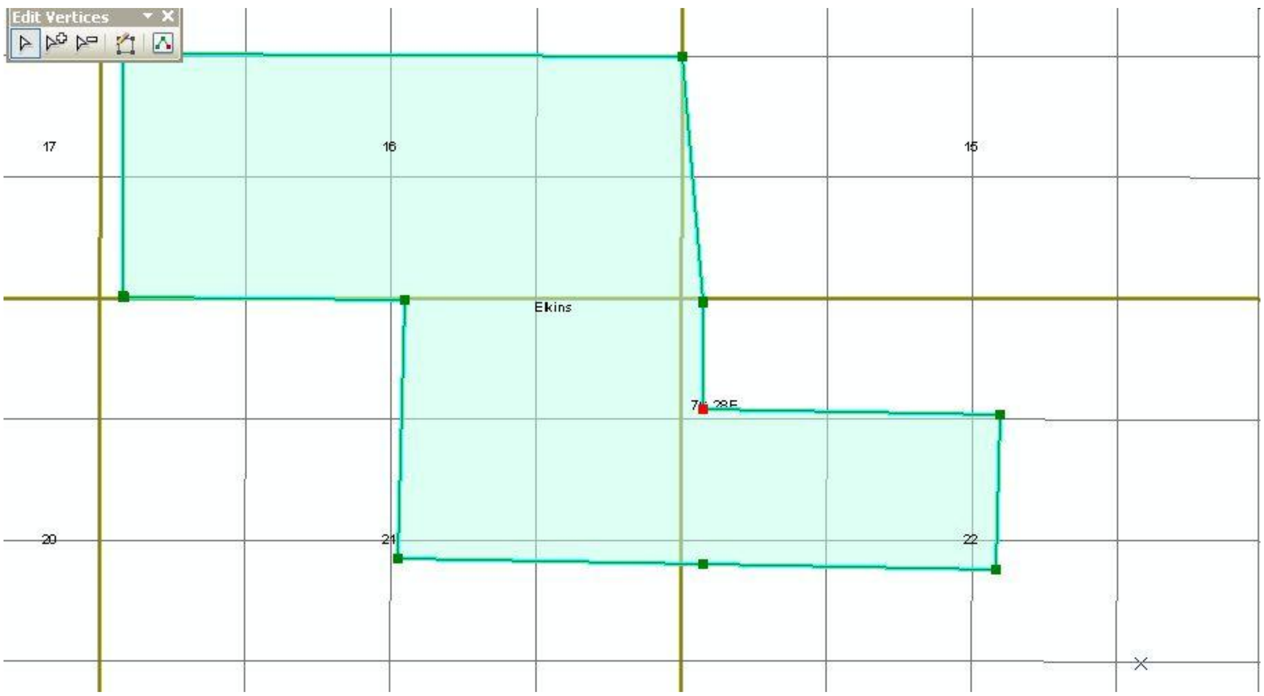


Figure 3.6. The process used to align boundaries with the land grid involved snapping polygon vertices (green square markers) to land grid vertices, adding additional vertices where needed to maintain proper alignment, removal of duplicate or unnecessary vertices, removal of dangling ends, and removal of any internal boundaries missed during the automated Dissolve process described in the text.

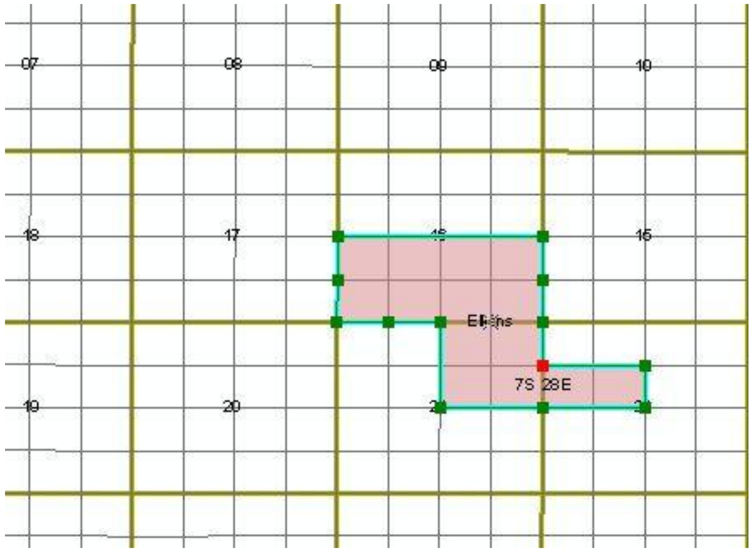


Figure 3.7. Screen shot showing edited pool boundary. All internal lines are the unit or quarter quarter boundaries of the underlying land grid.

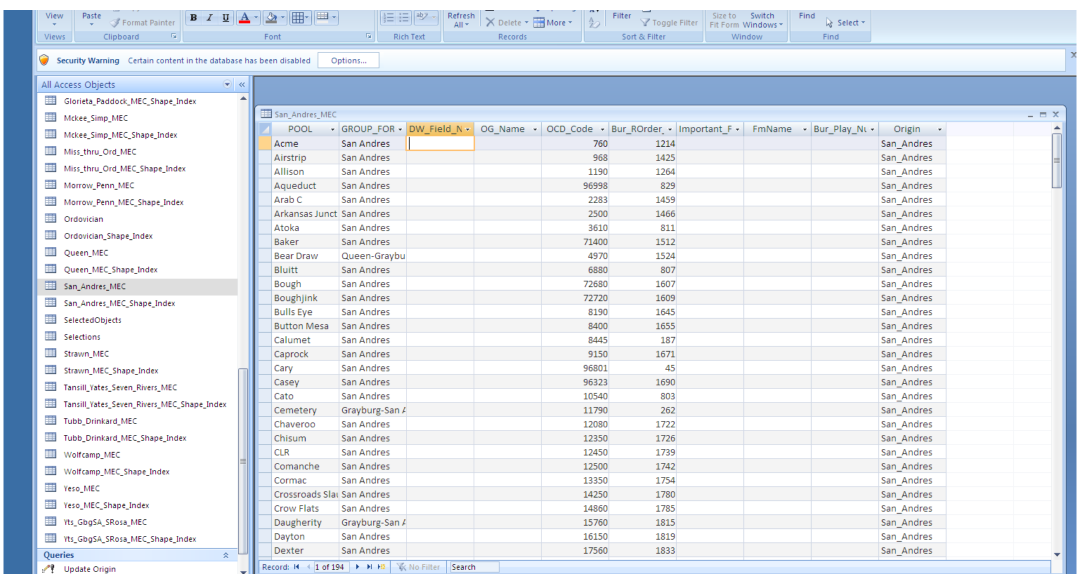


Figure 3.8. Final processing includes population of other attribute fields. In this case, the OCD Pool Code will be used to populate other fields such as an official name, field productivity, play name, etc.

3.3 Methodology

To study the various pools and plays in the area the methodology developed by Broadhead and others in 2004 was adopted. This previous study examined some 229 reservoirs in the New Mexico portion of the Permian Basin that had produced over 1 MMBO production of oil, and grouped them into 17 plays that were wholly or in part found in New Mexico (figure 3.9). Reservoirs were grouped into plays on the basis of common geologic parameters such as reservoir stratigraphy, lithology, depositional environment, and trapping mechanisms. In addition, this work collected and analyzed information for gas plays and also extended the study to include all pools within a play.

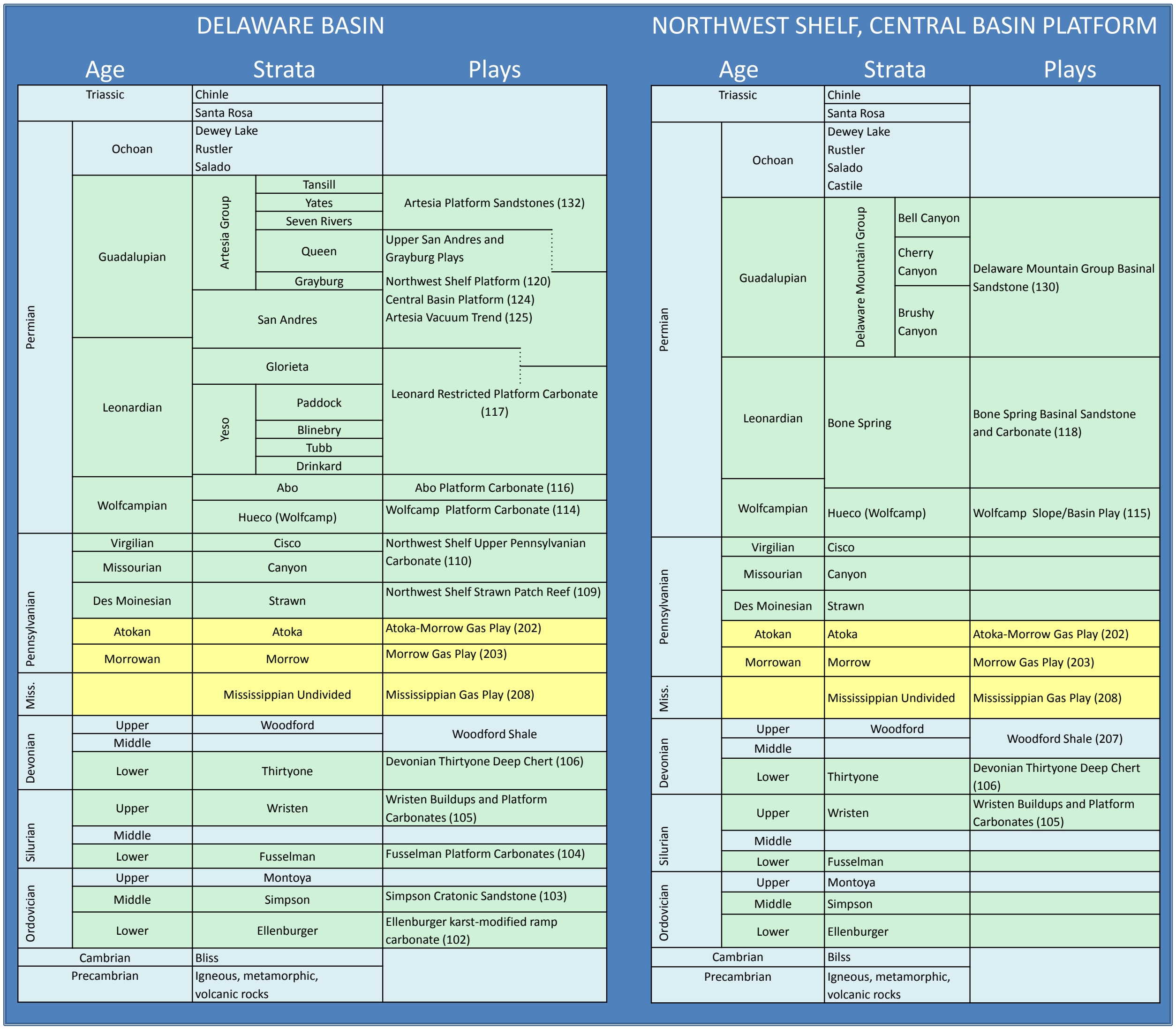


Figure 3.9. Stratigraphic columns for Southeast New Mexico

A workflow was developed to correlate the various pools and plays between the previous work by Broadhead,et al, 2004 and the New Mexico production databased from Dwights and digitized pre-1970s data. The goal was to determine where the initial play framework developed by Broadhead was sufficient, and what areas would need to be expanded.

Procedure:

1) Select a play from the geological framework developed by Broadhead (2004).
2) Query the GO-TECH database for relevant pool names. For example, one play is the Northwest Shelf Strawn Patch Reef play. A typical database query would use “pool name like Strawn” as a query. Some patch reef reservoirs are given the more generic formation designation of upper Penn, so that would be a second search. Using these options, a list of 173 different pool names containing Strawn, Strawn-Atoka, or upper Penn. is generated.

3) From this list, we then correlate the pool names in Broadhead's list to our pool name database, assigning pools to plays where possible.
4) Following this exercise, statistical analysis on the results was used to assess the next step of work.

From the statistical analysis, several things are apparent. The original work needs to be expanded to include:

a) Gas plays. Some plays are almost exclusively gas plays and the formations in the pools are primarily gas-bearing. Formations with no significant oil production in the Permian Basin were not included in any play previously described by Broadhead (2004). Because the first attempt at correlating plays w/pool names used the formation name contained within the pool name as part of the query, some pools were not included in any of the plays. The most obvious formations to include in this category are Atoka (also Atoka-Morrow) w/929 listed completions, Mississippian w/78 completions, and Morrow, w/2699 completions. Foor Ranch Pre-Permian also has a significant count of wells (126),

b) Pools that are listed as "Undesignated". There are a number of pool names that are similar to the form "Lea Undesignated; Group 5". Without knowing more about the wells in these pools, there is no way to easily assign them to a play. There are about 60 or so of these wells, so their importance is minor.

c) Smaller fields. Only reservoirs with more than 1 MMBO cumulative production were included in the previous study. A recent discovery may have < 1 MMBO but have significant future potential.

A similar basic set of data was collected for each play. Information includes basic statistics on geology, history, production, pertinent regulations, locations and technologies. Data was collected for all the plays and the important pools. Following data collection, we analyzed various reservoir parameters to create a variety of statistics on reservoir production and technological development. The final step of each play analysis was to create a prediction of the future potential of each play.

For major existing plays the goal is to analyze the information by observing past production and activity trends, and then predicting future potential. Emerging plays lack the historical background to be effectively evaluated by the workflow applied for major existing plays. However, their impact on future potential will be significant and thus requires special consideration. Recent activity has focused on the Woodford shale play as an emerging play throughout the Permian Basin.

Technology Trends

One important aspect of predicting future development is examining the new trends in technology that may impact given reservoir types and a number of such changes were considered for each play. Technological trends include changes in fracing technology such as Petro-fracking® that uses a petroleum product as a base instead of water, slick-water fracing, changes in fluid type and amount, increased use of 3-D seismic surveys, horizontal drilling, downhole commingling, multi-zone completions, multiple well pads, and changes in rules that allow for down-spacing of particular fields to tap undrained areas in existing pools. Several key technologies have been identified for further investigation; e.g., horizontal drilling and completion, and quantification of residual oil zones (ROZs). Since these technologies cross-cut through various plays, their impact will be evaluated separately.

Potash Area

Certain areas require special attention due to their potential environmental impact. These areas include but are not limited to: the Potash mine areas, the Carlsbad National Park, and the Wilderness areas. Extensive work has been completed by Balch, et al., 2009 on the Potash area. This work primarily focused on under-developed existing plays and resources within the Potash Area.

Industry Meetings

A series of meetings were held with industry personnel for the purpose of acquiring their perspective on future development potential based on current reservoir management practices. One roundtable discussion was held on March 9th and several one-on-one meetings also occurred in the first quarter of 2011. The overwhelming majority of discussion focused on the Bone Springs/Avalon play that is currently being developed with horizontal wells and the widespread potential for this play. Information shared by the participants illustrated the significant resource potential of the Bone Springs and Avalon sands. All concurred that horizontal wells will be necessary for this development. The limitations discussed were the rig and personnel availability and the current restriction in oil transportation. The Wolfcamp oil play also received some attention. Again, it is believed horizontal wells will be important to develop this play as well. The results of these meetings will assist in the predicted development we are currently assembling.

4 Discussion and Results

4.1 Summary of Play Analysis

A summary of the various plays is in Table 4.1. Each play is separated into its dominant fluid type: gas or oil or both if the dominant fluid type varies. Also shown is an estimation of the potential for future development in each play, and comments related to this potential. The scale applied for determining the potential was: Low: < 25, Moderate: 25 to 50, High: 50 to 100, and Very High: > 100 new wells per year. Details for each play can be found in the appendix.

The **highest** potential is in the currently active oil plays of the Bone Spring and Leonard-Yeso. Due to recent successful horizontal drilling in the Bone Spring, an inventory of available locations exists to be developed. The availability of drilling locations coupled with predicted stable oil prices results in a very high potential for development. In the case of the Yeso play, the advances in stimulation technology have resulted in infill drilling potential to be developed.

Play		Potential	Comments
Abo Shelf Sand	GAS	Low	Infill available, no gas price
Abo Platform Carbonate	OIL	High	Additional development, horizontal, waterflooding, EOR
Artesia Sandstone Group	OIL/GAS	Moderate	Mature, shallow targets
Atoka & Atoka-Morrow	GAS	Low	Infill available, no gas price
Bone Spring	OIL	Very high	Development of sands and Avalon, horizontal wells
Delaware Mountain Group	OIL	High	Development, waterflooding, EOR
Ellenburger	OIL	Low	Limited resource, mature, deep
Fusselman	OIL	Low	Limited resource, mature, deep
Leonard	OIL	Very high	Infill and extension drilling of Yeso
Mississippian	GAS	Low	No gas price
Penn – NW shelf	OIL/GAS	Low	Limited extent, mostly gas play
Morrow	GAS	Low	Infill available, no gas price
Penn – Strawn patch reef	OIL/GAS	Low	Limited resource
PrePermian	GAS	Low	No gas price
San Andres			
NW Shelf	OIL	Low	Mature, long term EOR-CO_2 potential
Artesia-Vacuum GB/SA	OIL	High	Mature, long term EOR-CO_2 potential
Central Basin Platform	OIL	Moderate	Mature, long term EOR-CO_2 potential
Simpson Sandstone	OIL	Low	Limited resource, mature, deep
Wolfcamp	OIL/GAS	Moderate	Additional oil development w/horizontal wells
Woodford	OIL/GAS	Low	High risk, likely re-completions in existing wells
Wristen	OIL	Low	Limited resource

Table 4.1 Summary of play analysis

High potential exists in the Abo Platform Carbonate play, Delaware Mountain Sandstone group. And the Artesia-Vacuum GB/SA play. The potential in the Abo can be separated into two areas, continued development in mature pools including the possibility of CO2-EOR; and the new horizontal development in back reef areas. The Delaware play has continued potential in development (infill and stepout) drilling with waterflood potential likely. The Artesia-Vacuum GB/SA trend will also continue development drilling, but the CO2-EOR potential is very high in this region. In all cases, oil is the primary target.

Moderate potential was identified in the Artesia sandstone group, the Central Basin platform trends of the San Andres, and the Wolfcamp. Even though very mature, the Artesia sandstone group is a widespread, shallow and predictable target. Development in this play will primarily be infill, replacement and development wells. The San Andres trends consist of large, prolific units; e.g, Vacuum, Hobbs, Maljamar, and Eunice-Monument. CO2-EOR is ongoing in several of these units, with remaining pools the top candidates for expansion into EOR. Recent success of horizontal wells in the Wolfcamp for oil; lead to the prediction of continued development.

The remaining plays listed have **low** potential either due to being gas-prone, mature and depleted, or limited resource.

An overall potential map for Southeast New Mexico was developed and is shown in Figure 4.1. This map was generated by combining and superimposing the areas of potential for all of the plays.

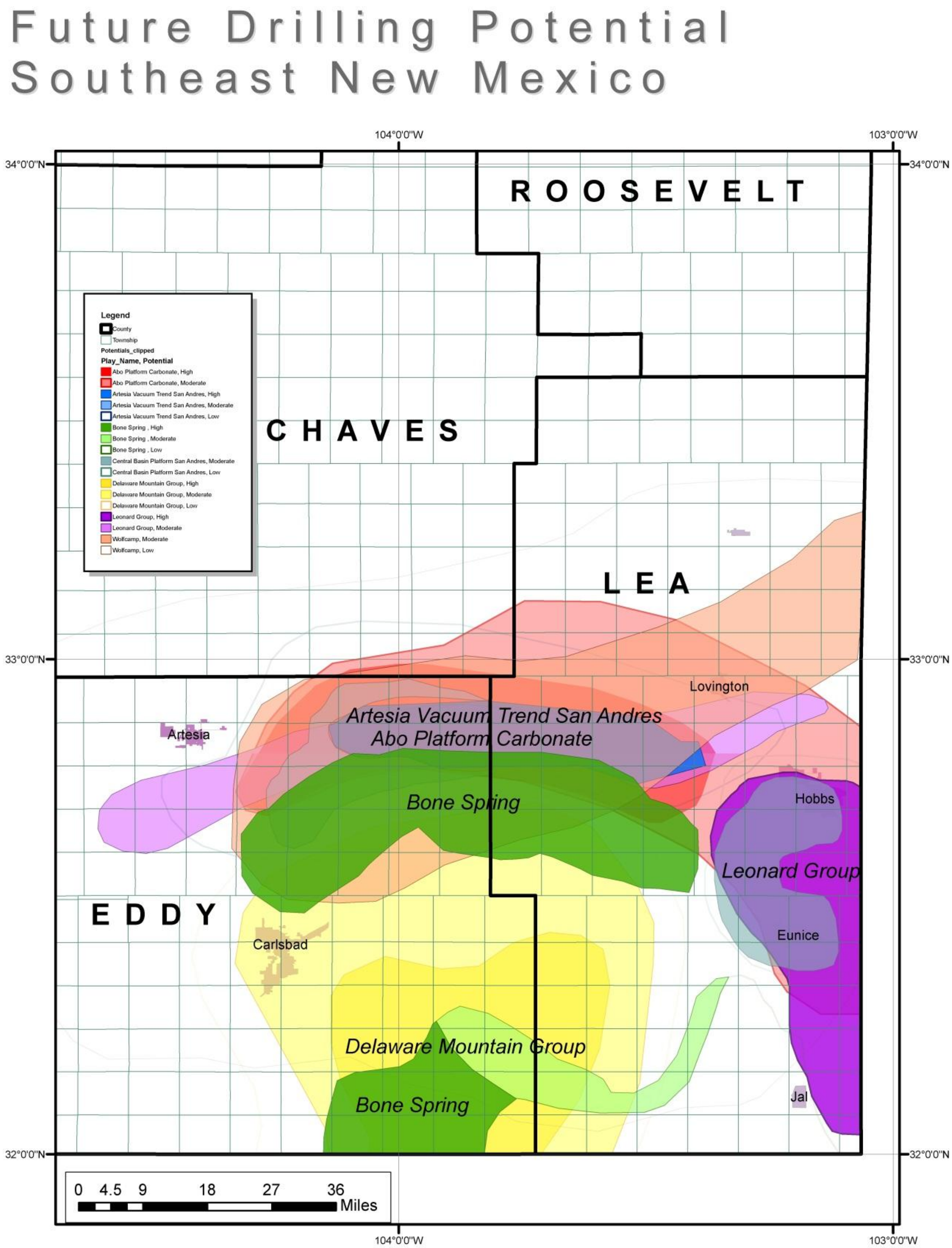


Figure 4.1 Potential map for all plays in Southeast New Mexico

4.2 Potential for CO2 tertiary recovery

A report by ARI (2006) provides a comprehensive evaluation of the future EOR potential in the large oil fields of the Permian Basin and the barriers that stand in the way of realizing this potential. Multiple scenarios were considered: (1) traditional practices, (2) state-of-the-art - application of current technology to reduce the inherent risks of these complex reservoirs, (3) Risk Mitigation – economic incentives to reduce the overall cost for investment, and (4) ample supplies of CO_2.

From this study, 55 reservoirs in New Mexico were identified as containing 1.3 to 2.8 billion barrels of technically recoverable oil using Miscible CO_2-EOR. Location of these New Mexico Fields is shown in Figure 4.2, along with the existing CO2 pipelines and sources.

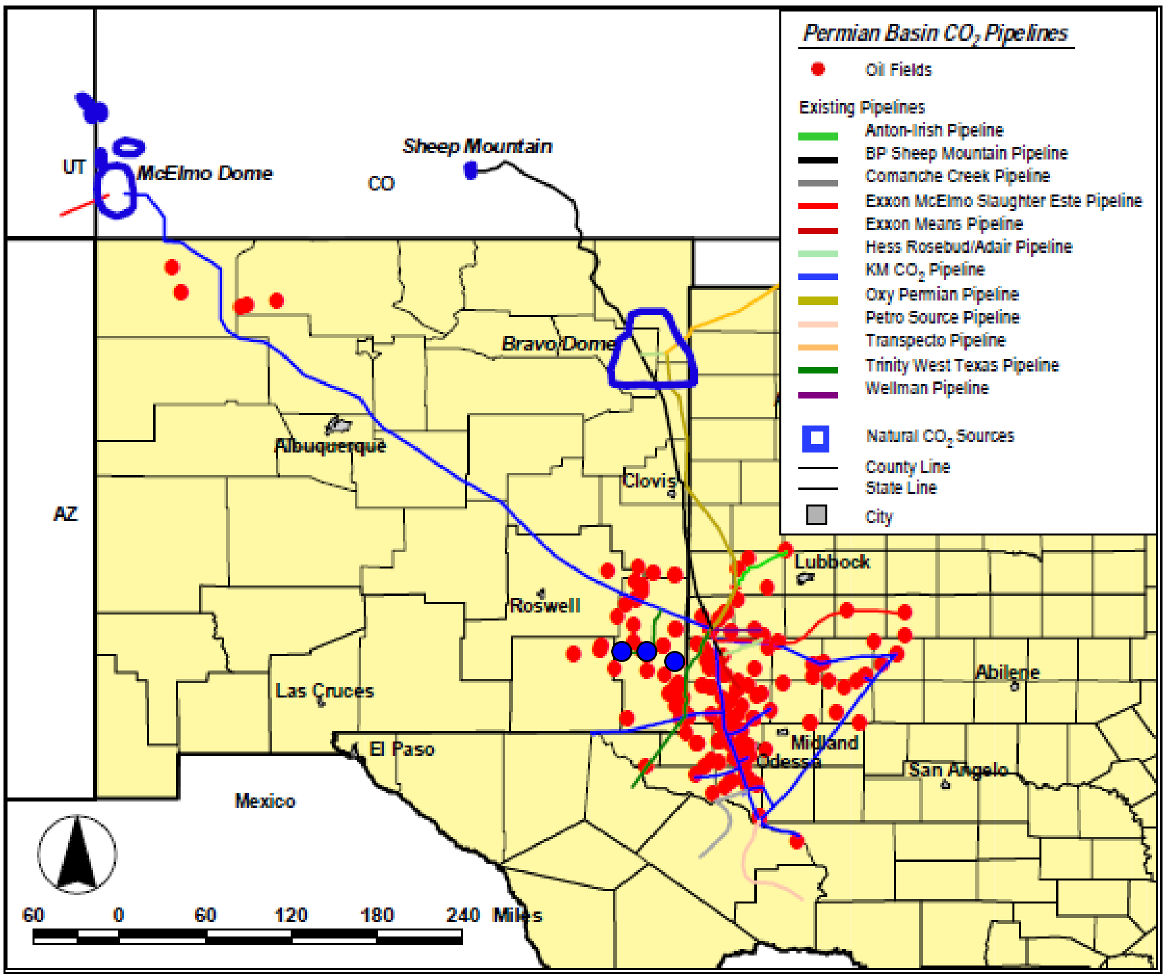


Figure 4.2. Location of Major Permian Basin and NW New Mexico Oil Fields amenable to CO2-EOR and existing CO2 pipelines and sources. Blue dots represent pools (listed in Table 4.2) which have or are currently undergoing CO2-EOR.

CO2-EOR has occurred in three major units in Southeast New Mexico; the Vacuum San Andres, Hobbs, San Andres and the Maljamar MCA GB/SA pools, with the latter no longer actively injecting CO_2(See Fig 4.2 for location). The performance of these three fields has been exceptional (Table 4.2).

Pool	OOIP	E.U.R. (primary & secondary)		Tertiary CO2 prod to date	
	MMBO	MMBO	% OOIP	MMBO	% OOIP
Vacuum SA	791	343	43	63	8.0
Hobbs SA	807	412	51	27	3.3
Maljamar MCA, GB/SA	274	99	36	10	3.6

Table 4.2 Performance of the three CO2-EOR projects in Southeast New Mexico

Based on traditional practices, 1.3 billion barrels is technically recoverable. If more favorable conditions exist (new technology, economic incentives, and/or unlimited CO_2 supplies) then the technically recoverable portion increases to 2.85 billion barrels. Eunice-Monument GB/SA field is considered to have the greatest potential; with original OIP of 2 billion barrels. Estimated ultimate recovery (primary and secondary) is 422 MMBO or 21% of the OOIP; consequently significant oil-in-place remains to be recovered.

One of the limitations of CO_2-EOR is the large volumes of CO_2 supplies required in the Permian Basin to achieve the defined CO_2-EOR potential. Additional supplies from current sources (Sheep Mountain, Brave Dome, etc) and new sources (high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and others) will need to be discovered and economically feasible for development of any additional CO_2-EOR projects in the area. Pipelines are already near capacity, as is the available CO_2. Distribution lines would also be needed. Notice in Figure 4.2, for Southeast New Mexico only three of the 55 fields are currently implementing CO_2-EOR (Vacuum San Andres, Hobbs San Andres and Maljamar Grayburg/San Andres). Lack of CO_2 distribution lines and supply has curtailed development of these resources.

Residual Oil Zones (ROZ) are formations that contain oil at saturations too low to be produced by primary production or water floods (Figure 4.3). These zones are typically the oil saturated intervals below the producing oil water contact and are thought to have been swept by natural water flooding processes. Thus CO_2 EOR may be a viable means of mobilizing a significant amount of the remaining oil in the ROZ.

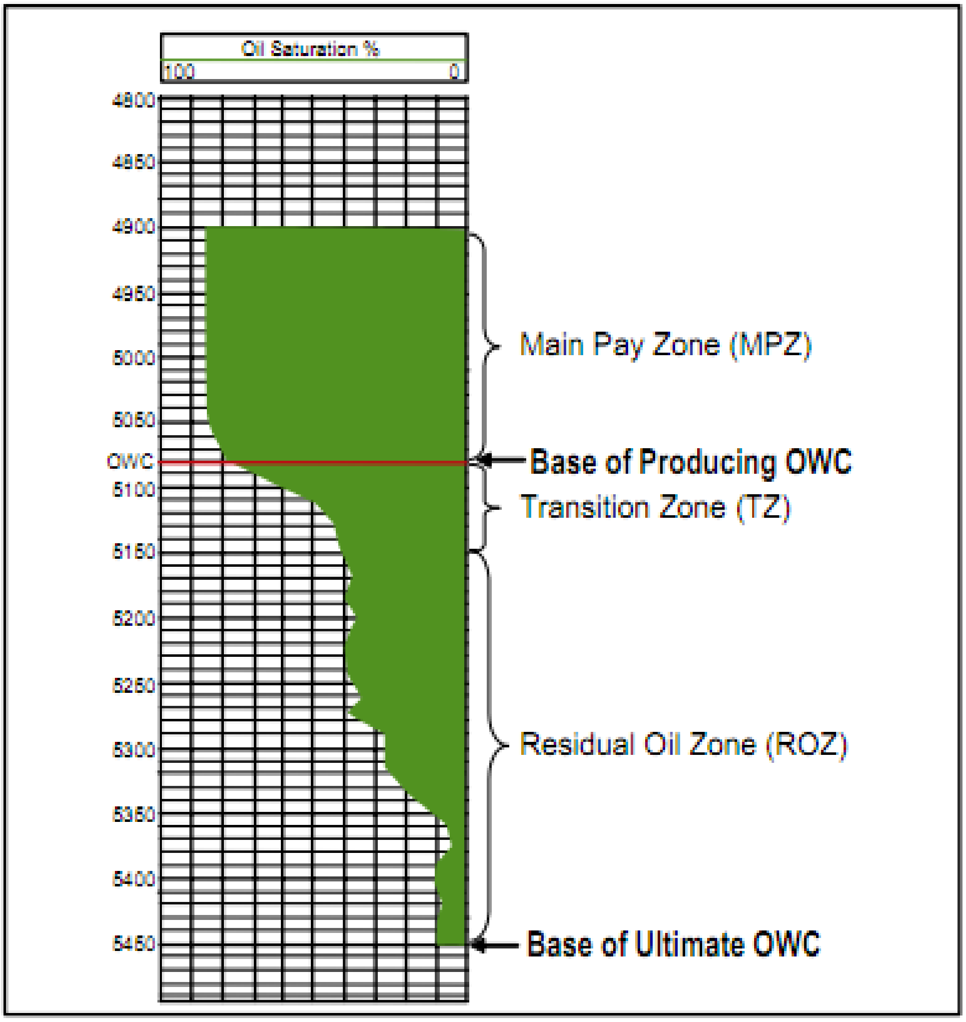


Figure 4.3 Oil Saturation Profile in the TZ/ROZ. Adopted from Melzer (2006)

Three ROZ fairways have been identified in southeast New Mexico: the Artesia, the Roswell and the Slaughter fairways (Figure 4.4). Each fairway has unique geologic and reservoir characteristics that determine the extent of ROZ development. This extent depends on the access to flush waters, formation thickness and extent of lateral continuity development from source to discharge to allow sweep.

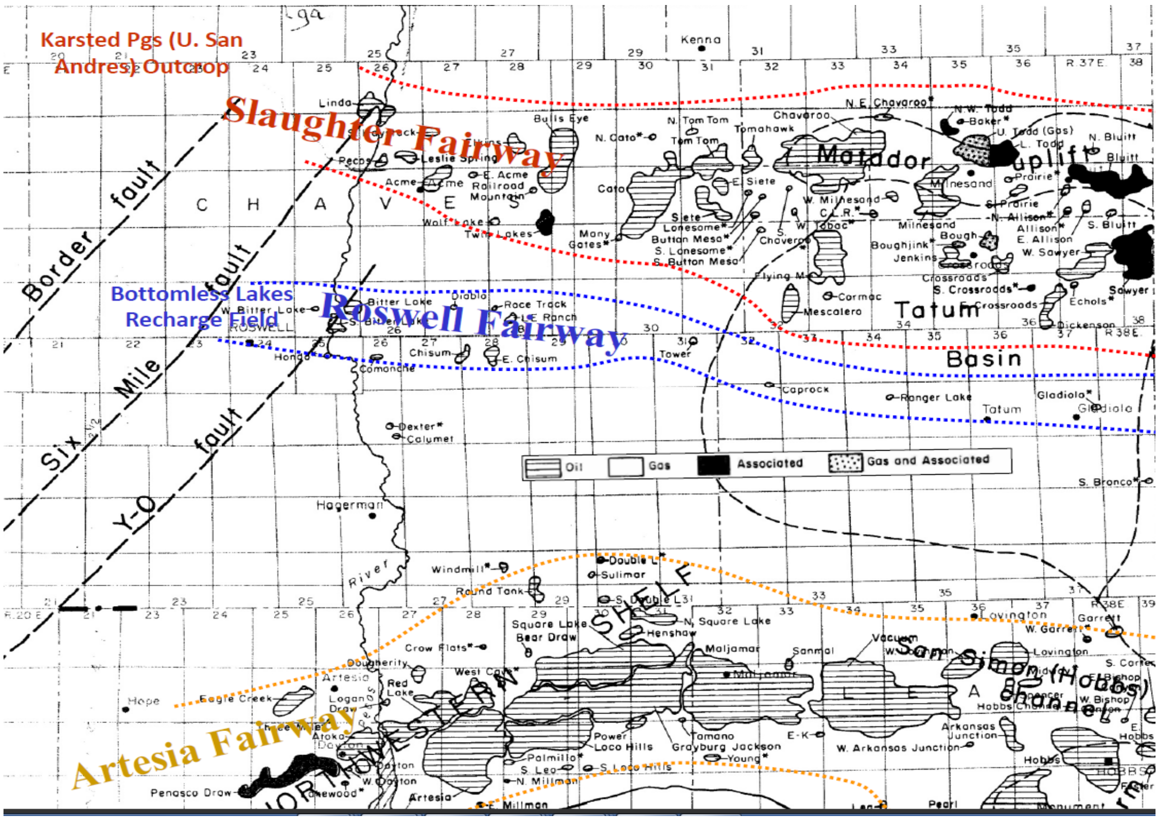


Figure 4.4 ROZ fairway map in southeast New Mexico. Adopted from Melzer (2010)

Within the Artesia trend is three major existing CO_2 floods: the Vacuum, Hobbs and Maljamar Fields. All three produce from the prolific Grayburg – San Andres carbonates of Permian age. A comparison of the reservoir characteristics and oil saturation profiles in these ROZs show a similarity to that of the main pay zone (MPZ) after it has been water flooded. As a result the oil-in-place and production response was estimated.

Examples exist of successful development of the ROZs. Wells in the Seminole San Andres Unit (SSAU) of the North Central Basin Platform were deepened to include the ROZ and MPZ and then CO2 flooded. Figure 4.5 shows the significant improvement in production form this effort. The Kelly-Snyder field SACROC) in Horseshoe Atoll complex in the Permian Basin has also seen significant incremental oil production when wells were deepened to include the TZ/ROZ and then CO2 flooded. And in New Mexico, the Vacuum (San Andres) field is currently running pilots in the ROZ to study ROZ production potential.

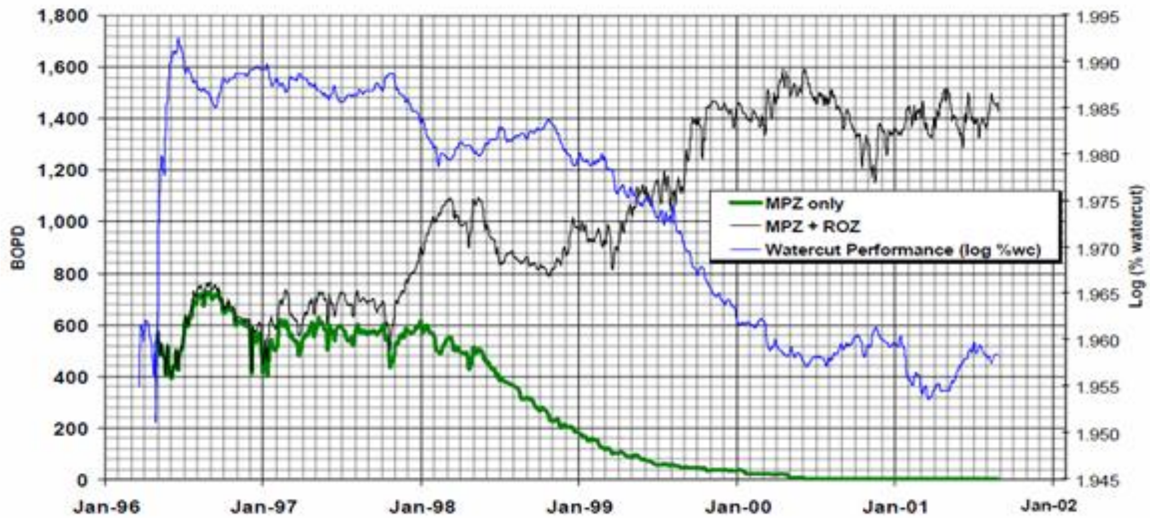


Figure 4.5 ROZ/MPZ performance in Seminole San Andres Unit(SSAU) (Adopted from Koperna, G. 2006)

A study by Nsiah (2012) was performed to assess the CO2 enhanced oil recovery potential of residual oil zones in the Permian Basin of Southeast New Mexico. A simulation model was generated using Vacuum Field data to test CO2 EOR in the ROZ. The model applied an inverted five spot injection pattern and a normal five spot pattern during tertiary recovery stage. An existing geologic description was used to construct the simulation grid and incorporate the variation in reservoir properties. A 20 year CO2 flood prediction was simulated. Several sensitivity runs were made to improve the oil recovery. Results of the studies were used to project possible reserve and production potential from residual oil zones along the respective fairways.

The results show that it possible to produce from the residual oil zone by WAG method or a continuous gas injection. However, production from this result yields low oil cuts. On average up to 20% oil is obtainable when production stabilizes. The rate of water production is dependent on the injection methods used. For example, water production for continuous gas injection was about 50% less than the WAG method for the same inverted 5-spot well pattern in ROZ zone.

Based on this study, the highest recovery factor attainable from the ROZ is was about 5%. This is rather low figure compared to tertiary recovery rates of up 12% in the main pay zone. However it represents production that would otherwise have been forfeited. Continuous gas injection showed the highest potential to produce from the ROZ. Additional water support is not necessary due to the strong water drive already present in the ROZ.

Extrapolation of the ROZ potential to the fairways, resulted in the Artesia-Vacuum trend having the highest potential, followed by the San Andres on the Central Basin Platform, the Slaughter fairway, and last the Roswell trend.

4.3 Recent Activity

Recent drilling activity can be inferred from the number of **intents** to drill filed by industry. Figures 4.6 and 4.7 show the last five years of intents separated into plays for Eddy and Lea Counties, respectively.

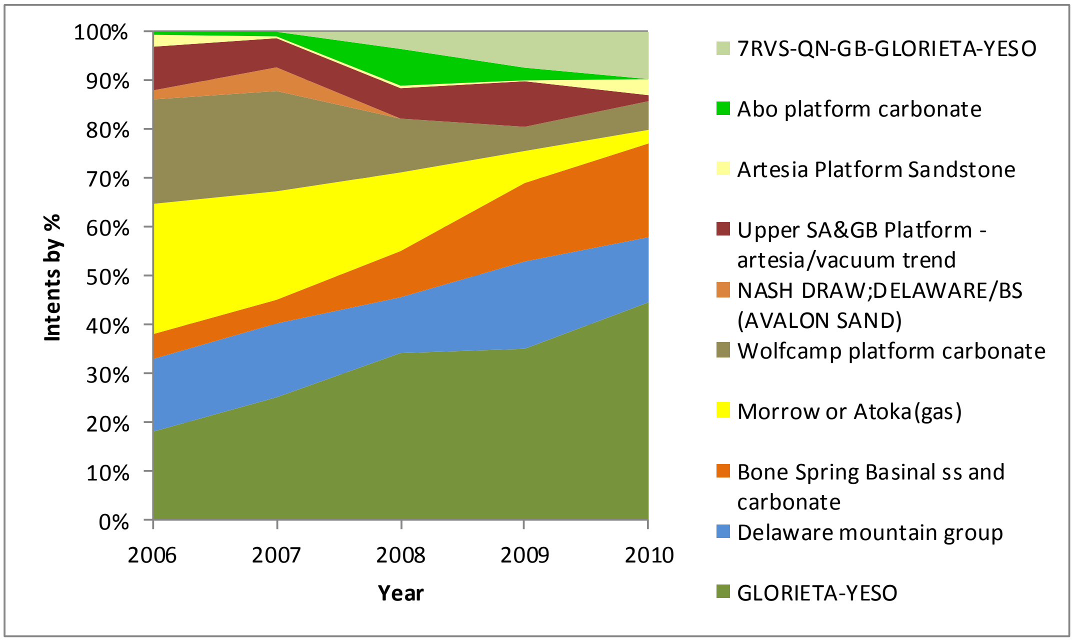


Figure 4.6 Intents to drill for the last five years in Eddy County. Legend indicates the dominant plays identified during this time.

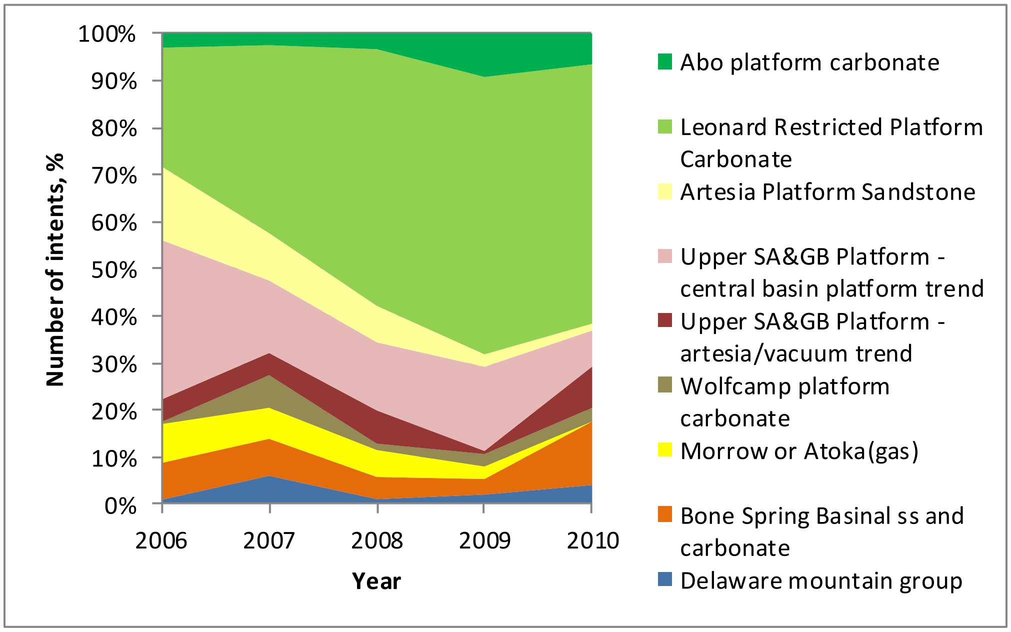


Figure 4.7. Intents to drill for the last five years in Lea County. Legend indicates the dominant plays identified during this time.

These figures reveal the top plays of interest. In Lea County, the majority of the proposed activity is in the Leonard Restricted Platform carbonate play (Blinebry, Drinkard, Tubb…). Due to the maturity of this play the activity consists of infill and extension development in existing fields.

In Eddy County, the Glorieta/Yeso and Bone Springs plays have seen an increase in interest and potential activity. The gas plays (Morrow or Atoka and Wolfcamp) have seen a decrease in the last five years.

Over the last six years drilling activity in southeast New Mexico has averaged 750 **new well completions** per year (Figure 4.8). Recently, Eddy County has been the dominant activity area with the development of the Avalon/Bone Springs play.

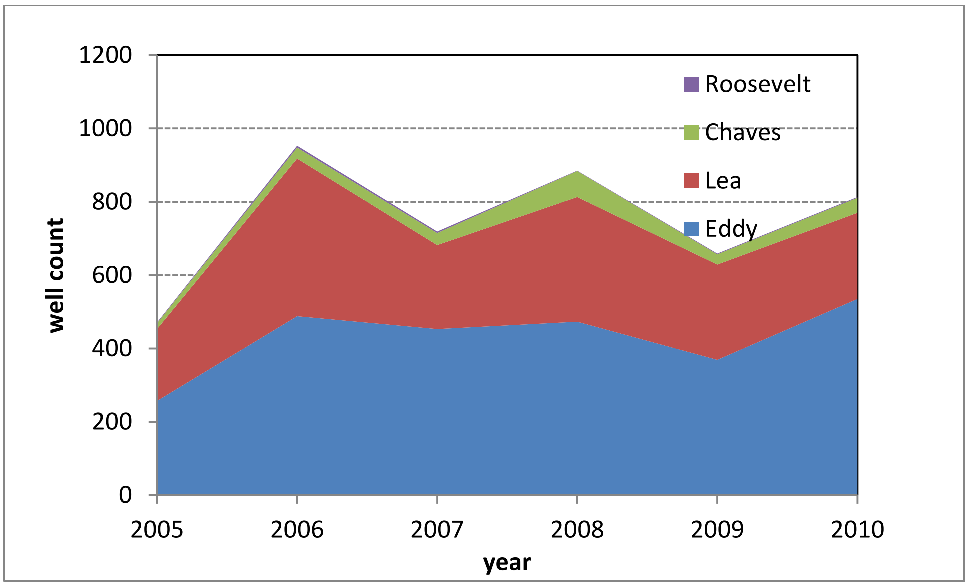


Figure 4.8. Number of new well completions per year by county. (Source: GOTECH)

Total well completions average 1200 per year for the four counties shown in Figure 4.9; with the majority of completions equally divided between Lea and Eddy Counties. Total completions (Fig. 4.9) accounts for not only new well completions but also includes re-completions, commingled zones and dual completions. We can infer from this data that 60% of all completions are for new wells drilled, or 40% of all recorded completions are dual completions, etc. As a result, re-completions, commingled zones and dual completions are a significant benefit by allowing development of resources while simultaneously reducing surface disturbance. Future opportunities for all of these completion methods should be identified and if viable pursued for development.

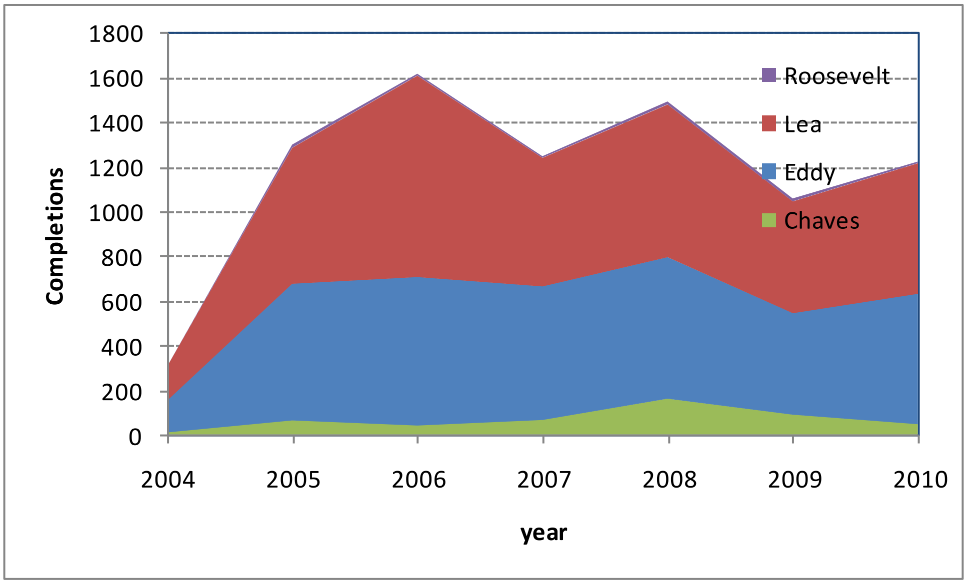


Figure 4.9. Number of total completions per year by county. (Source: GOTECH)

Spatial distribution of completions is shown in Figure 4.10. The high activity areas are easily recognizable and indicate the development of the Leonard and San Andres in Lea County and the Bone Spring and Yeso in Eddy County, respectively.

Figure 4.11 show the same completion data superimposed on a land ownership map. From 2004 through 2011, on average 40% of completions (unique drills) were drilled on lands with a federal land status. The work performed in this study was play-based using engineering and geologic information to determine future activity. As a result, throughout the study total activity is reported, regardless of land status. The 40% value is proposed to be applied to obtain an estimate for federal lands.

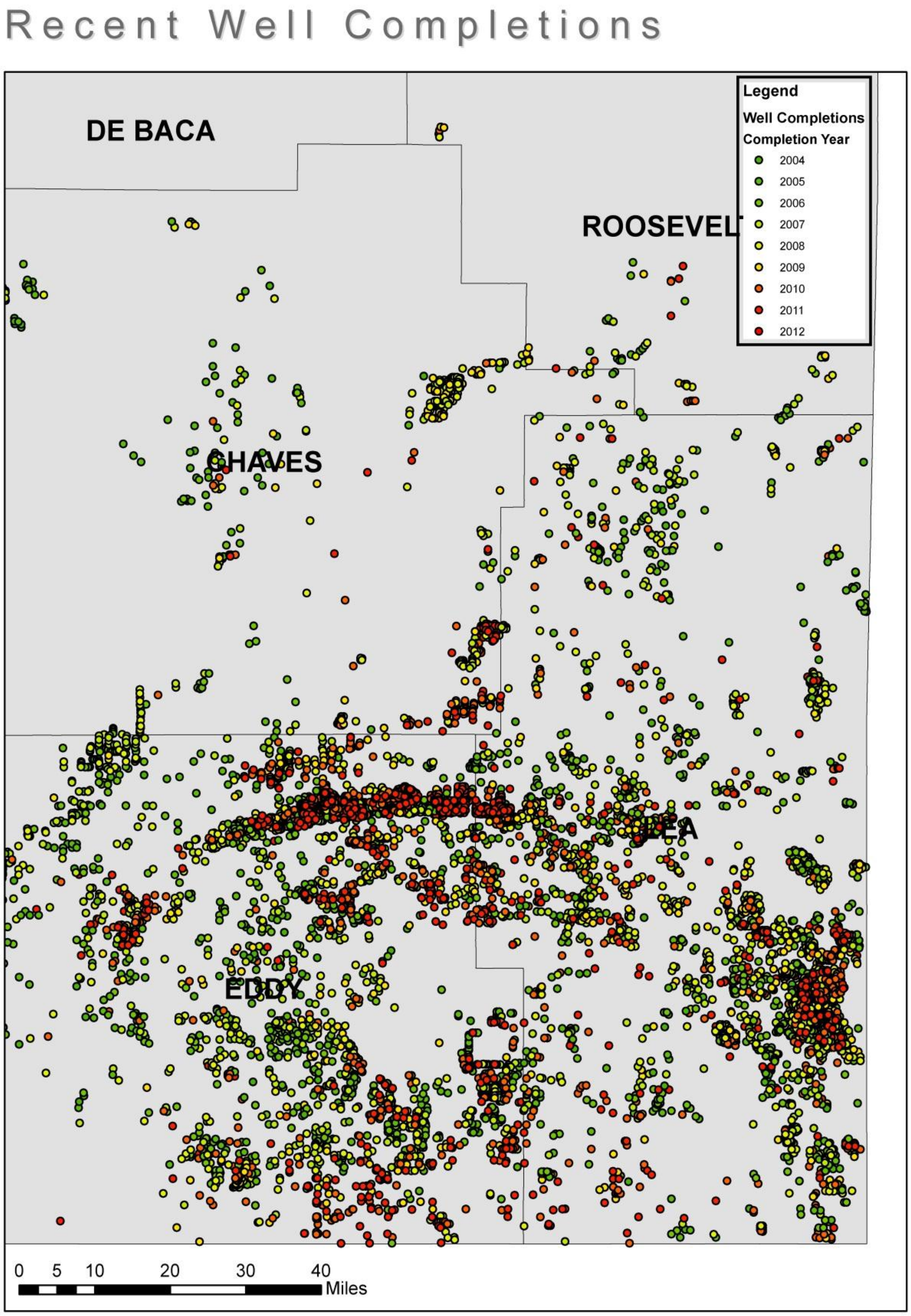


Figure 4.10 Location of well completions per year for SE NM. (Data Source: GOTECH)

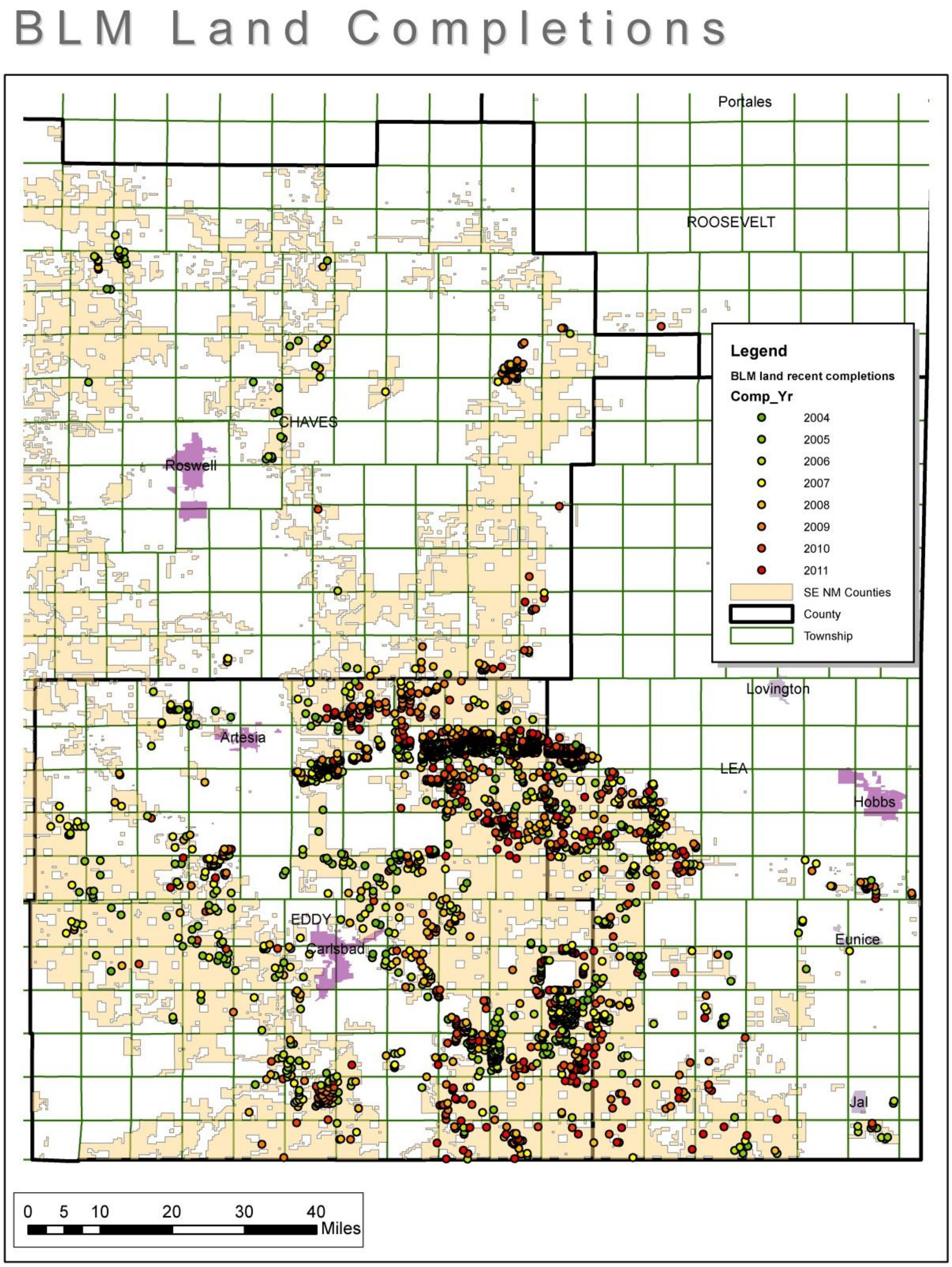


Figure 4.11 Location of well completions per year for SE NM superimposed on Federal lands. (Data Source: GOTECH)

Limitations

As activity increases external constraints delay or possibly prevent development. Potential restrictions are lack of available rigs and qualified/trained personnel, lack of water for completion or lack of disposal facilities, and lack of oil transport and/or refining capacity. As an example, Figure 4.12 provides rig count for Southeast New Mexico and oil and gas prices since the 1980s. Evident is the correlation between commodity prices and rig count, and thus development. It appears the availability of drilling rigs is flexible enough to increase when commodity price increases; reaching a maximum of 77 drill rigs in southeast New Mexico in 2005. However, the utilization rate (number of new wells/year per drilling rig) has increased to ~ 15, or slightly greater than one well per month. This ratio suggests that drill rigs are being fully utilized with no long term downtime. As a result, an operator attempting to obtain a new contract for a drill rig may have a difficult time. This limitation has been confirmed by conversations with operators, and is particularly an issue for smaller companies.

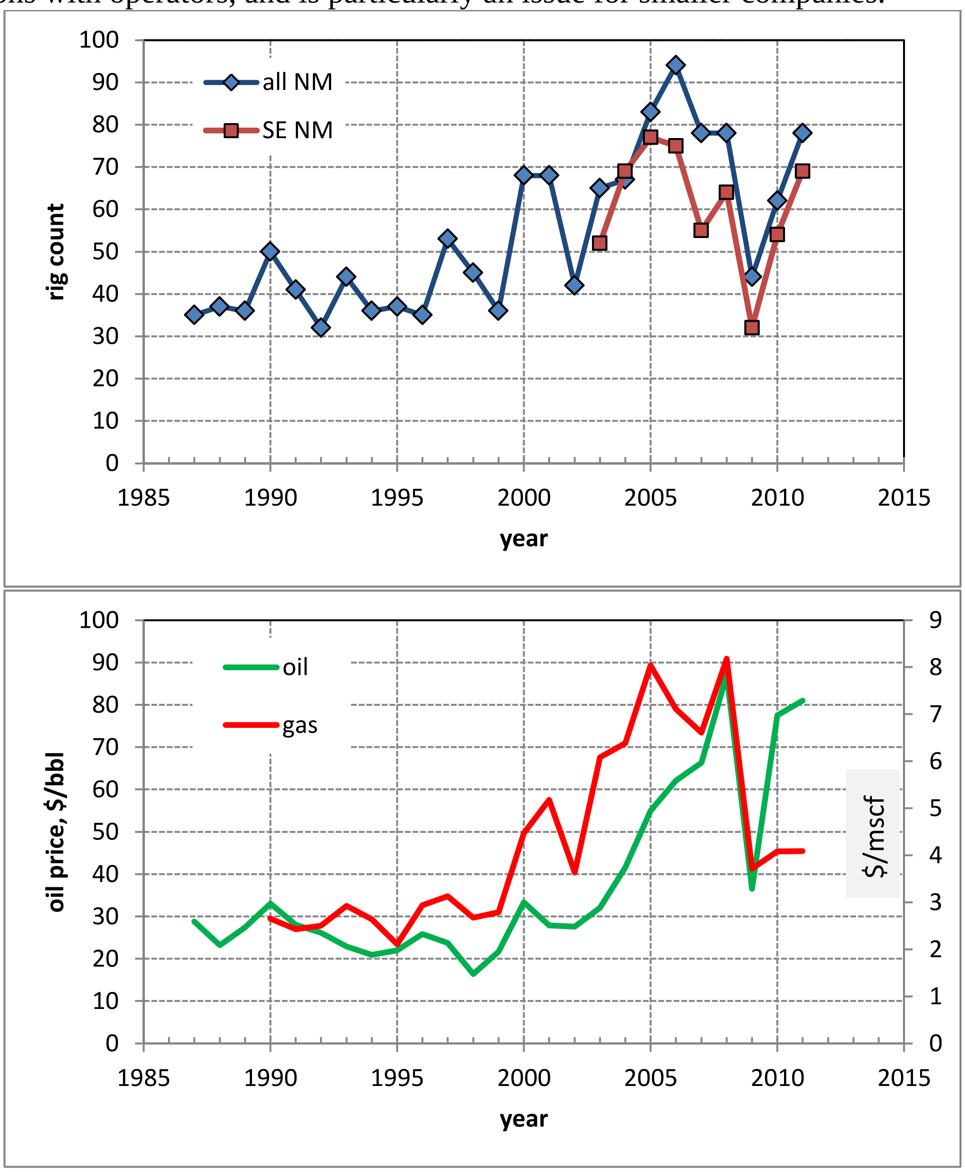


Figure 4.12. New Mexico rig count and oil/gas prices. (Source: SENM rig count from Permian Basin Oil and Gas Magazine , prices from U.S. EIA, 2011)

4.4Emerging plays

Emerging plays lack the historical background to be effectively evaluated by the workflow applied for major existing plays. However, their impact on future potential will be significant and thus requires special consideration. Recent activity has focused on the Woodford shale play as an emerging play throughout the Permian Basin. The Woodford can be characterized as a black, organic rich shale with minor black chert, siltstones, and sandstones. The Woodford Overlies the Silurian and Lower Devonian carbonates and ranges from 0 to 300ft thick in southeastern New Mexico, with a maximum thickness in South Central Lea County and pinching out to the North and northwest in Roosevelt and Chaves counties (Figure 4.13). Thermal Maturity varies throughout the region, with thermal Maturity greatest in southwestern Lea and Southeastern Eddy Counties (in the Thermogenic gas & Condensate Window) and decreasing to the north and west (in the Oil Window).

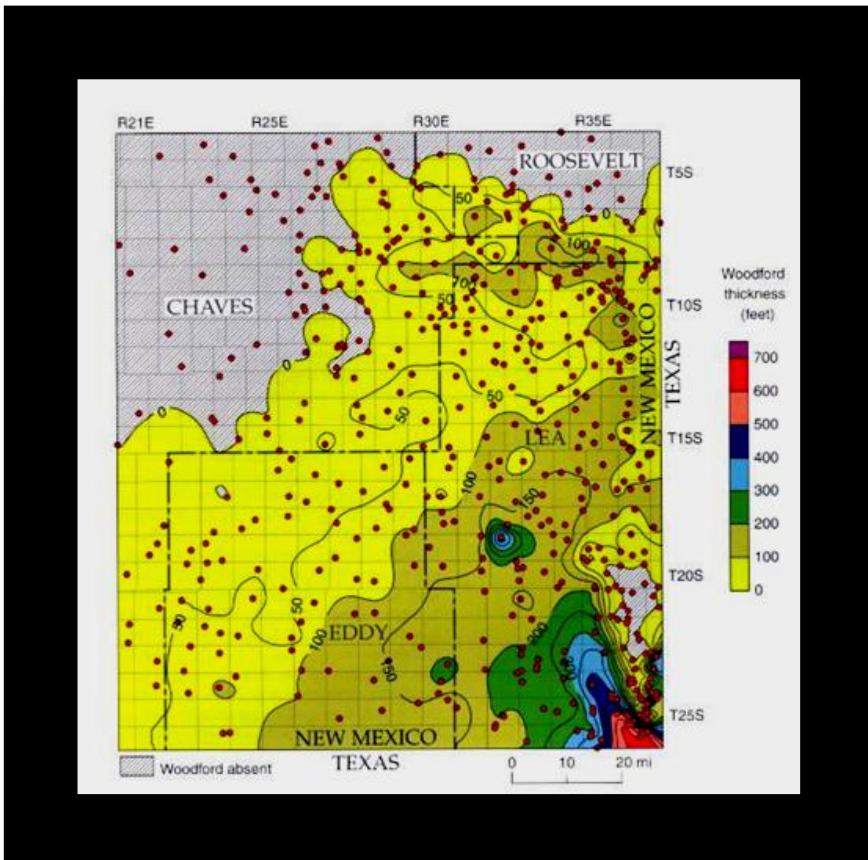


Figure 4.13. Isopach map of the Woodford shale. Gray regions indicate Woodford is absent. (Broadhead, 2010)

Potential regions in southeast New Mexico are classified based on the thermal maturity (%), TOC(wt%) and the fracture network intensity {Comer, 2005; Broadhead, 2010; Bammidi, 2011). A numerical ranking system was developed by Miller (2010) to estimate gas shale potential. The range of the scale of ranking is 0 to 100 points. The better the total points, the better are the prospects of finding shale gas. Each of the regions (Regions I, II and III) shown in Figure 4.14 were ranked for the prospects of shale gas using Miller's (2010) ranking scorecard and assigned a score of 68, 66 and 48 respectively. For reference, the Barnett score was 73 points. The results showed that Region I and II have better chances of finding shale gas. Finally an assessment was made to quantify the volumes of oil and gas in-place using Comer's (2005) Hydrogen mass balance method.

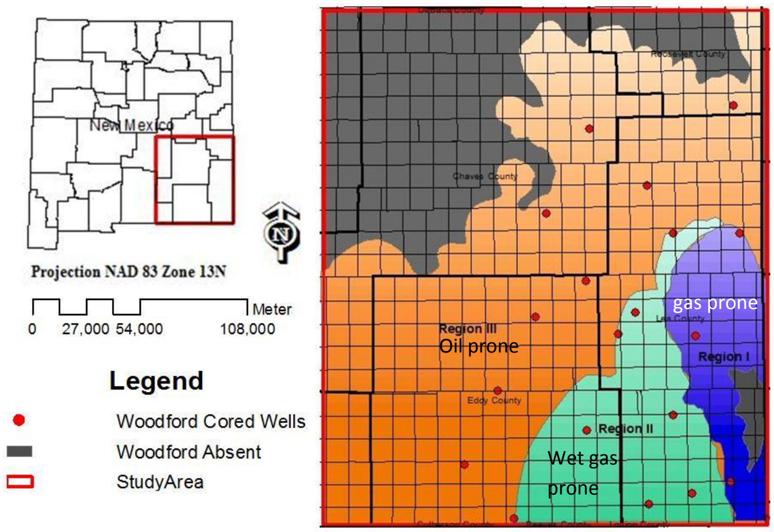


Figure 4.14. Regions used for assessment of the Woodford Shale potential in the Southeastern New Mexico. (Bammidi, et al, May 2011, updated study area using Broadhead 2010 & Comer 2005).

After a thorough analysis (Bammidi, 2011), the resource potential was determined to be low and thus the corresponding development limited. For example, assuming 4 horizontal wells per section and a recovery factor of 8%, yields for each well:

- 80Mbbls (approx) of Oil as available resource in the Green Region (High Potential Oil Region). (See Figure 4.15 for potential regions)
- 372 MMCF of Gas in the Red Region &
- 75 Mbbls of Wet Gas for the Blue Region

Resource Development under this scenario is considered a low probability of occurrence. The likely (high probability) scenario proposed is the recompletion of wells penetrating Woodford but producing from deeper targets. This option is lower initial costs and provides more information with regards to potential.

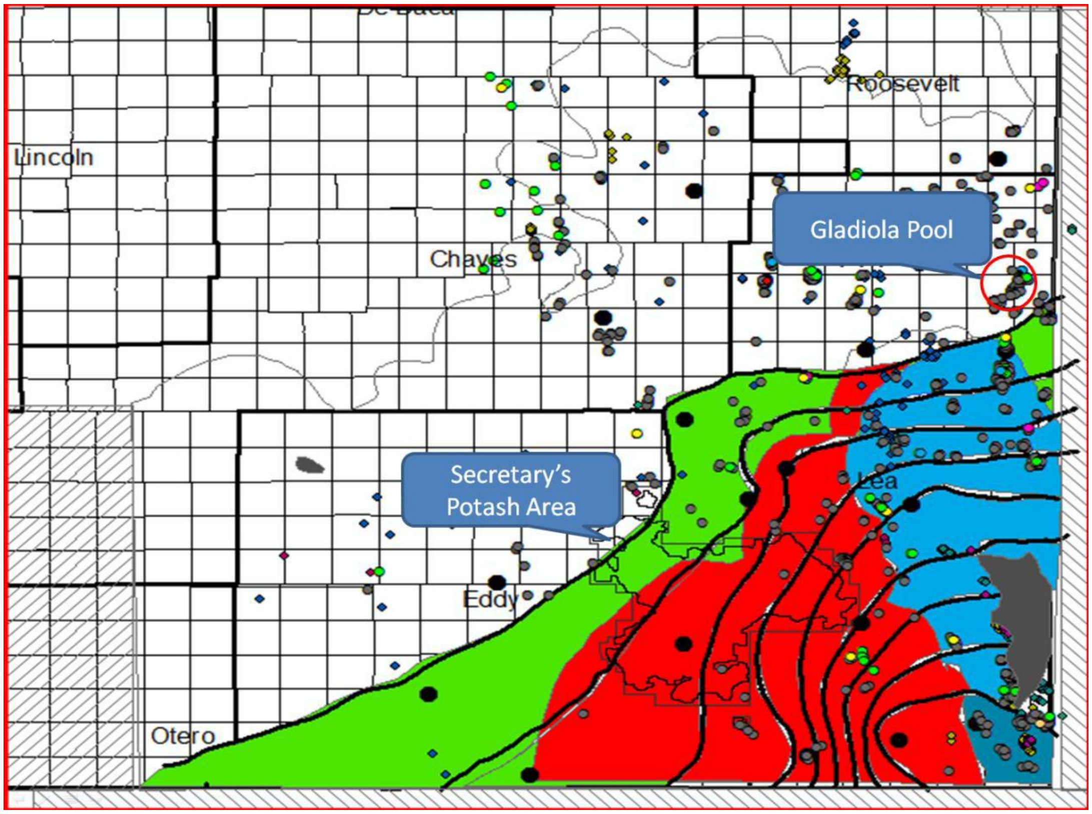


Figure 4.15. Potential regions for Oil &Gas in southeast New Mexico with black contours indicating the difference in original total organic content (TOCo) and present day total organic content (TOCpd) times the zone thickness (hwfd); e.g., [(TOCo-TOCpd)* hwfd]. The High potential oil and gas regions are derived by the [(TOCo-TOCpd)* hwfd] values greater than 50. The [(TOCo-TOCpd)*hwfd] values less than 50 are considered to be low potential for remaining hydrocarbons. Cored Wells are represented by black dots on the map.

4.5 Advanced Technology

Horizontal wells are playing an increasing role in reservoir development. Figure 4.16 illustrates the increasing trend in horizontal wells over the last ten years, from less than 10 per year to almost 180 per year in 2010. This trend is anticipated to continue in the future. In addition, technological advances will promote the drilling and completion of multi-lateral wells.

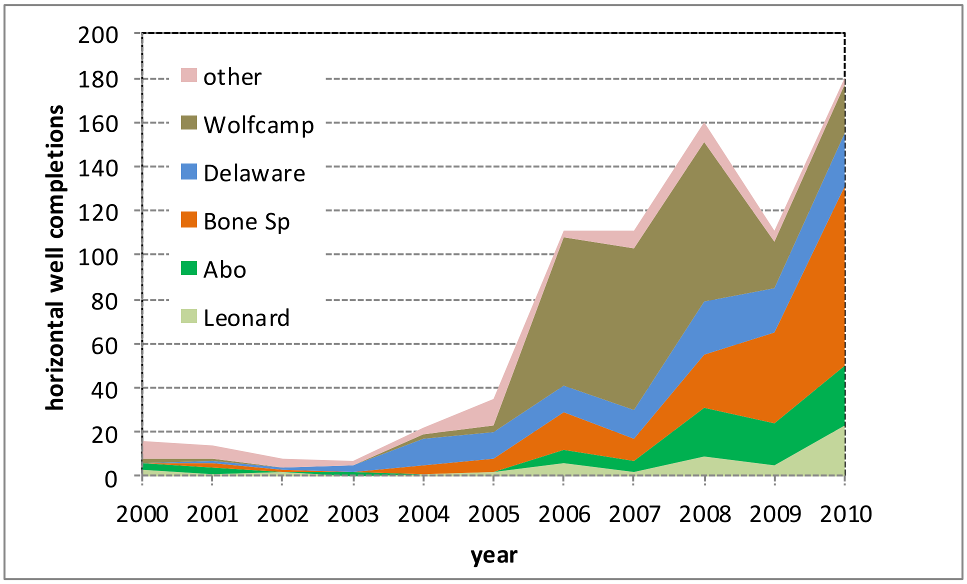


Figure 4.16 Horizontal well completions for Southeast New Mexico (Data source: Dwights)

It is evident from fig. 4.16 that interest in drilling horizontal wells is rapidly increasing; particularly in the Bone Springs play in both Lea and Eddy Counties. This activity is in response to the emerging Bone Springs/Avalon Shale/ Leonard Shale play. (Pickett, 2010) Overlooked for many years, advancements in reservoir characterization, horizontal well drilling and hydraulic fracturing have provided the stimulus for exploration and development. Encouraging early results have lead to over a half million acres leased by the industry.

Production performance for all horizontal wells in Southeast New Mexico is shown in Figure 4.17. Significant production has been observed from this development; with approximately 10 MMBO produced from horizontal wells in 2010, or ~ 27,000 bopd.

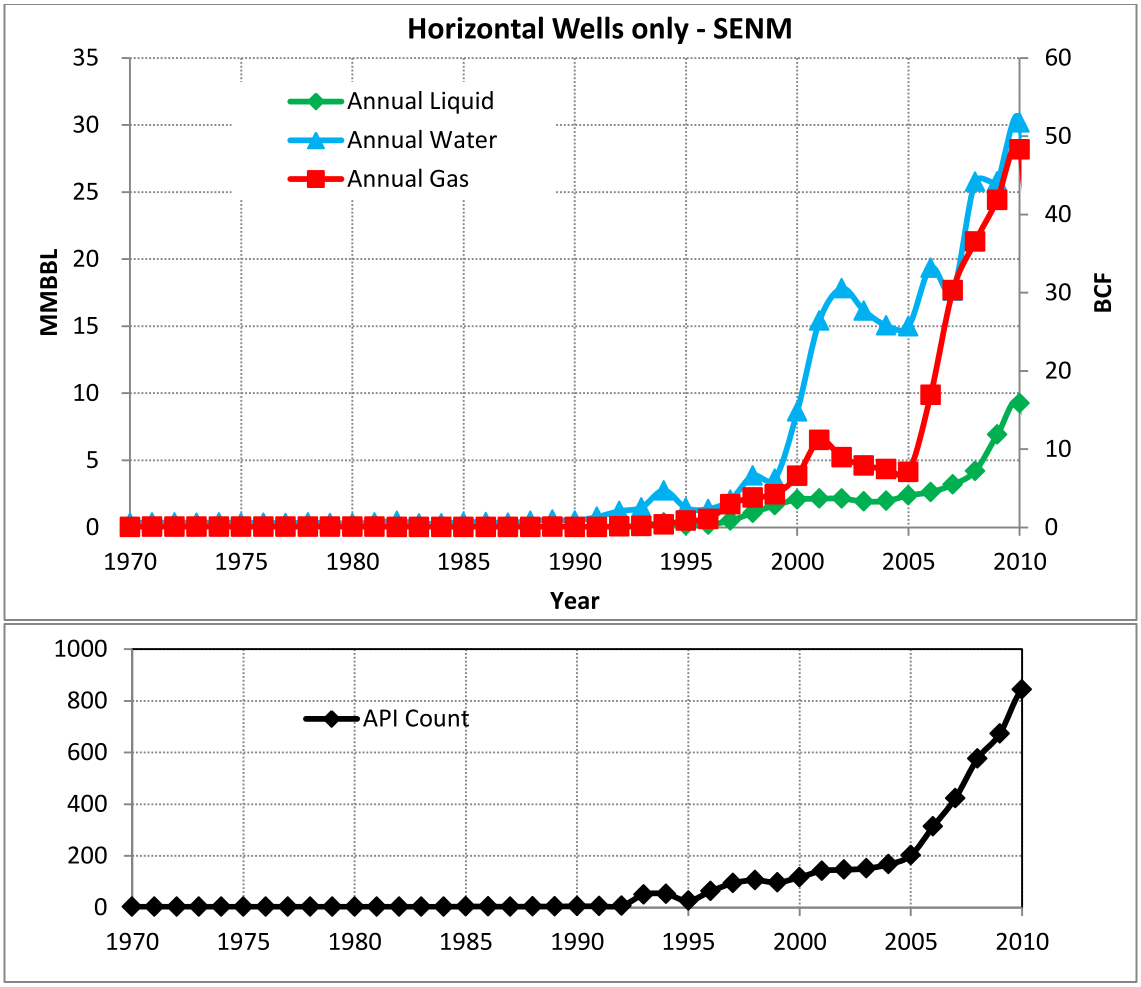


Figure 4.17 Horizontal well performance and well count for Southeast New Mexico. (Data source: Dwights)

4.6 Water Issues

Numerous pools and plays are in a very mature phase of their reservoir life; and thus are producing at significantly high water-oil ratios (WOR). In addition, several new developments are producing high volumes of fluids. An example of the former is the Vacuum (GB/SA) pools in Lea County, an example of the latter are the horizontal wells of the Bone Spring play. Increasing water production leads to the need for expanded disposal and injection facilities.

Annual water production by county is shown in Figure 4.18. In 2010, 652 MMBW were produced from Southeast New Mexico, with the majority (~70%) in Lea County. The water production trend shown in Figure 4.18 is increasing over time. This trend is anticipated to continue as pools become more mature, resulting in more waterflood and possibly CO2-EOR development.

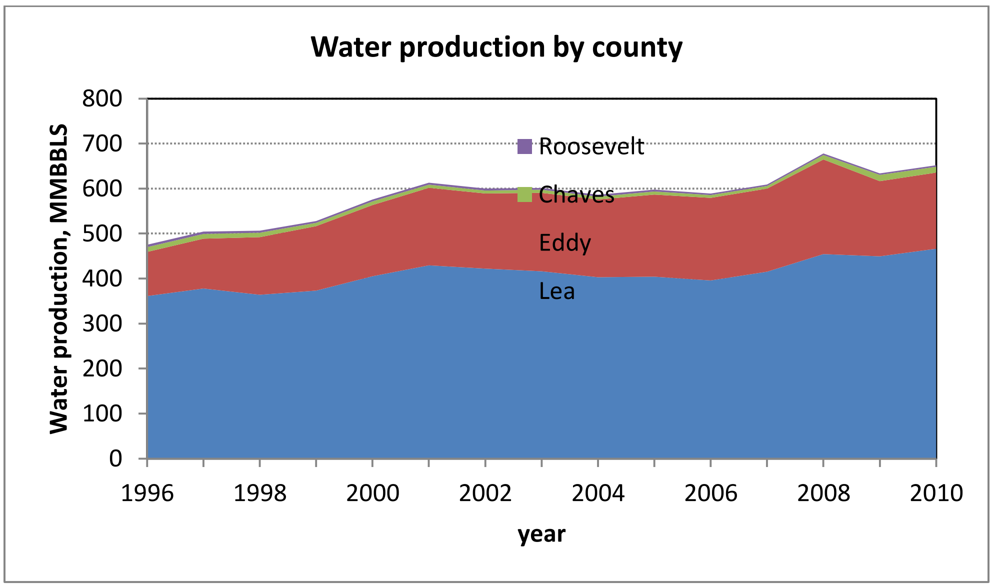


Figure 4.18 Annual water production by county. (Data source: GOTECH)

The majority of water production is from several plays as shown in Figure 4.19. The massive waterflood units in the Artesia-Vacuum and Central Basin Platform (Grayburg/San Andres) plays are the significant contributors to the water production; accounting for approximately 40% of the total water production.

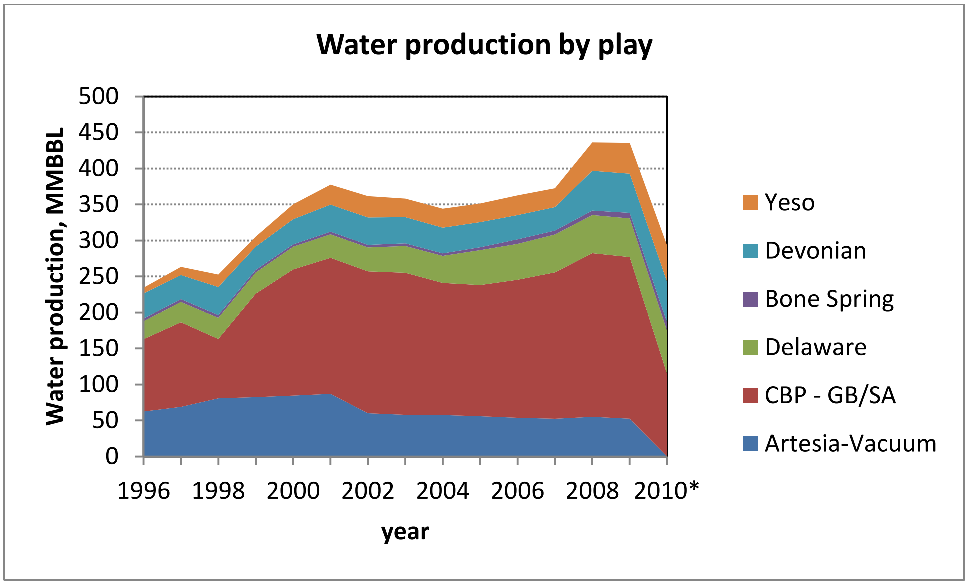


Figure 4.19 Annual water production by major play. Note: 2010 data only partial year. (Data source: GOTECH)

Corresponding to the increase in water production is an increase in water injection. Figure 4.20 shows the increasing trend by county from 1996. Infrastructure for injection and disposal of water will need to be continuously expanded and maintained to meet the demands of increasing water production.

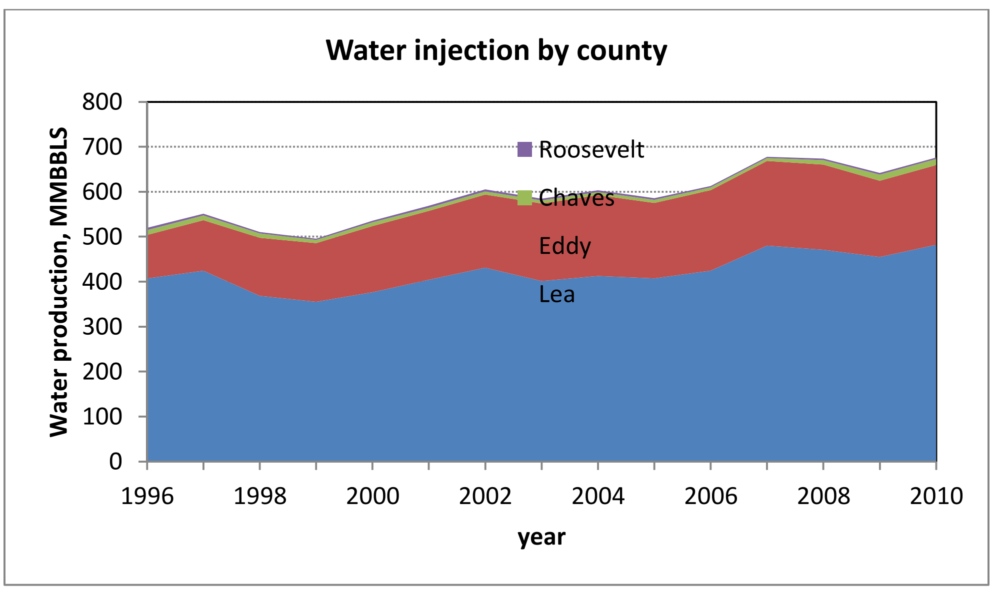


Figure 4.20 Annual water injection by county. (Data source: GOTECH)

Hydraulic fracturing requiring numerous stages in a horizontal well has resulted in significant increase in water usage; frequently in excess of 4 million gallons of water per well. This is a concern in all areas in the U. S.; but particularly in the desert southwest where water is in limited supply. Companies are responding by applying new technologies. For example, Devon is recycling water by a distillation process in the Fort Worth Basin, saving sufficient water to frac 125 Barnett Shale wells. Other include Energen which has a pilot program now under way in the Permian Basin to test the potential of recycling this water for repeat use in other frac operations, and Chesapeake which is treating and recycling produced water from its Marcellus Shale operations with the desire to expand to other U.S. operations.

The development and application of new technologies for recycling produced and/or frac water will continue to expand to meet environmental standards and to become more efficient in operations. Further analysis is beyond the scope of this work.

4.7 Surface development

All of the subsurface development mentioned above; whether infill or stepout wells, injection wells for water and/or CO_2, horizontal or vertical and disposal wells, will require access and thus additional roads to be built. Surface facilities such as tank batteries, gathering lines, etc will need to be installed and right-of-ways permitted. And last, the well locations will need to be constructed.

Standard values used in this analysis were:

Vertical well pad	- 270’ by 270’ (1.67 acres)
Horizontal well pad	- 270’ by 320’ (2 acres)
Roads	- 25 ft width
Batteries	- 2 acres

4.8 Role of Commodity prices

The current and predicted oil and gas prices have a significant impact on the future development. This is evident with the latest trend of low natural gas prices resulting in decreased gas well drilling. Figure 4.21 demonstrates the decline in activity in major gas plays with gas price.

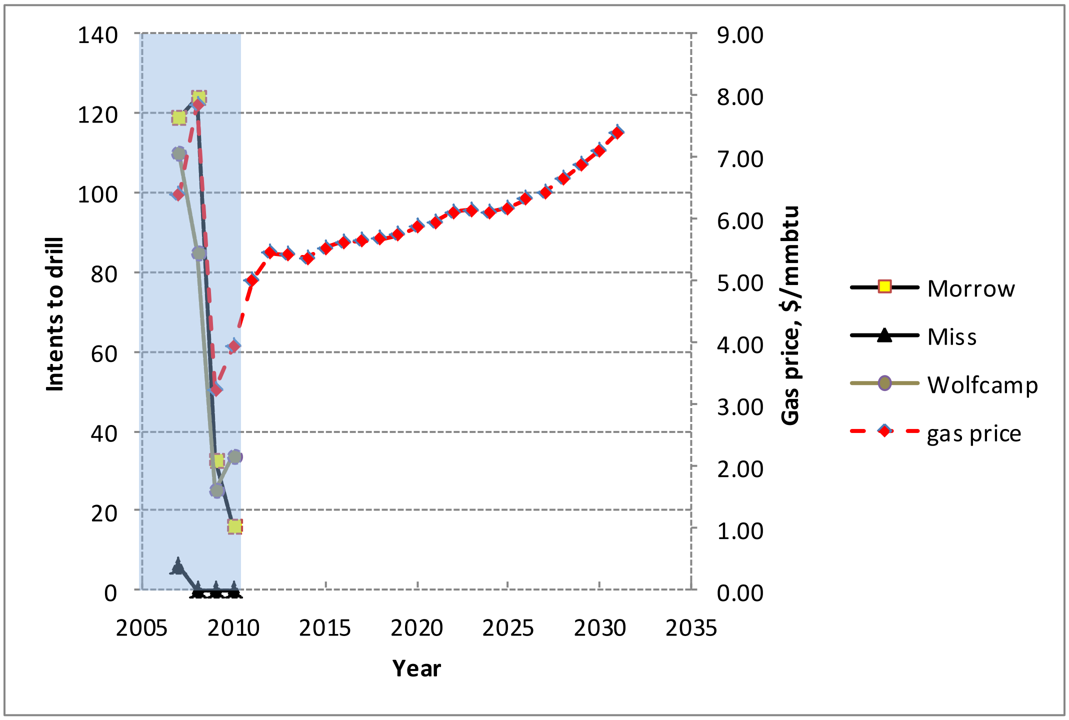


Figure 4.21 Intents to drill for major gas plays in Eddy County, NM in relation to gas price. Gas price is average lower 48 wellhead price in 2008 dollars. *Source: U.S. EIA, 2011*

Also included in Figure 4.21 is the EIA prediction of gas price for the next 20 years. With the significant supply of domestic gas from the gas shale plays, future gas prices increase modestly throughout the time period. The implication is that gas will not be the preferred target.

Another example is shown in Figure 4.22 for gas well completions since 2004 for Chaves, Eddy, Lea and Roosevelt Counties combined and the annual average wellhead gas price. With current gas prices in the $3 to 4 per mscf range, activity has been severely reduced to 65 new wells in 2010, or 15% of the high in 2006.

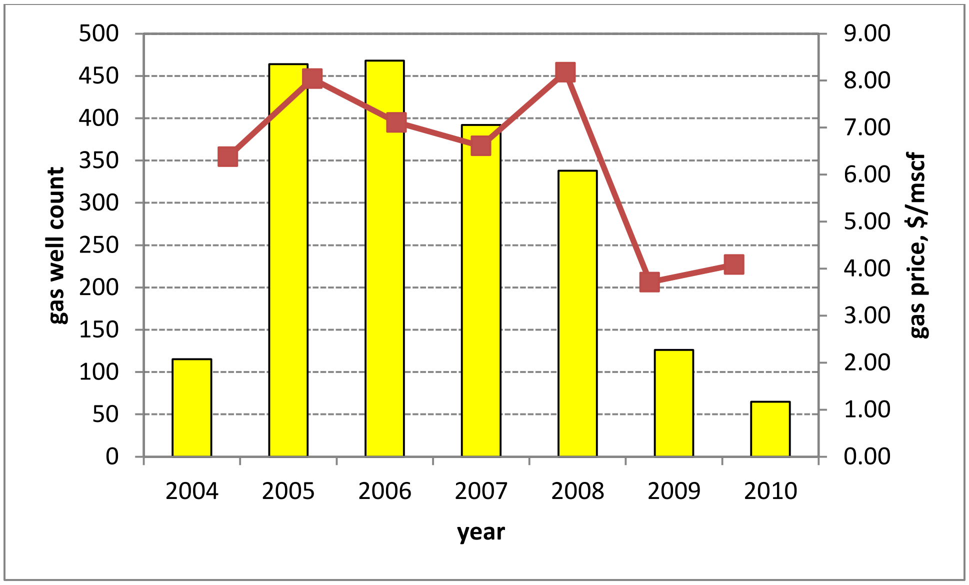


Figure 4.22 Gas well completions and annual wellhead gas price (Data source: well count from GOTECH, gas price from U.S. EIA, 2011)

EIA projections for gas are shown in Figure 4.23. For all scenarios considered, the gas prices are relatively constant for the next ten years and then only slightly increases over the next twenty years after. Consequently, gas plays are not projected to be in high demand.

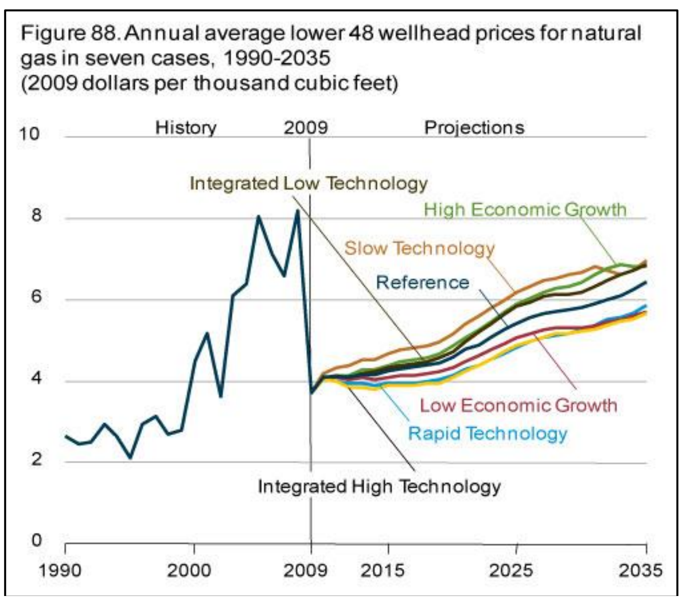


Figure 4.23. Historical and projected annual average lower 48 wellhead prices. (Source: U.S. EIA, 2011)

The opposite trend has been observed for oil. Figure 4.24 demonstrates the correlation between increasing oil price and new oil well completions.

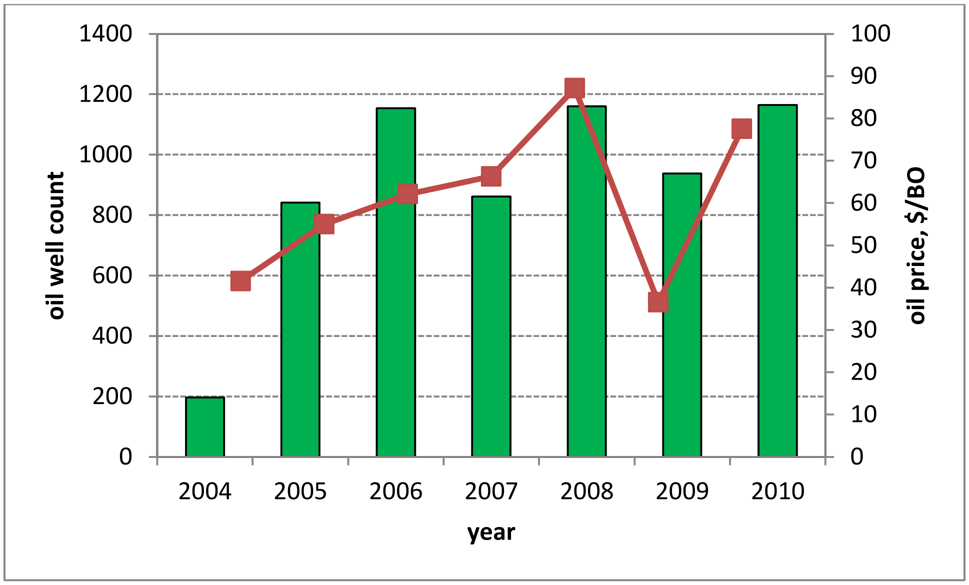


Figure 4.24 Oil well completions and annual oil price (Data source: well count from GOTECH, oil price from U.S. EIA, 2011)

The EIA projections for oil are shown in figure 4.25. Note, a wide range of oil prices are possible for the various scenarios. Using the reference case as most likely, then oil activity will continue to be important in the years to come.

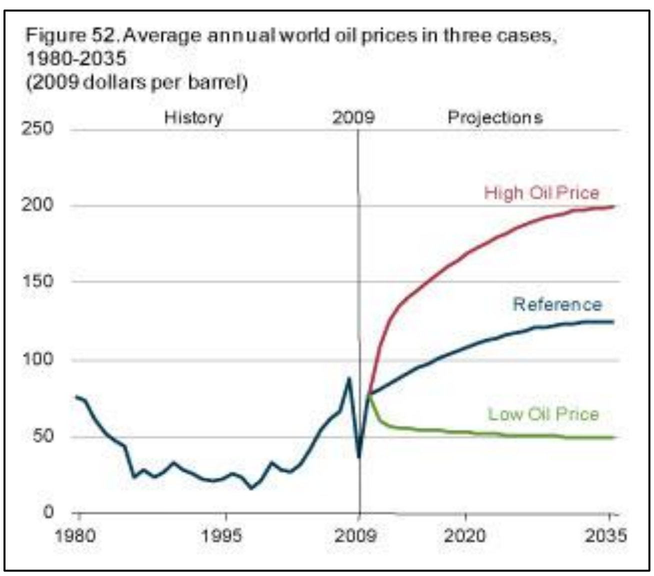


Figure 4.25. Historical and projected annual average world oil prices.
(Source: U.S. EIA, 2011)

5 Summary

1. The study area encompassed four counties in southeast New Mexico; Chaves, Eddy, Lea and Roosevelt. In play-based analysis land ownership was not considered, thereby obtaining a complete picture of the reservoir potential. As a result, throughout the study total activity is reported, regardless of land status. To acquire the Federal share, we superimposed the number of completions (unique drills) on lands with Federal status from 2004 through 2011. About 40% of wells were completed on Federal lands; thus 40% is the recommended ratio to obtain Federal share of the activity.

2. Drilling activity will continue at the current pace of ~800 new well completions per year

3. Recent activity and success in the Abo Carbonate, Yeso, Bone Springs and Delaware plays will dominate future development. The location of these high activity plays is shown in Figure 5.1.

4. Horizontal well drilling and completion will continue to see growth. Advances in stimulation have enhanced this development.

5. Depressed well head gas prices have significantly decreased the activity in gas plays. This trend is predicted to continue for the foreseeable future. Supplies from gas shales (Barnett, Haynesville, and Marcellus) and the north slope of Alaska will offset any increase in demand in the near future.

6. Variations in thermal maturity and depth results in separate oil and gas windows in the Woodford shale. The potential could be high; but the lack of confirmed production tests and interest by operators suggests this play is a long term exploratory stage. One marginal Woodford production test is known to date; thus as deeper producing wells reach abandonment, it is speculated that additional tests in the Woodford will occur. Results from tests will determine the future potential of the Woodford.

7. Produced water will increase with time as reservoirs continue to mature. The Delaware and Grayburg/San Andres plays are two of the most significant in producing water. As a result a need will exist for increased water handling, storing and disposal. Also, an increase in water injection projects is anticipated as means of disposal and potential oil recovery.

8. Residual oil zones (ROZs) are becoming of interest and are currently being tested in the Vacuum Grayburg/San Andres. If viable, ROZs will extend the life of mature oil reservoirs. However, these zones will produce significant volumes of water.

9. The potential for EOR-CO_2 is significant. Only three pools; Hobbs, Vacuum and Maljamar, all in the Grayburg/San Andres, has injected CO_2 for enhanced recovery. Other Grayburg/San Andres pools and other reservoirs are available for testing. The limiting factors are lack of CO_2 pipelines and lack of CO_2 available.

10. The need for fresh water for stimulation (hydraulic fracturing) in horizontal wells will be a serious problem for the dry southwest. An average treatment consumes 2 million gallons or 6 acre-feet of water per well.

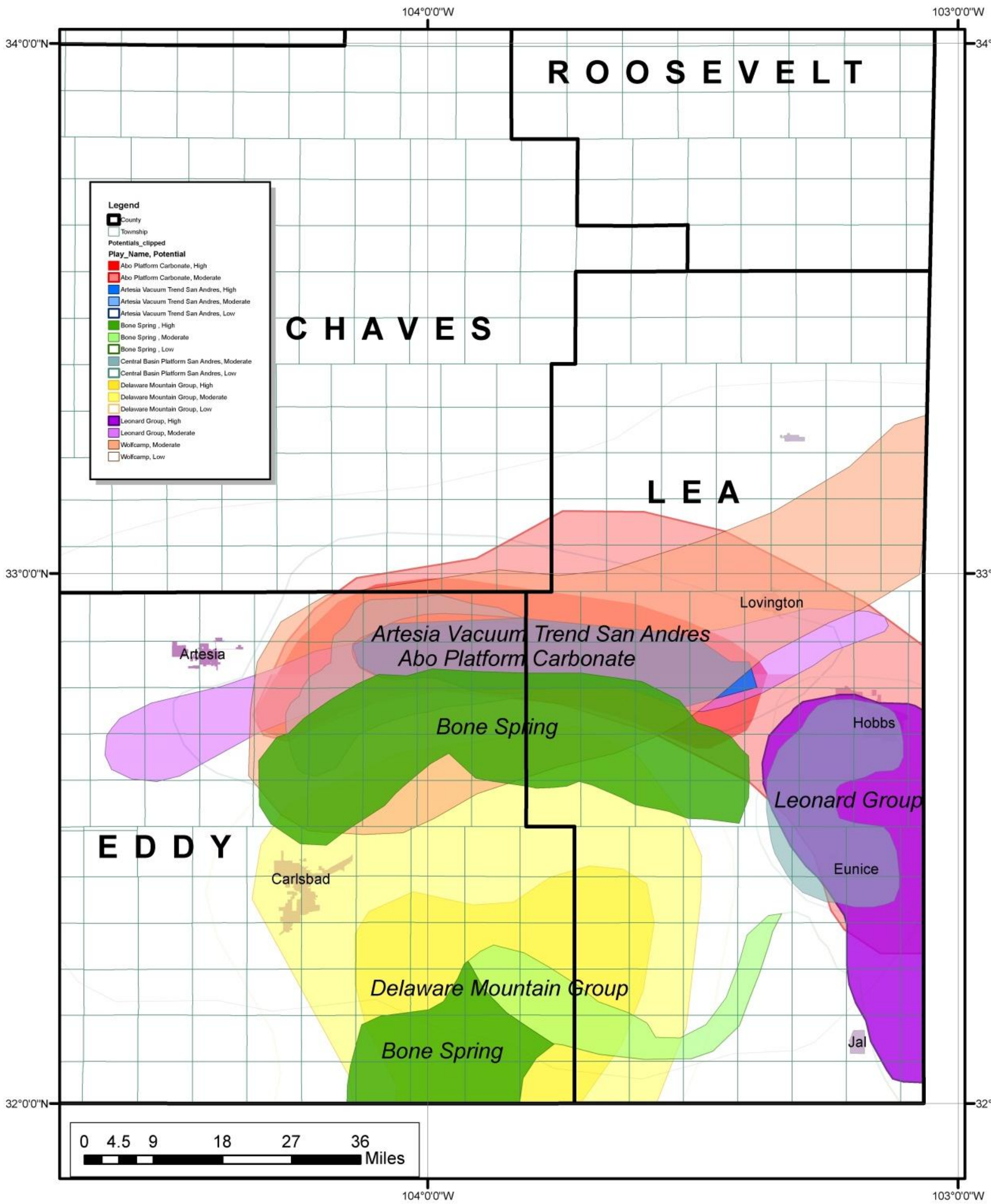


Figure 5.1 Future drilling potential for Southeast New Mexico

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LIST OF ABBREVIATIONS AND ACRONYMS

AAPG	American Association of Petroleum Geologists
BEG	Bureau of Economic Geology, Texas
BLM	U.S. Bureau of Land Management
BO	Barrels of oil
BOPD	Barrels of oil per day
BSCF or BCF	Billion standard cubic feet (gas)
CO2	Carbon Dioxide
CBP	Central Basin Platform
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EUR	Estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
ft	feet, foot
GB/SA	Grayburg/San Andres
GIS	Geographic Information System
GOR	Gas-oil Ratio, Mscf/STB
Gp	Cumulative gas production
GRI	Gas Research Institute
MBO or mstb	Thousand barrels of oil
MBOE	Thousand barrels of oil equivalent
MBBLS	Thousand barrels of liquid
MBW	Thousand barrels of water
MMSCF	Million standard cubic feet (gas)
MMBO	Million barrels of oil
MMBBLS	Million barrels of liquid
MMBW	Million barrels of water
MCFD	Thousand of cubic feet of gas per day
MBOPD	Thousand of barrels of oil per day
MPZ	Main Pay Zone
NGL	Natural gas liquids, gallons per mcf
NFS	U. S. National Forest Service
NMBGMR	New Mexico Bureau of Geology and Mineral Resources
NMIMT	New Mexico Institute of Mining and Technology (New Mexico Tech)
NMOCD	New Mexico Oil Conservation Division
OOIP	Original Oil in Place, stbs
P&A	plugged and abandoned
PRRC	New Mexico Petroleum Recovery Research Center

psi	pounds per square inch (pressure)
RFD	Reasonable Forseeable Development
RMP	Resource Management Plan
ROW	Right-of-way
ROZ	Residual Oil Zone
SENM	South East New Mexico
SPE	Society of Petroleum Engineers
Tscf	Trillion standard cubic feet of gas
TOC	Total organic carbon
TOCo	original total organic content
TOCpd	present day total organic content
TZ	Transition Zone
U.S.	United States of America
WAG	Water-alternating-Gas
WOR	Water-oil ratio, bbl/bbl

Summary

The Permian Basin is a major producing basin located in the western part of Texas and the southeastern part of New Mexico (Figure 1). It reaches from just south of Lubbock, Texas, to just south of Midland and Odessa, extending westward into the southeastern part of the adjacent state of New Mexico. It is so named because it has one of the world's thickest deposits of Permian-age rocks. The greater Permian Basin is comprised of several geologic components: the Midland and Delaware Basins, the Northwest and Northern Shelf, and the Central Basin Platform.

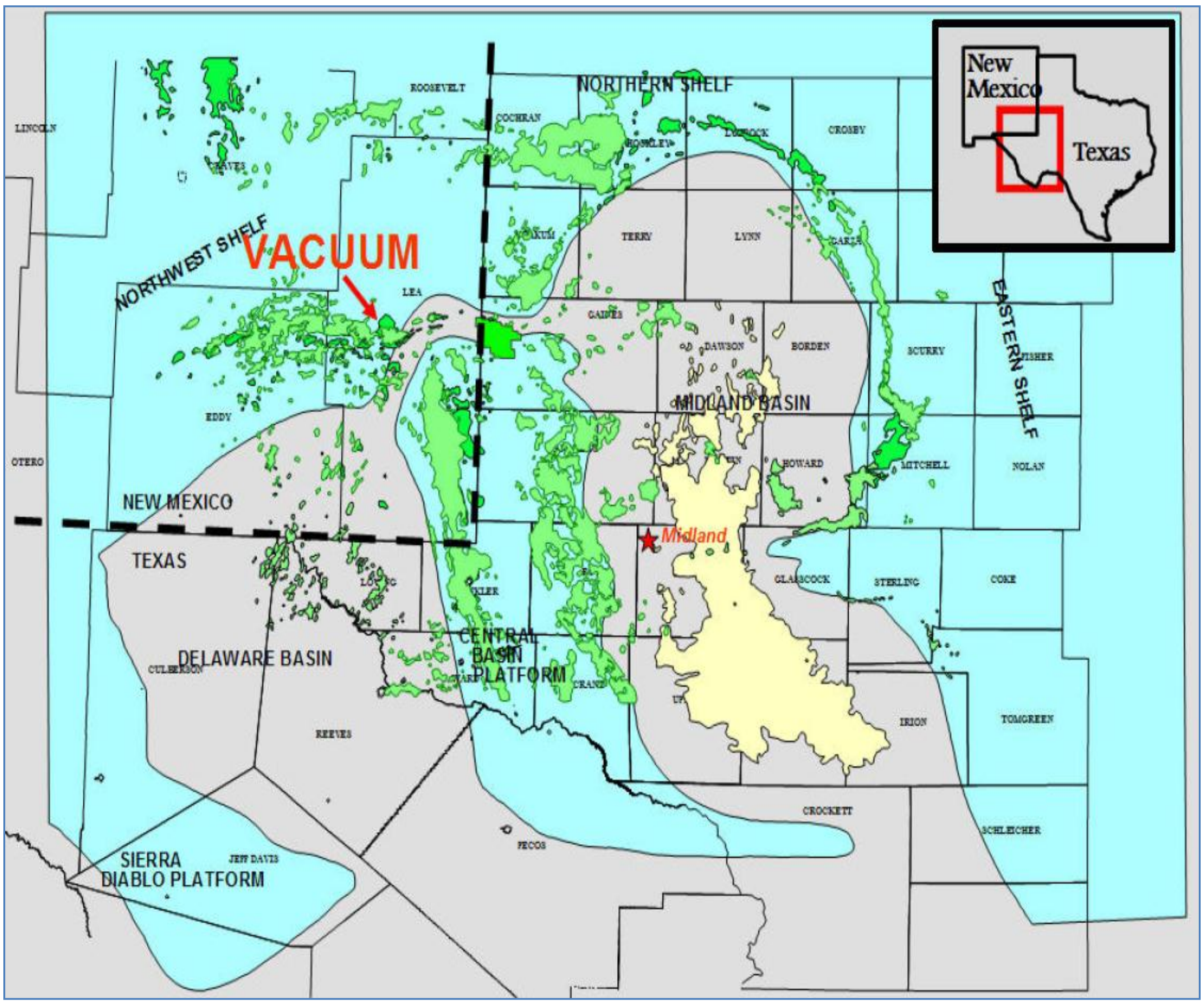


Figure 1. Map of Permian Basin (Adopted from Murray, et al, 2011)

The New Mexico portion of the Permian Basin has been a prolific oil and gas producing area since discovery of the Artesia Field in 1924. Cumulative production through 2010 has been 5.3 billion barrels of oil, 18 trillion cubic feet of gas, and 17.6 billion barrels of produced water (Table 1).

county	Cumulative Production by County		
	MMBO	BSCF	MMBW
Chaves	135	611	504
Eddy	1,041	5,577	3,382
Lea	4,013	12,033	13,515
Roosevelt	79	177	185
Total	5,268	18,398	17,587

Table 1. Cumulative production by county for southeast New Mexico (Data Source: GOTECH + 1992 Annual Report of the NM Oil and Gas Engineering Committee)

The extent of development extends to all four southeastern counties (Chaves, Eddy, Lea and Roosevelt) and from depths of as shallow as 1,000 ft. to as deep as 15,000 ft. The stratigraphic columns for the Delaware Basin, Northwest Shelf and Central Basin Platform are shown in figure 2 with the accompanying plays.

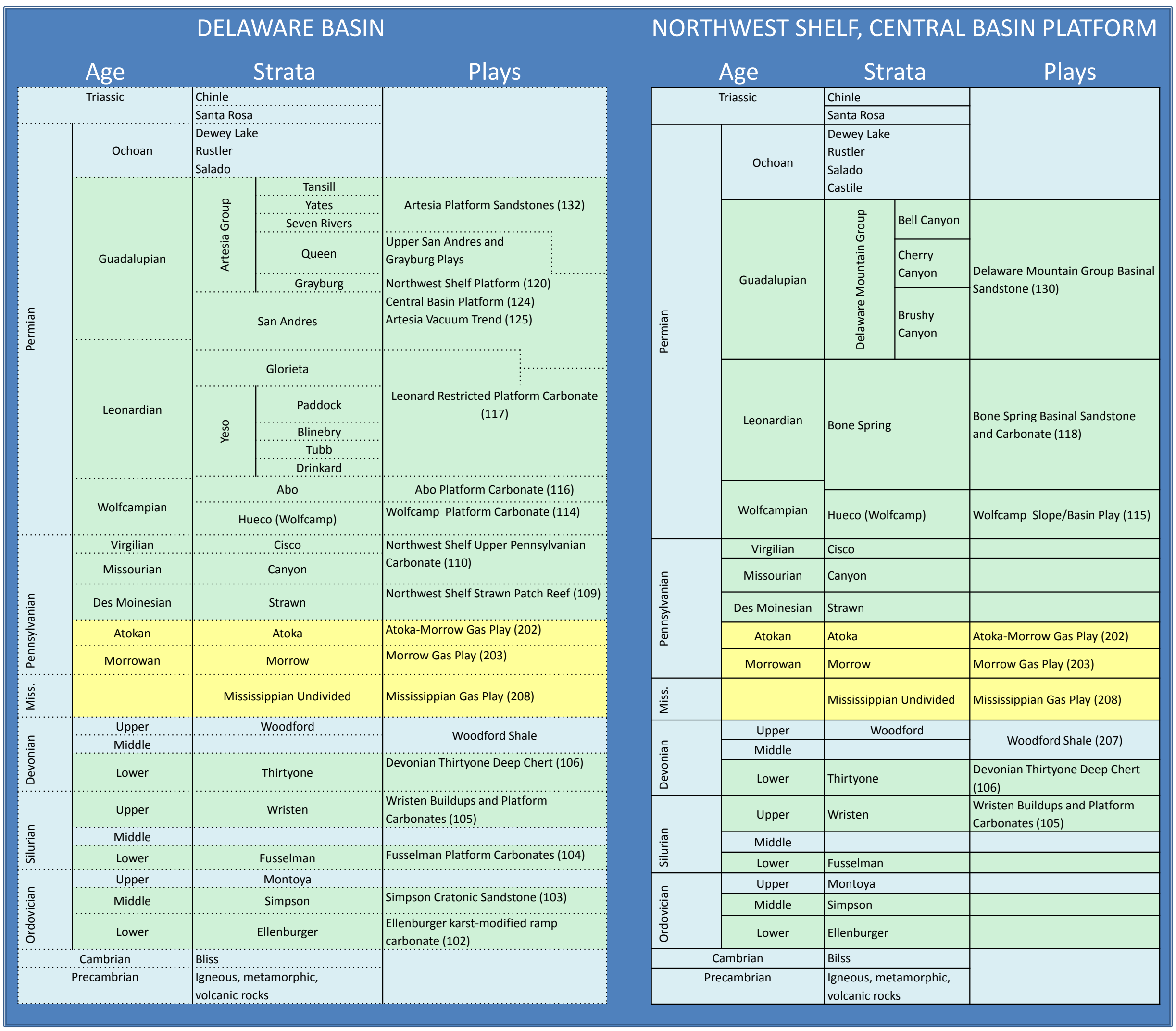


Figure 2. Stratigraphic columns for Southeast New Mexico

To identify potential the productive horizons were divided into 22 plays, originally defined by Broadhead, et al, 2004 and then modified to include gas plays and smaller pools. Figure 3 is a comprehensive map of the location of the important oil and gas pools in the region for all plays.

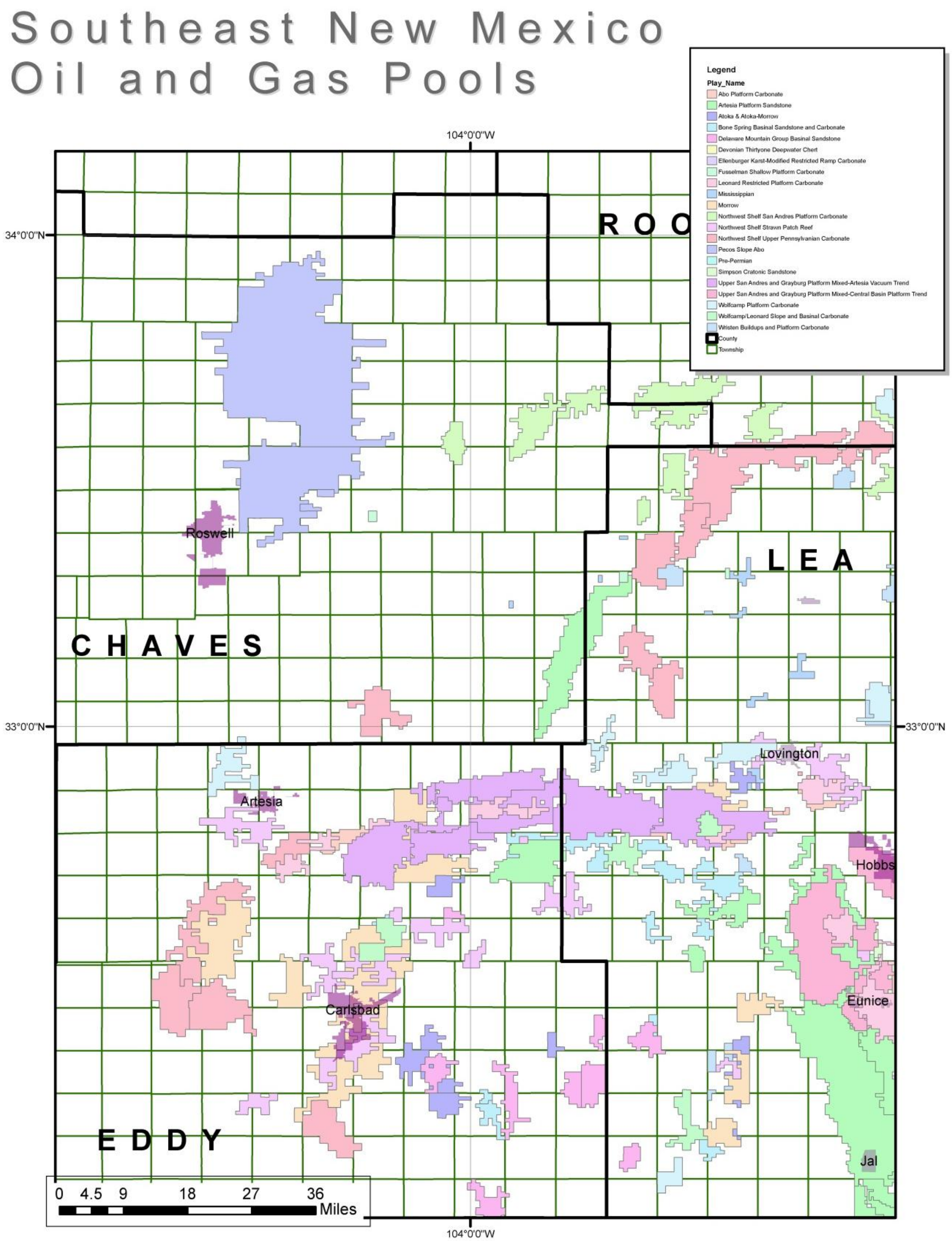


Figure 3. Important oil and gas pools for Southeast New Mexico

For convenience, the legend for the figures is shown in Figure 4. All pool maps are modified from the NMBGMR Circular 209 published in 2000. Important pools are composed of the top oil and gas producing pools for each play. Figures 5 and 6 are pool maps for oil and gas, respectively. Assessment potential for individual plays are included in the accompanying appendices.

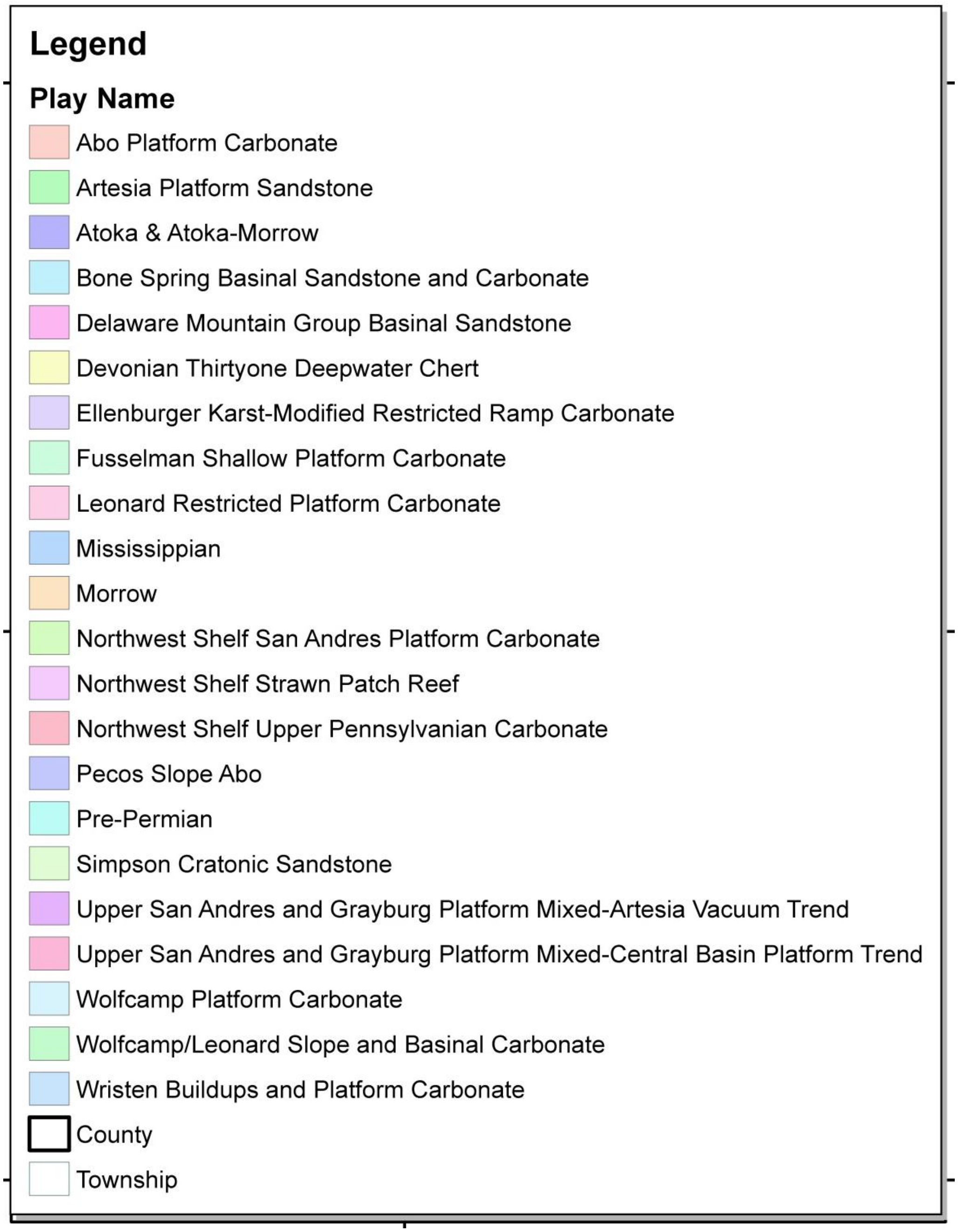


Figure 4. Legend of the play names for the pool maps

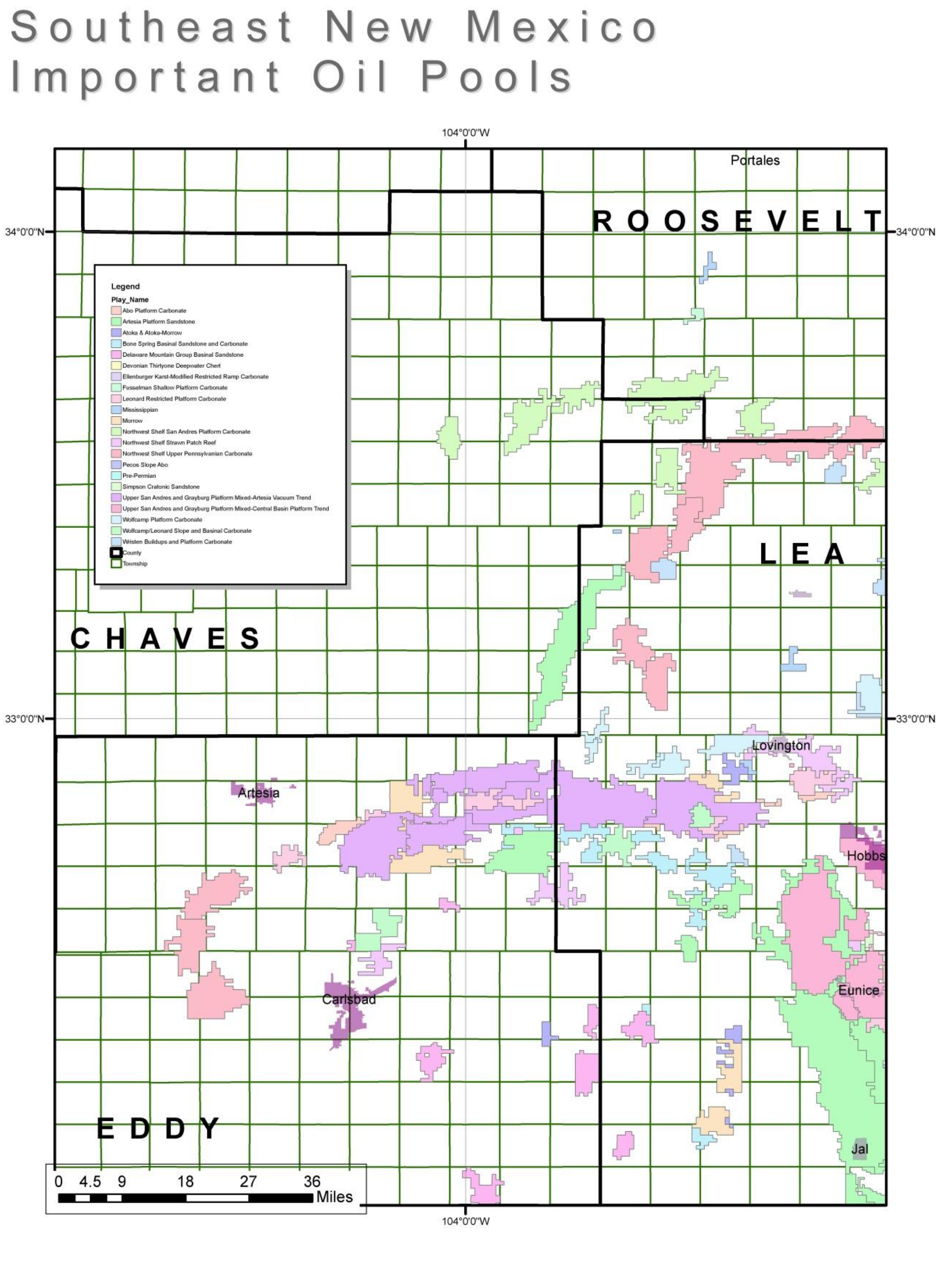


Figure 5. Important oil pools for Southeast New Mexico

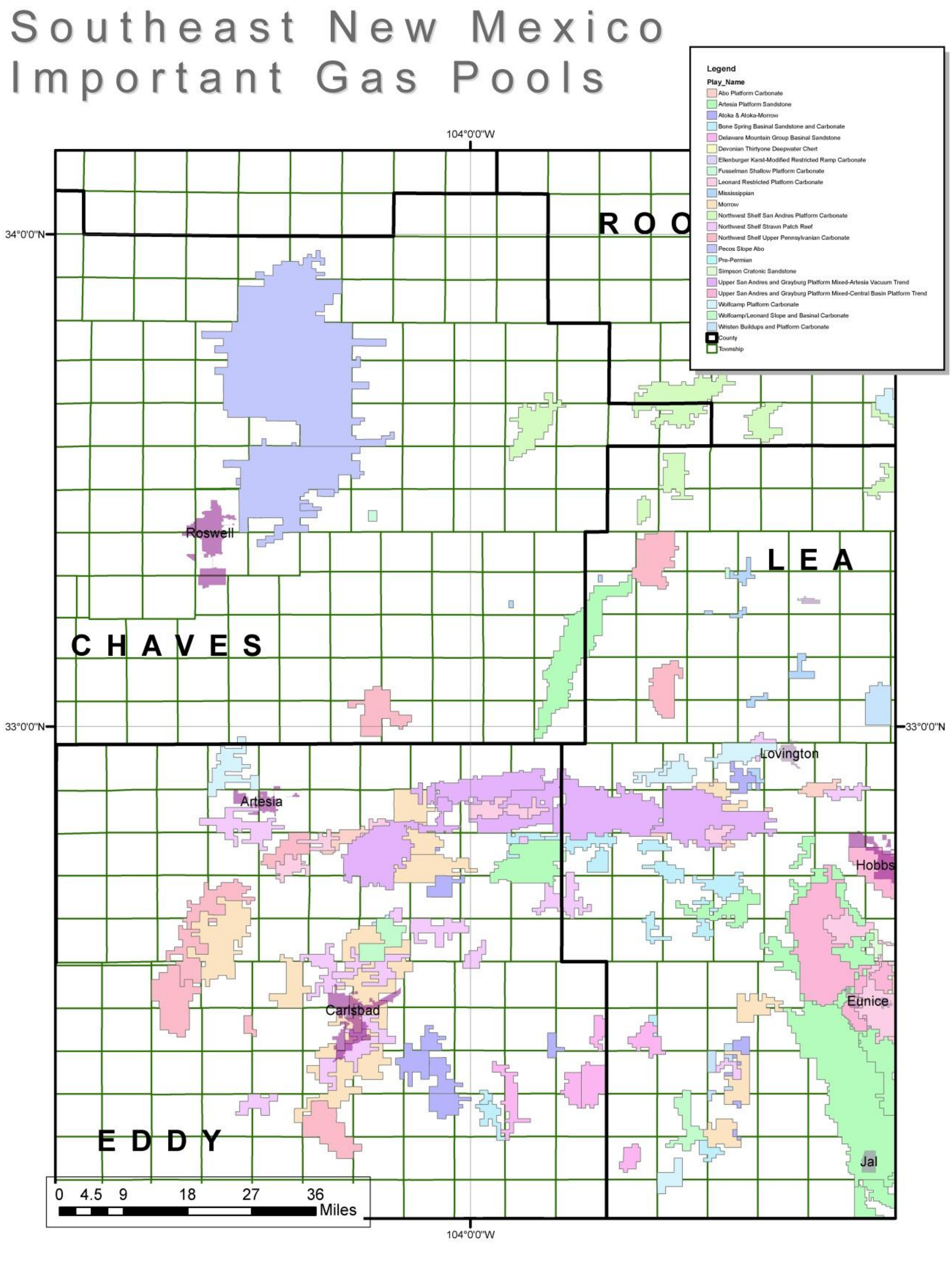


Figure 6. Important gas pools for Southeast New Mexico

Abo Shelf Sand Play

The potential for future development is ***low***. Additional development remains for 160-acre wells and significant potential exists for 80-acre infill development. However, the anticipated low wellhead gas prices will delay this development.

BRIEF SUMMARY OF GEOLOGY

The Abo shelf sands were formed as fluvial wedge deposits due to the rise and fall of sea level in mid Leonardian time. The sandstones are coarse–grained dark red to purple in color and often are conglomerate at the base (Bentz 1991). Major constituents are quartz plagioclase and feldspar. Cementing agents are clay, calcite, and anhydrites. The lateral wedge-out of fluvial clastics resulted in regional trapping across the play. Gas production occurs on the distal ends of the clastic wedge (Broadhead, 1984). Sandstones located North of Northwest and East of the gas producing area are water bearing. Mudstone facies to the South and West of Pecos slope become more dominant with the westward wedge out.

Gross thickness ranges from 400 ft in the West Pecos Slope pool to 650 ft. in the Pecos slope Abo producing area. Average pay thickness is 30ft. Permeability is low ranging from 0.03 to 0.05 mD. Average porosity is 12-14% and water saturation averages 38.5%. Reservoir energy is provided by a pressure depletion and gas expansion. Standard well spacing is 160 acres with a second well (effectively on 80 acre spacing) optional.

HISTORICAL DEVELOPMENT

Yates Pet Company re-entered the McConkey HX #1 well (section 10, T9S, R26E) in 1979 with modern well logging tools (compensated neutron formation density log and Dual Lateral Logs with Rxo curve) to verify reported gas shows from the Silurian-Devonian and Ordovician intervals. The results from these intervals were poor; however, the logging tools detected an 18 ft. thick sandstone with gas effect in the Abo formation (see Figure 1).

Low natural flow rates (70 MCFD) were encountered as a result of the low permeability. Artificial stimulation and fracture treating was necessary to acquire commercial production rates. Furthermore, under section 107 of the natural gas policy Act, FERC approved the Abo sandstones as a tight gas formation. This significant increased the wellhead gas price ans subsequently increased well activity in the Abo field. Production reached its highest in 1984, with 621 wells in use and 44.5BCF gas production that year.

In the mid-1990s the Pecos South and West pools were integrated into the main Pecos slope Abo field after pilot infill well developments revealed the south Pecos slope to be extension of the main Pecos slope Abo. Pecos slope South was identified to be only 5 miles from the main Pecos slope Abo pool with geologically equivalent pay zones but poorer wells and smaller drainage areas.

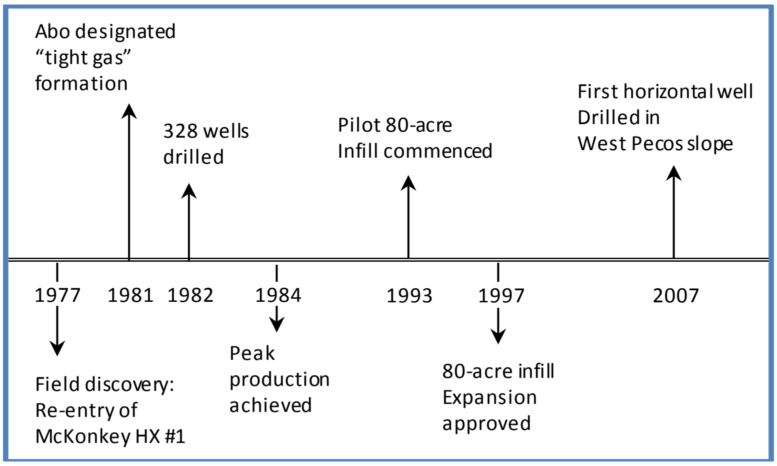


Figure 1. Timeline of events for the Pecos Slope Pool (modified from Bentz, 1992)

Figure 2 illustrates the production decline for the Abo shelf sand play. This play is comprised of the Pecos slope Abo pool, the Pecos slope west pool, the Pecos slope south pool and Pecos slope north pool. The annual production data shows peak production of 44 Bscf occurred in 1984; after which the field started declining. Cumulative gas production has been 522 Bscf through 2010. The main Pecos slope Abo pool is the largest of the four plays. The West and North Pecos Slope pools are less prolific due to poorer sandstone quality, poorer well performance and smaller drainage areas.

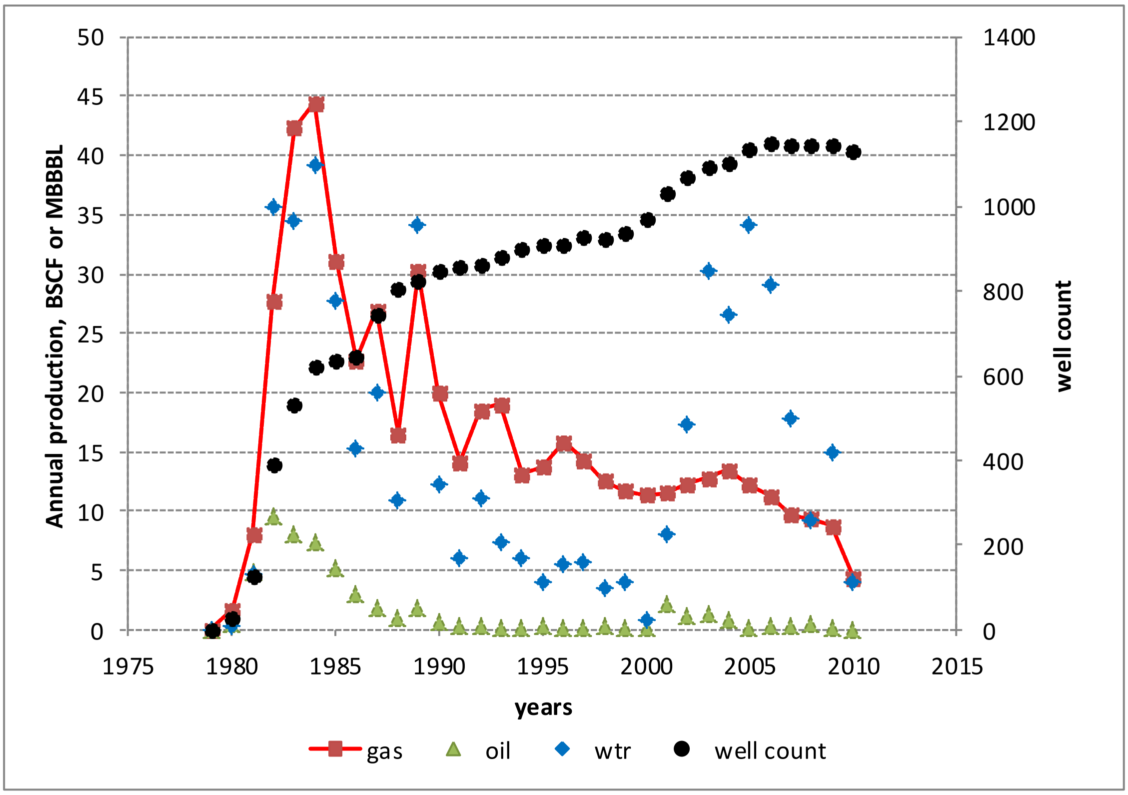


Figure 2. Annual production and well count for the Abo Shelf Sand play. (Source: Dwights)

The fluvial channel sands are shown in figure 3. Superimposed are plotted cumulative water or gas for each well. Notice the higher water production to the north and northeast delineating the pool boundary.

In 1993, a pilot infill drilling program commenced to test the feasibility of an optional second gas well on the 160-acre proration unit. Fifteen (80-acre) pilot wells were authorized and drilled. The engineering results of the Pecos pilot drilling Slope-Abo infill program were:

(a) of the fifteen wells which were drilled in the pilot project area, ten were successful, three marginal and two were dry holes;

(b) Bottomhole Pressures encountered in the pilot wells (800 psi) were greater than the existing offset wells (300 psi), but none achieved original bottomhole pressure of 1,125 psi.

(c) Production Rates for the average infill well was ~ 750 mcfd, substantially greater than the average offset well rate of 100 mcfd.

(d) For the 15 well-project the average well will recover 544 mmcf of gas. For the ten successful wells, the average recovery will be 800 mmcf. The remaining reserves for the offset wells is 200 mmcf per well. Consequently, the overall program will produce a total of 8 Bcf of reserves that otherwise would have been abandoned in the reservoir.

As a result of the pilot program, approval was granted to drill an infill well on an existing 160-acre spacing unit and thus recover additional gas reserves.

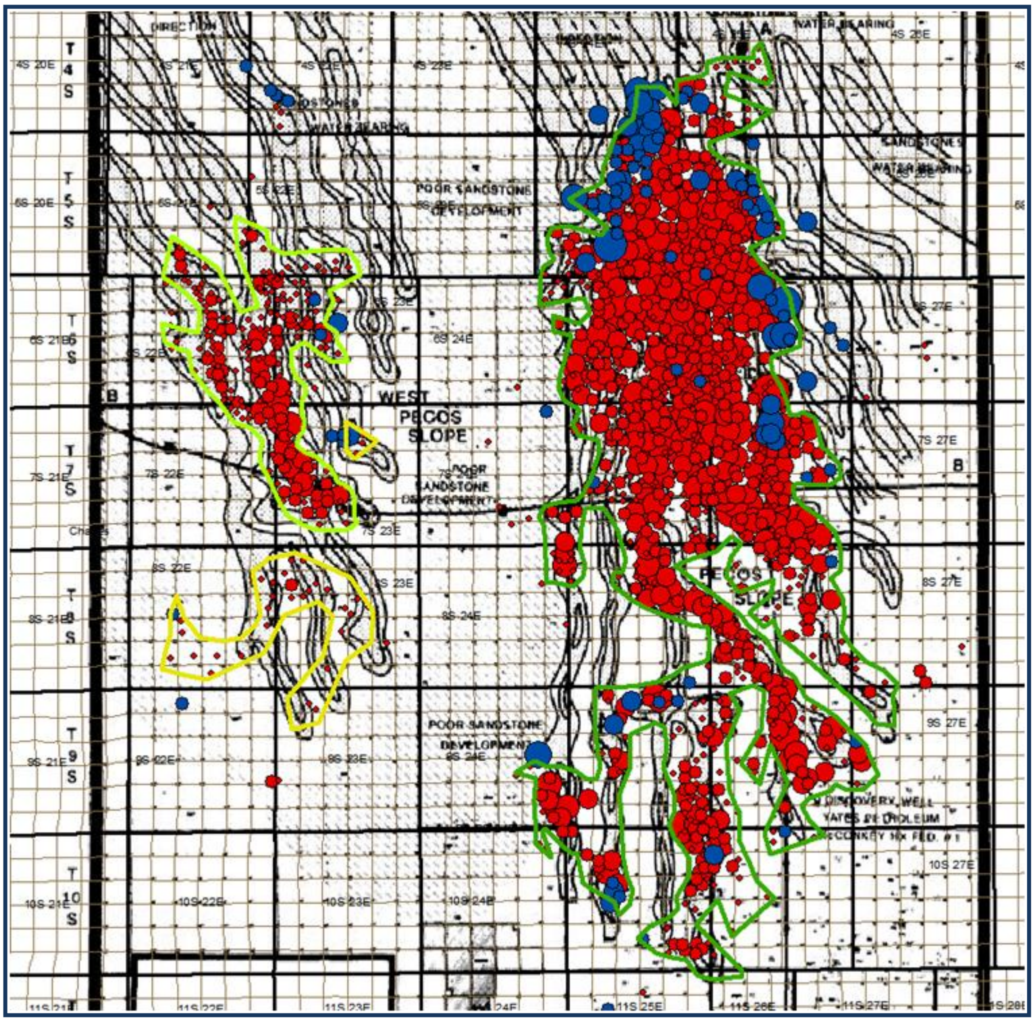


Figure 3. Net thickness map of the fluvial channel sands from Bentz, 1992 with superimposed cumulative bubble plots.

FUTURE DEVELOPMENT

The pilot infill program in 1993-94 demonstrated the feasibility of 80-acre spacing for the Pecos Slope Abo area. The productive area outlined in fig 3 represents 237,000 acres. If all 160-acre proration units were drilled then a total of 1,482 locations are possible. To date approximately 1,100 wells have been drilled, thus 280 160-ac locations are available. If a second well is drilled, then 3,000 additional locations are possible; however, a recent study (Engler, 2004) shows up to 60% communication between wells. The study recommended enhanced stimulation for future well completions rather than increasing infill well programs.

Since the Pecos Slope Abo is a gas play, future development is strongly dependent on gas price. Figure 4 illustrates this dependency from 2004 to 2011. As gas price dropped the number of completions went from 30 to none for 2010 and 2011. Development appears to occur at a price of approximately $7.00 to 8.00/mcf. According to the EIA, gas prices in this range won't occur until the year 2035.

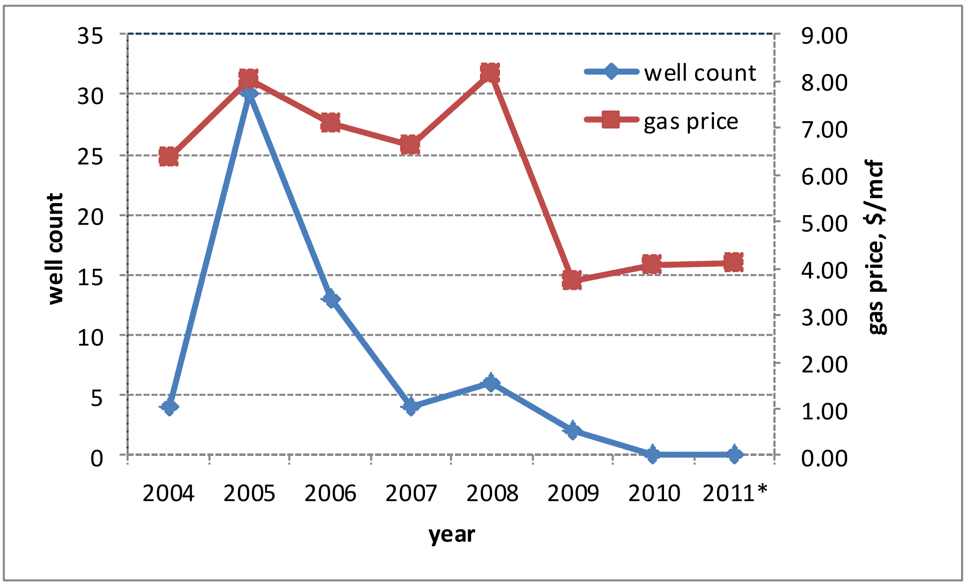


Figure 4. Correlation of annual well count to gas price for Pecos Slope Abo (Annual average lower 48 wellhead prices, 2009 dollars, EIA)

Two recently completed horizontal wells (2006 and 2008), the South Four Mile Draw C Federal #1H and the Four Mile B Federal #7Y in the Pecos Slope West, Abo have been marginal. Cumulative production through April 2011 has been 23 and 34 MMSCF, respectively.

In summary, future potential exists for infill drilling the Pecos Slope Abo area (Figure 5). However, low gas prices coupled with poor performance will delay development. Also, production from initial horizontal well tests has been disappointing. As a result effective stimulation will be important for future development.

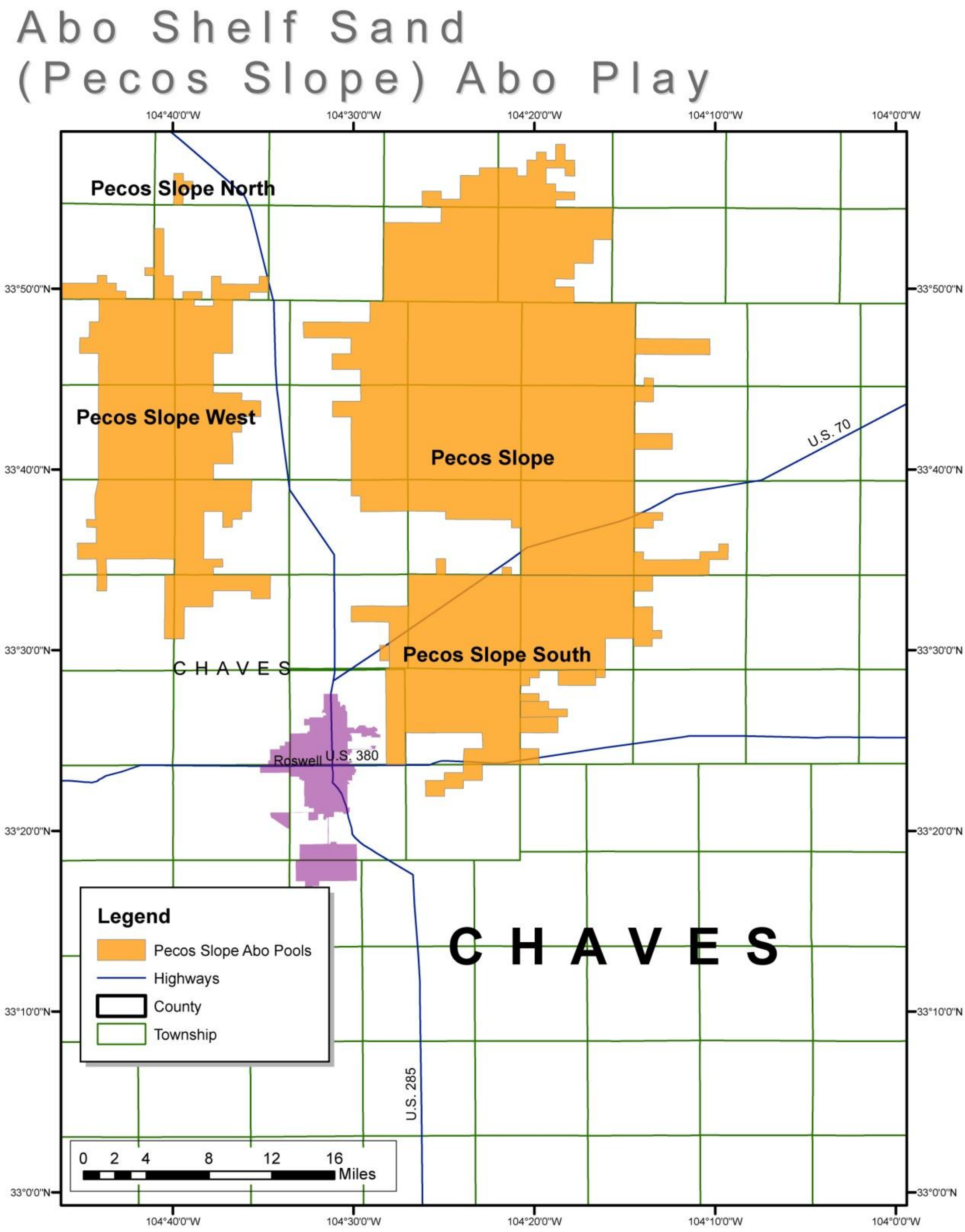


Figure 5. Pool map for the Abo Shelf Sand play

Abo Platform Carbonate Play

The potential for future development is ***high***.

Brief Summary of Geology

Reservoirs of the Abo Platform Carbonate play (Fig. 1) lie along the south margin of the Northwest Shelf and along the west margin of the Central Basin platform. In New Mexico, the play is divided into two subplays, the Abo Reef subplay (including Empire, Vacuum, Lovington, Corbin, Double A, Double A South, Maljamar, etc) and the Abo Carbonate Shelf subplay (including Vacuum North, Monument, Monument North, Wantz, Brunson South, etc).(Broadhead, 1993)

The Abo is a transgressive barrier reef (Fig. 1) which separated lagoonal deposits on the northwest shelf from clastic deposits in the Delaware Basin during lower Leonard time. The reef probably grew on a preexisting platform or hingeline along the rim of the Delaware Basin. The reef grew northward, transgressing the shelf deposits, as well as vertically in the lower Leonard section (LeMay, 1960).

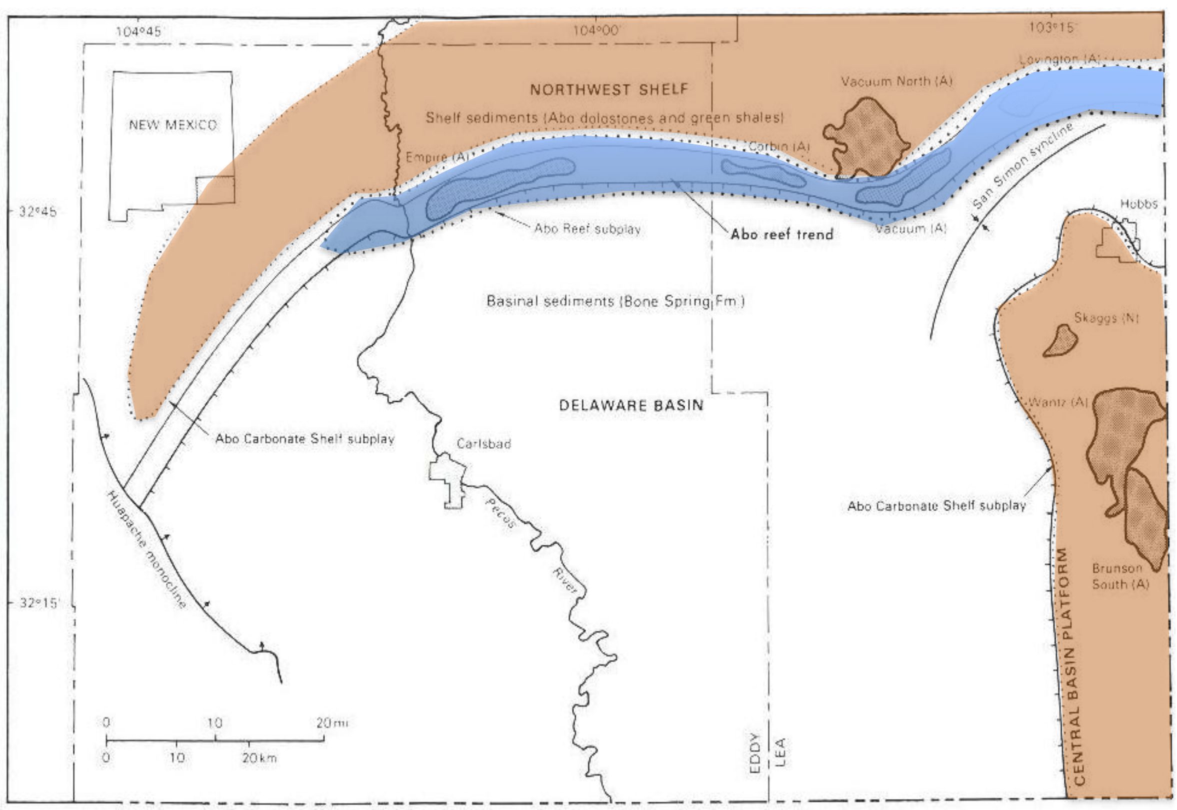


Fig. 1 Location of Abo subplays in the New Mexico part of the Abo Platform Carbonate play (Broadhead, 1993)

Abo carbonate reservoirs are Leonardian (Permian) in age (Fig. 2).

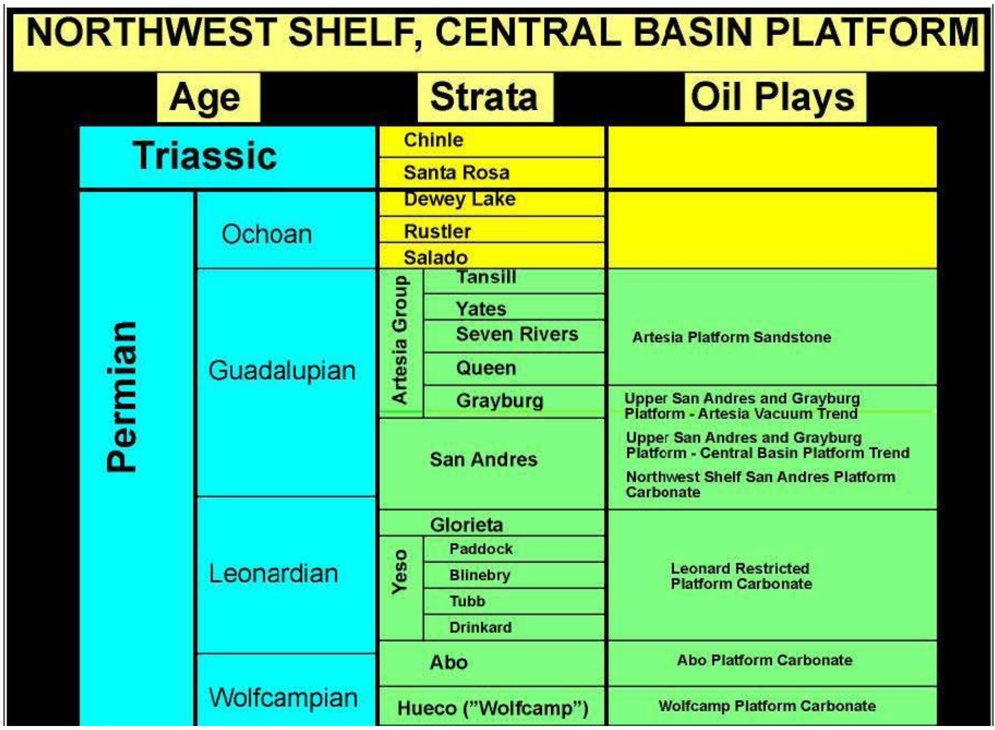


Fig. 2 Stratigraphic chart showing relationship of Abo carbonate strata on the Northwest Shelf to equivalent basinal strata of the Delaware Basin.

Traps in the Abo Reef subplay are located along the southern edge of the Northwest shelf. Depths to productive Abo range from approximately 6,000 ft at the Empire reservoir to approximately 8,650 ft at the structurally deeper Vacuum reservoir. Traps are predominantly stratigraphic and are located in porous reefal masses 5 to 13 mi long and 1 to 5 mi wide (Broadhead, 1993).Traps in the Abo Carbonate Shelf subplay,although poorly documented, appear to be formed by broad, low-relief anticlines (Broadhead, et al, 2004).

The Abo reef is a very clean, white to light tan or gray (commonly anhydritic) dolomite, varying from dense micro-and finely crystalline to coarsely crystalline in texture. The original reef framework probably consisted predominantly of hydro-corals, sponges and algae colonies (LeMay, 1960).

The Abo reef is a good reservoir because of well-developed secondary porosity including vertical fractures.

HISTORICAL DEVELOPMENT

The early discoveries of oil where in the Abo carbonate shelf subplay; specifically the Monument and Wantz Fields (See Fig. 3). The Abo reef subplay was first discovered to be oil-productive when Skelly Oil Co. deepened a well beneath the shallow San Andres production in Lovington field in December 1951. The Abo reef was topped at 8,117 feet and flowed oil on a drill stem test. During the early development of the Lovington Abo field, the rapid facies changes mentioned above were noted traversing the reef from south to north.

It was not until the discovery of Empire Abo field by Pan American Petroleum Corp. and Hondo Oil and Gas Co. in November 1957, and the early development of this field that the Abo reef became a major exploration target. Pay thicknesses in excess of 600 feet were encountered at depths from 5,500 to 5,800 feet. Rapid development followed (LeMay, 1960).

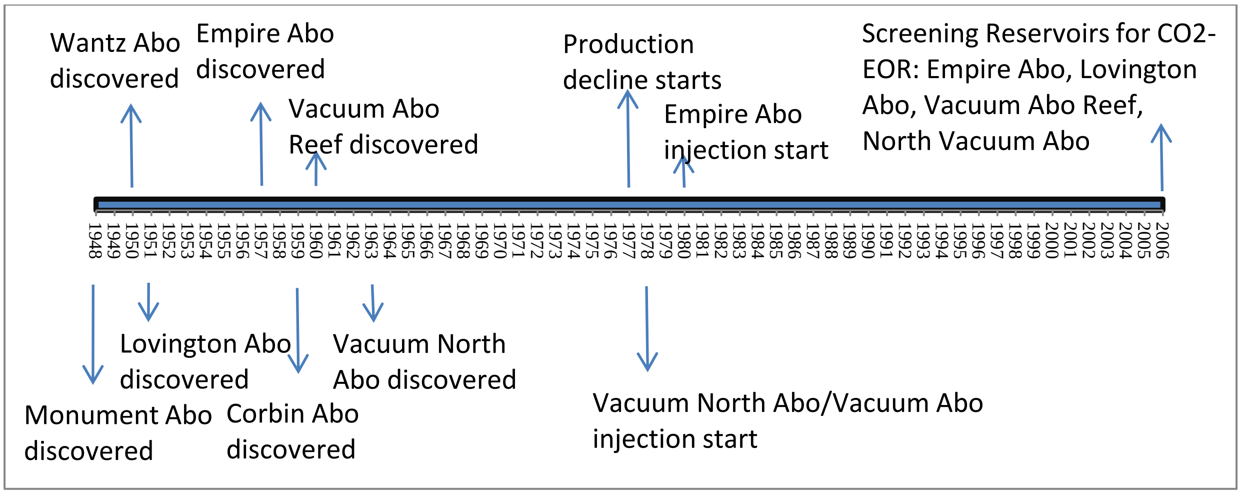


Fig. 3 The development history of Abo Platform Carbonate play

Recent activity in this play is shown in Figure 4. Each chart represents a five year time window of wells that are active in this play. Notice in the 2005-10 time period the increase in activity north of the existing shelf trend which includes Empire and Vacuum pools. The County Line Pool to be discussed later is located in this new active area.

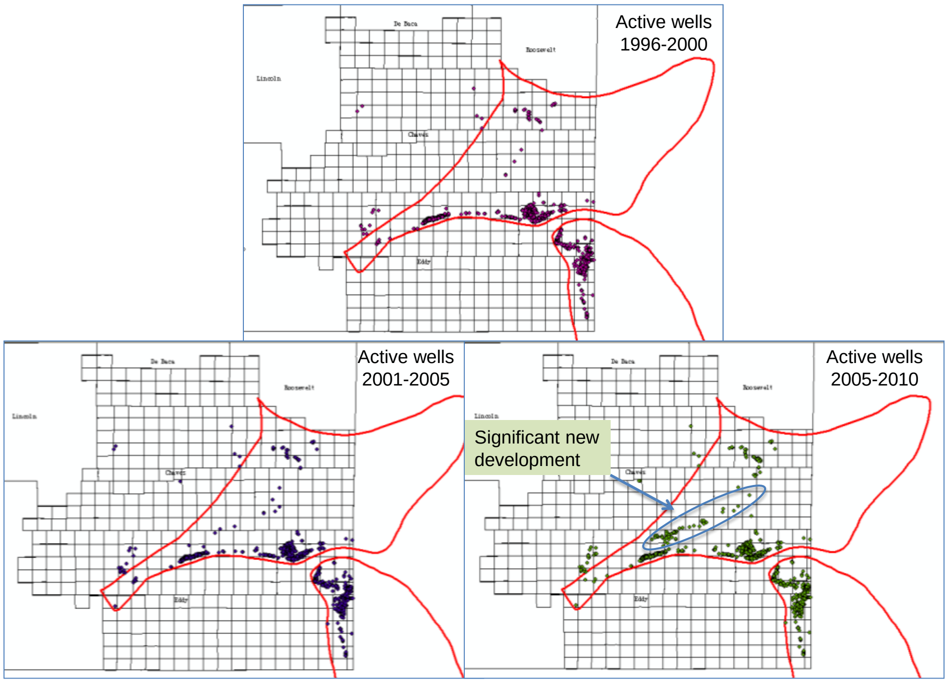


Fig. 4 Activity in the Abo Platform Carbonate Play

The Abo Platform Carbonate Play has produced 474MMBO and 893 BCF gas by May 2010 (Table 1, figure 5). Reservoirs in the Abo Reef subplay are more prolific, producing370 MMBO oil and 633 BCF gas. Within this subplay, production is dominated by the Empire Abo, which has yielded 224 MMBO or 60% of the oil produced and 439 BCF or 69% of gas produced. Reservoirs in the Abo Carbonate Shelf subplay have produced 104 MMBO oil and 261 BCF gas.

	Abo Play	Abo Reef Subplay	Abo Carbonate Shelf subplay
Oil (MMBO)	474	370	104
Gas (BCF)	893	633	261
Water(MMBW)	525	404	121

Table 1. Production data for the Abo Platform Carbonate play with two subplays
(data source:Dwight's Energydata, Inc.+digitized data)

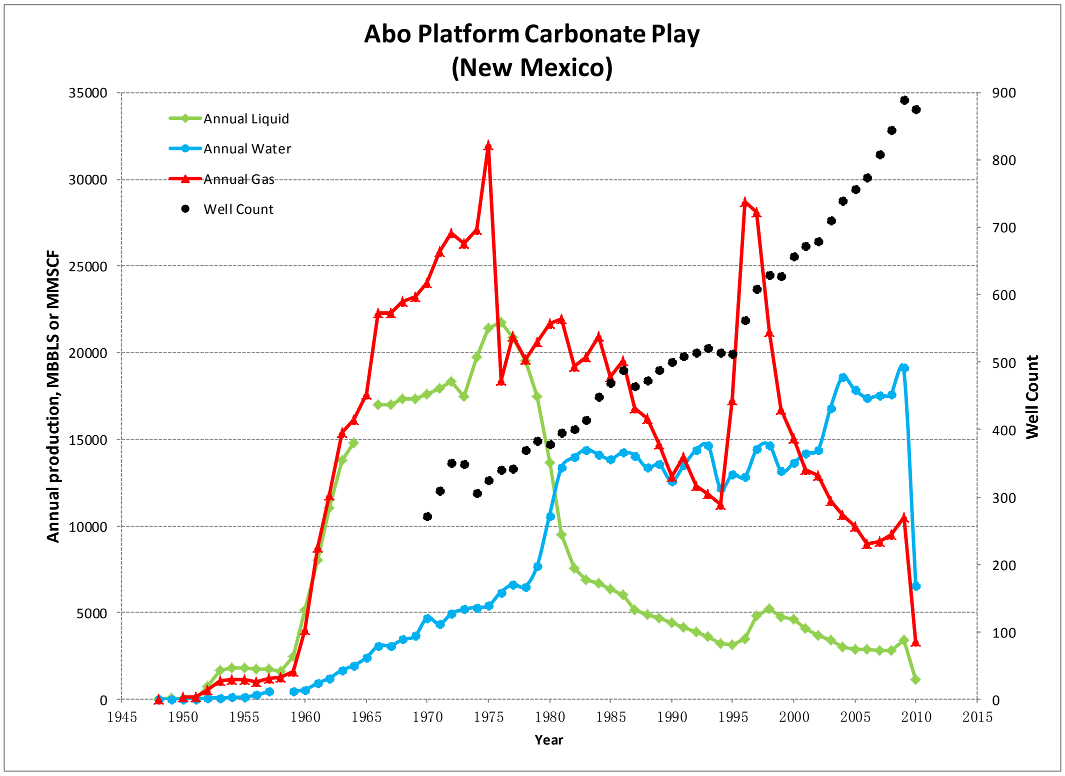


Fig. 5 Abo Platform Carbonate play annual production and well count
(data source: Dwight's Energydata, Inc.+digitized data)

There are 76 discovered reservoirs in the New Mexico part of the Abo Platform Carbonate play. Cumulative production for the top 10 oil reservoirs was 454 MMBO (96% of the total oil produced) and 806 BCF (90%). Individual reservoir statistics are shown in table 2.

Reservoir Name	Disc overy	Cum. Liquid	Cum. Gas	Cum. Water	Cum. Liquid	Cum. Gas	Cum. Water
	Year	(MMBBLS)	(BCF)	(MMBBLS)	frac.	frac.	frac.
EMPIRE;ABO	1957	223.93	438.66	81.53	0.472	0.491	0.155
VACUUM;ABO REEF	1960	86.31	138.89	119.94	0.189	0.155	0.228
VACUUM NORTH;ABO	1963	62.20	58.09	61.07	0.131	0.065	0.116
LOVINGTON;ABO	1951	33.32	19.71	171.20	0.070	0.022	0.326
CORBIN;ABO	1959	15.18	23.44	18.11	0.032	0.026	0.034
MONUMENT;ABO	1948	12.13	23.76	33.19	0.025	0.026	0.063
WANTZ;ABO	1950	10.59	92.50	4.77	0.022	0.103	0.009
MIDWAY;ABO	1977	2.68	5.60	1.58	0.006	0.006	0.003
BUCKEYE;ABO	1960	2.65	3.46	4.45	0.006	0.004	0.008
DOUBLE A;ABO	1959	2.31	2.81	4.55	0.005	0.003	0.009
Sum		454.50	806.93	500.4	0.959	0.903	0.953
Total Abo Field		473.97	893.27	525.01	1.000	1.000	1.000

Table 2. Top 10oil producing reservoirs in the Abo Platform Carbonate play

Abo Reef Subplay

Annual Oil production in the Abo Reef subplay has declined from approximately 20 MMBO in 1975 to approximately 1MMBO in 2009 (Figure 6). The gas decline roughly parallels the oil decline except for the blowdown of the Empire Abo gas cap in the mid-1990s. Water production increased dramatically during 1979 to 1983 due to breakthrough of water in the Empire, Vacuum Reef and Lovington Fields.

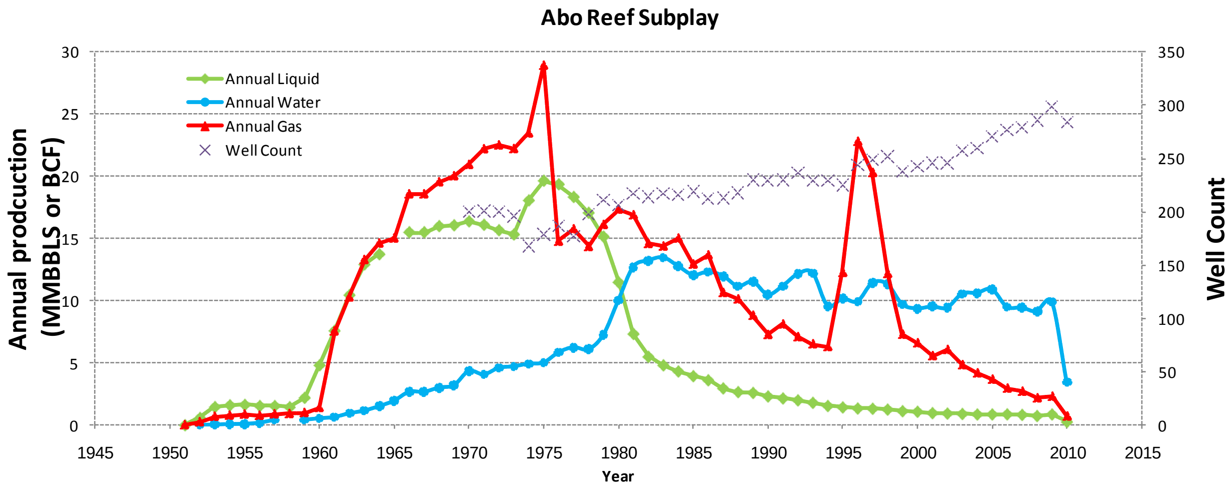


Figure 6.Abo Reef subplay annual production and well count
(data source: Dwight's Energydata, Inc.+digitized data)

The Empire Abo pool is the most significant pool in the entire play. The pool was discovered in 1958 (See Figure 7). By Oct. 1973, approximately 97% of the play was unitized as the Empire Abo Unit. By shutting in high GOR wells, conserving reservoir energy, and returning all available plant residue gas to the secondary gas cap (injection began in June 1974) ultimate oil and NGL recoveries were increased compared to primary depletion. The gas reinjection program caused a gas production peak in mid-1970s. The second gas production peak appeared at blowdown timing for the empire Abo Unit.

As this important reservoir began to decline in the late 1970's water injection was initiated in 1980 to arrest this decline. Gas and water injection and injection well count are shown in Figure 8. Water injection peaked in 1992. By 1995 gas injection ceased and the blowdown of the gas cap began.

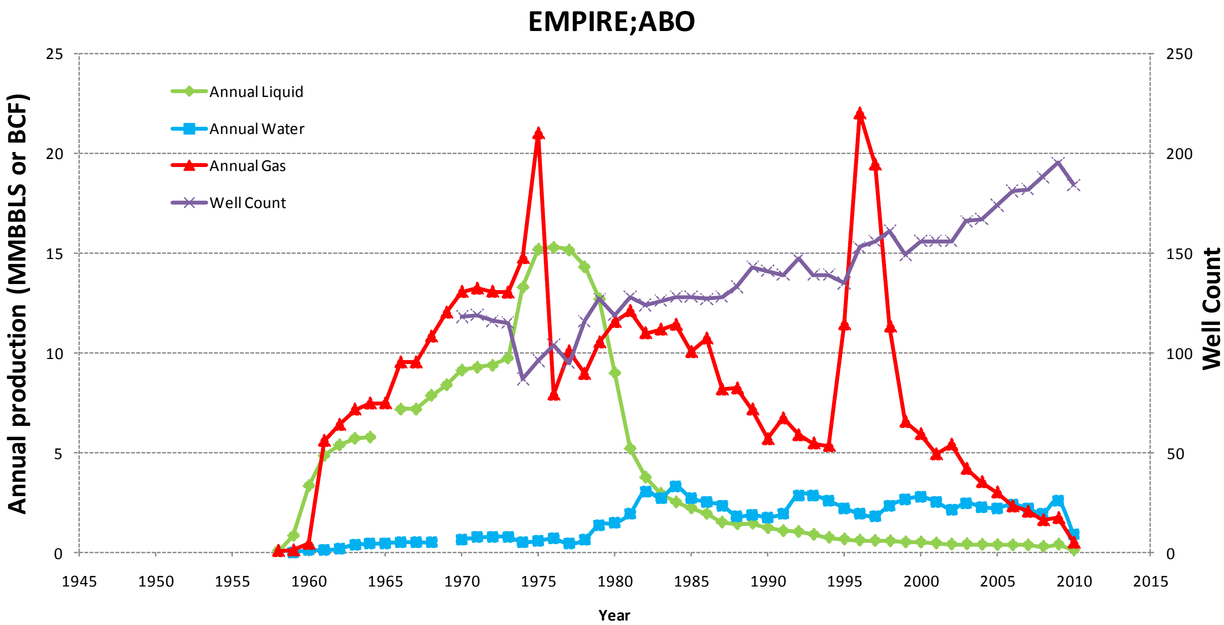


Fig. 7 Empire Abo (Abo Reef Subplay) annual production and well count
(data source: Dwight's Energydata, Inc.+digitized data)

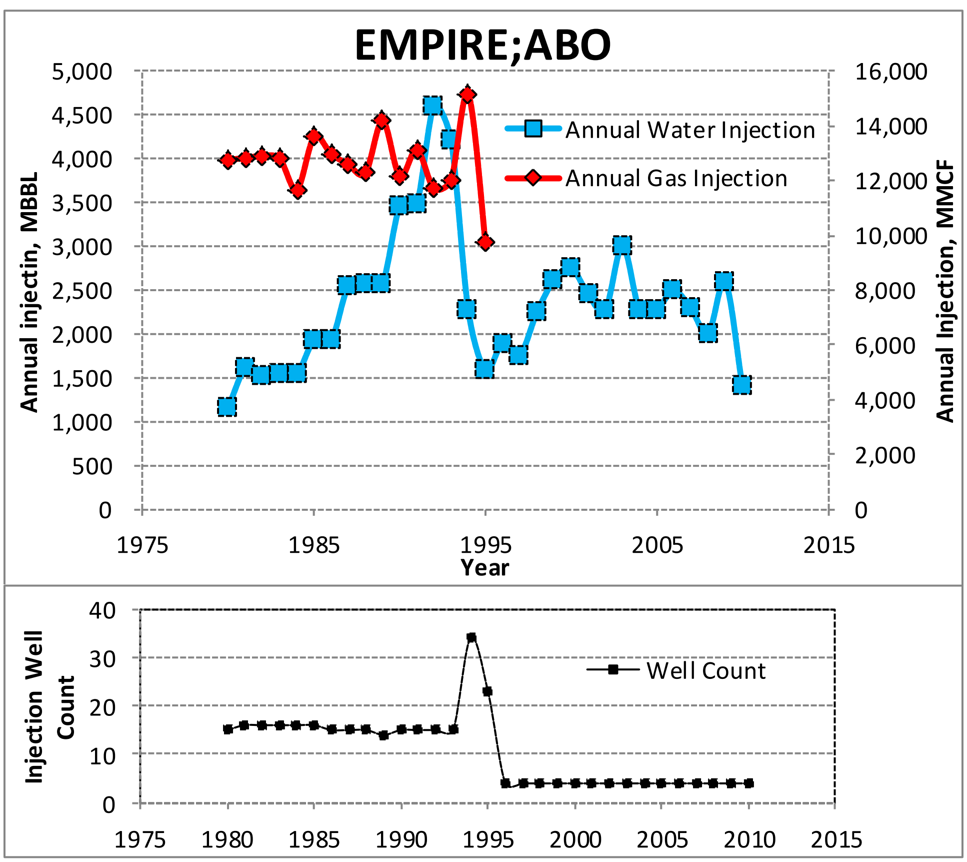


Fig. 8 Annual injection and well count for Empire Abo Pool .
(data source: Dwight's Energydata, Inc.+digitized data)

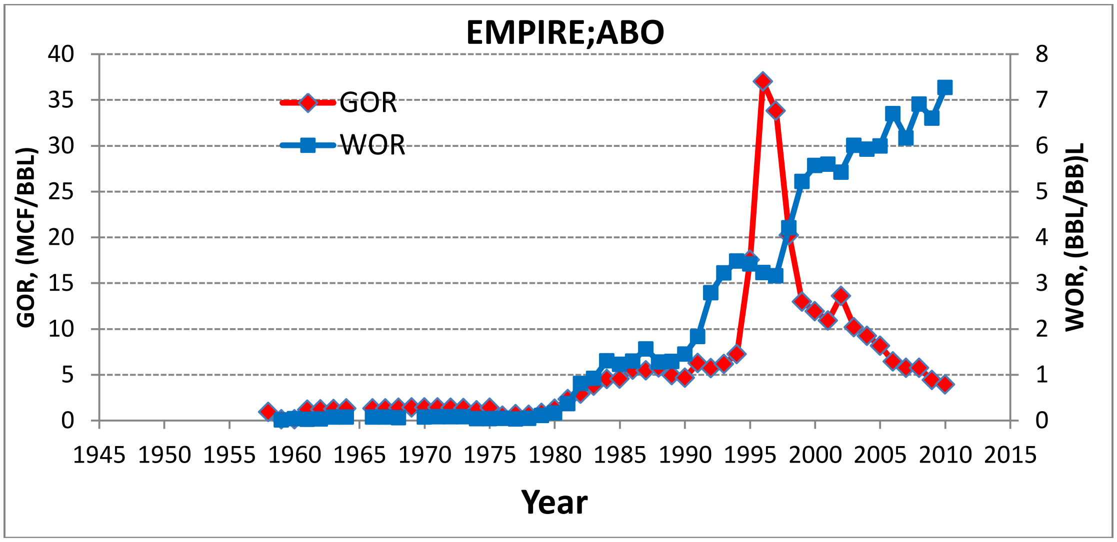


Fig. 9 GOR/WOR of Empire Abo
(data source: Dwight's Energydata, Inc.+digitized data)

The Vacuum Abo Reef pool commenced production in 1963. Oil production peaked in 1968 at an annual average rate of over 16,500 bopd and has been declining ever since to 900 bopd for 2009 (Fig. 10). Water injection started in 1978. (Fig. 11).

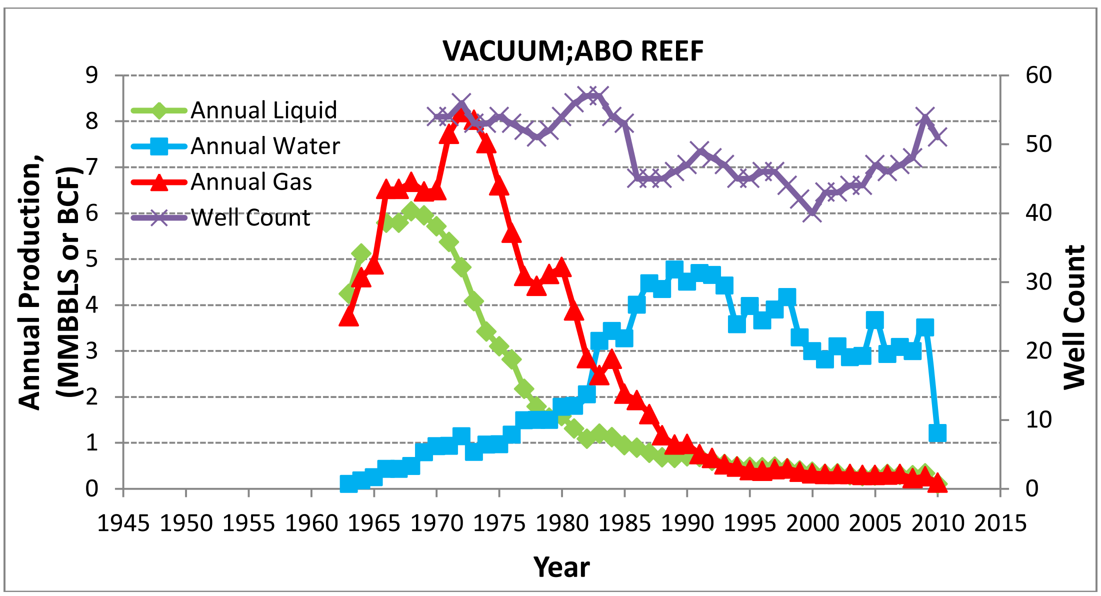


Fig. 10 Vacuum Abo Reef (Abo Reef Subplay) annual production and well count
(data source: Dwight's Energydata, Inc.+digitized data)

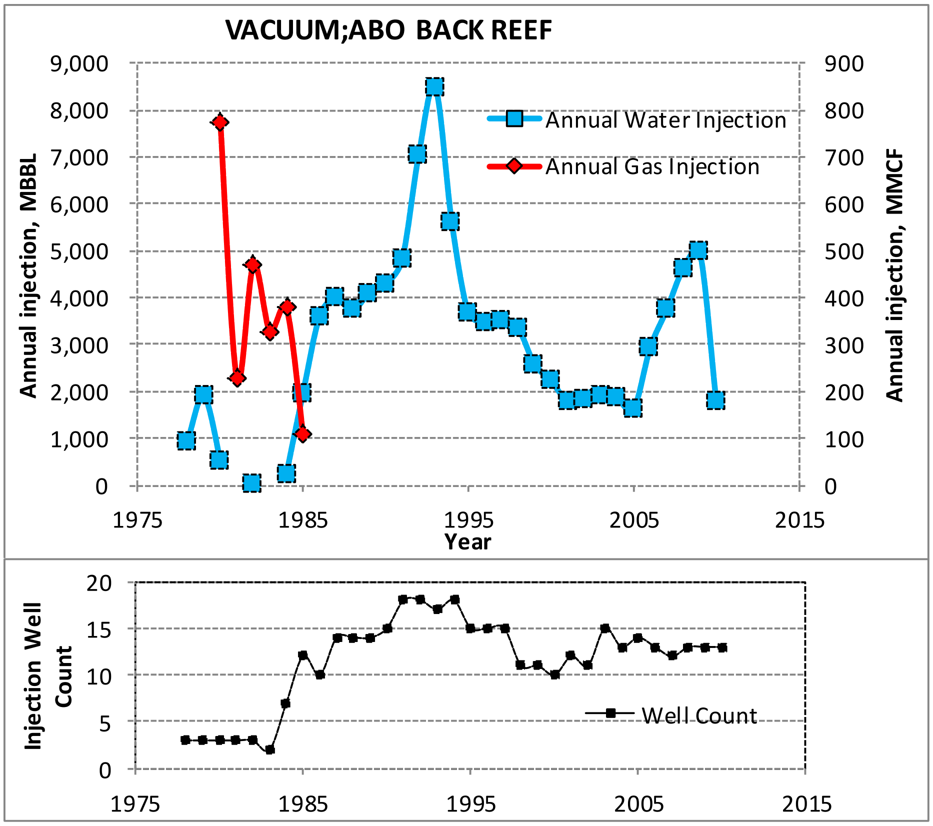


Fig. 11 Annual injection and well count for the Vacuum Abo Reef Pool .
(data source: Dwight's Energydata, Inc.+digitized data)

The Lovington Abo pool was discovered in 1951. Unlike the Empire and Vacuum Reef, no injection has occurred in the Lovington pool due to its natural water drive (Fig. 12); which is responsible for the majority of water production in the abo play.

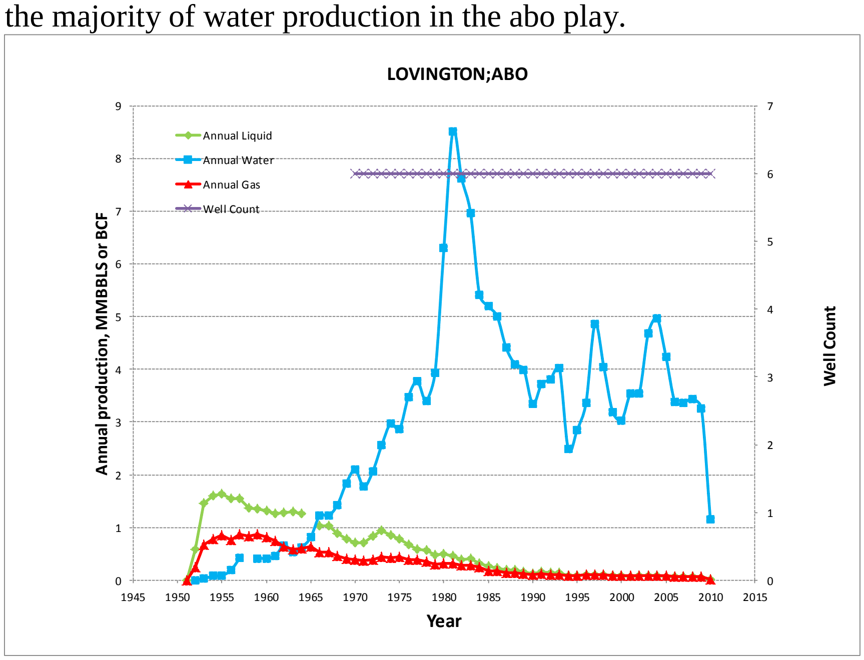


Fig. 12 Lovington Abo (Abo Reef Subplay) annual production with well count
(data source: Dwight's Energydata, Inc.+digitized data)

Abo Carbonate Shelf Subplay

In contrast, annual gas production in the Abo Carbonate Shelf subplay has increased during the same period from approximately 3 BCF in 1970 to approximately 8 BCF in 2009. The oil production in this play roughly shows a constant production rate at 3 MMBO. The increase in gas production has resulted from extensive infill and extension drilling (Fig 13). The number of producing wells increased from approximately 100 during 1970 to approximately 600 during 2009.

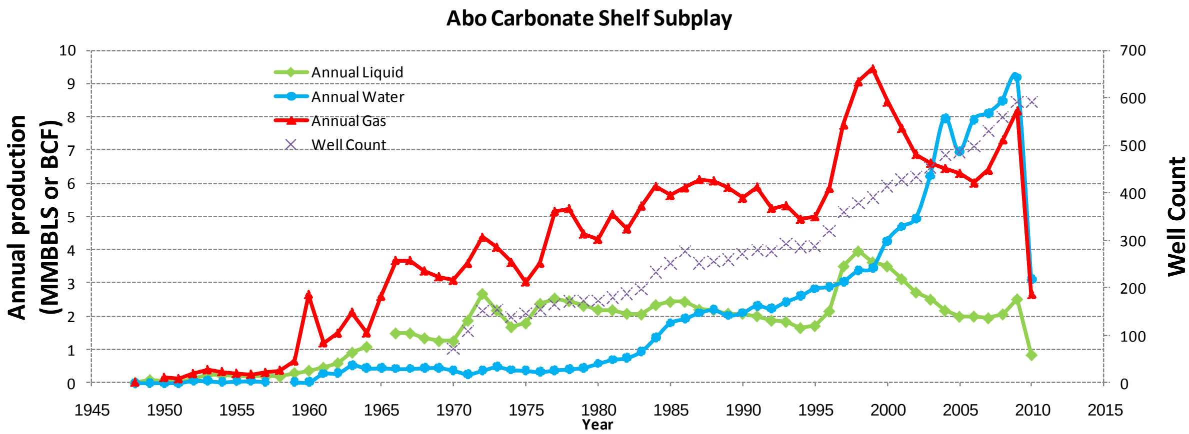


Figure 13.Abo Carbonate Shelf subplayannual production and well count
(data source: Dwight's Energydata, Inc.+digitized data)

The most prolific pool in the shelf subplay is the North Vacuum Abo pool. Production in this pool started in 1963 and peaked in 1972 at 7,400 bopd (Fig 14). Oil production has declined to 2,250 bopd in 2009. Water injection was initiated in 1978.

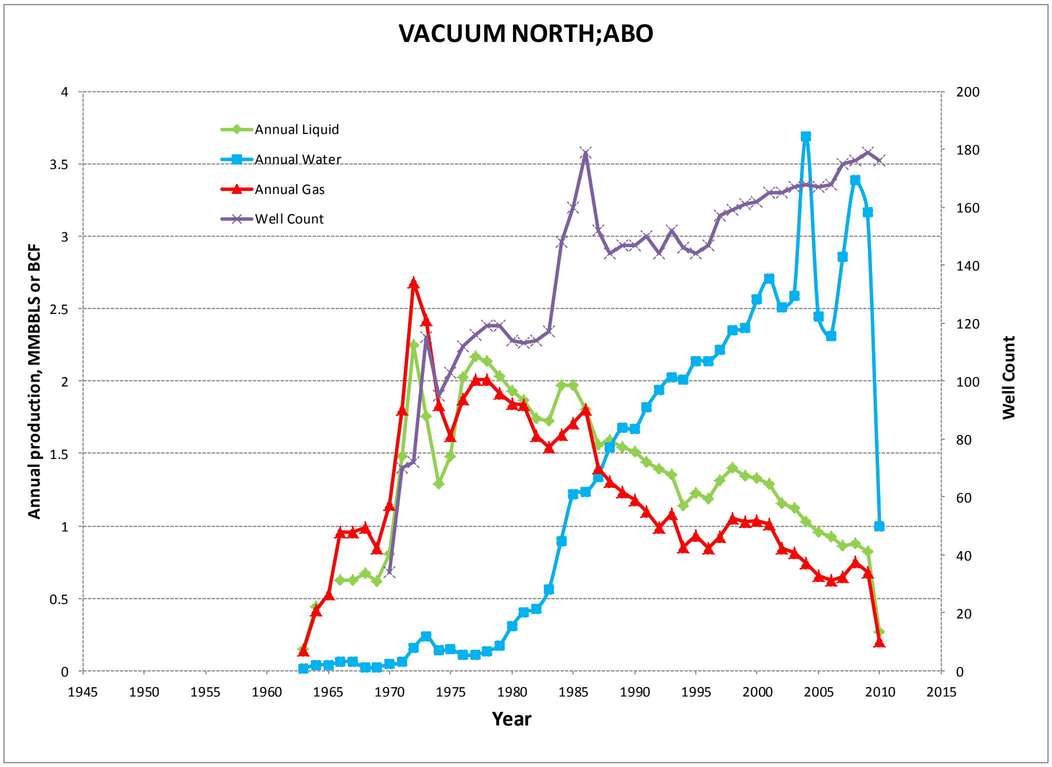


Fig. 14 Vacuum North Abo (Abo Carbonate ShelfSubplay) annual production with well count
(data source: Dwight's Energydata, Inc.+digitized data)

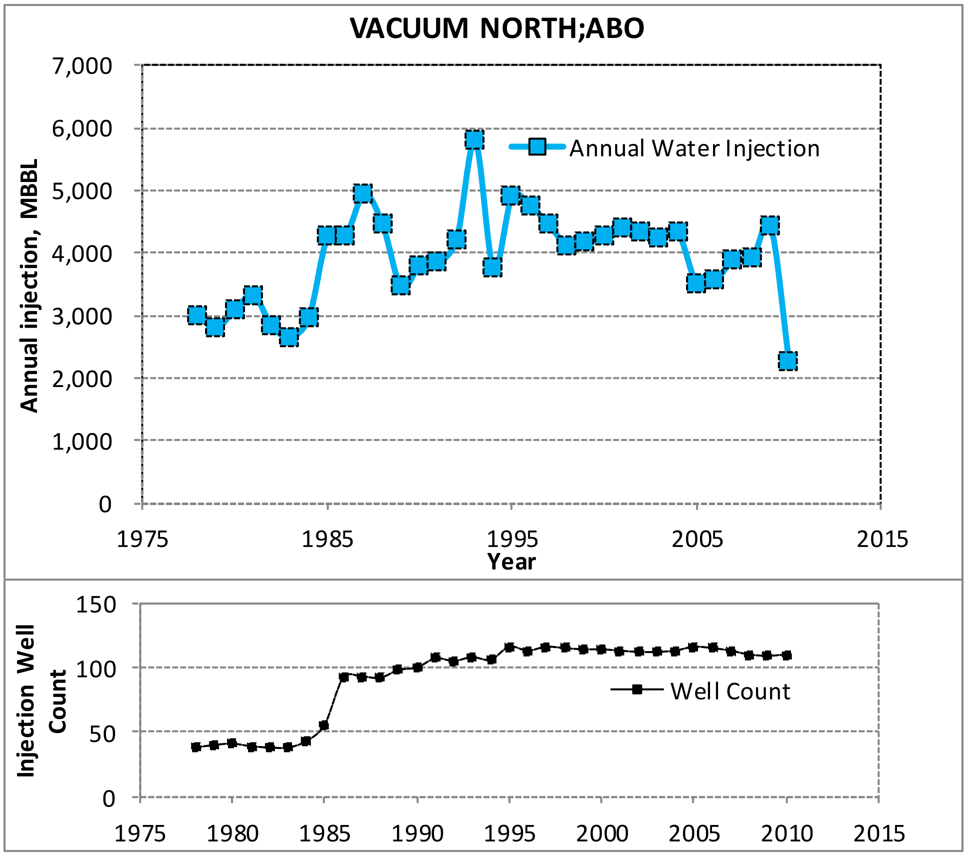


Fig. 15 Annual injection and well count for the North Vacuum Abo Pool
(data source: Dwight's Energydata, Inc.+digitized data)

Production from the play increased during the latter half of the 1990's for this subplayas production in the Monument reservoir increased as a result of additional drilling. Figure 16 shows the increase in wells and corresponding production for this pool.

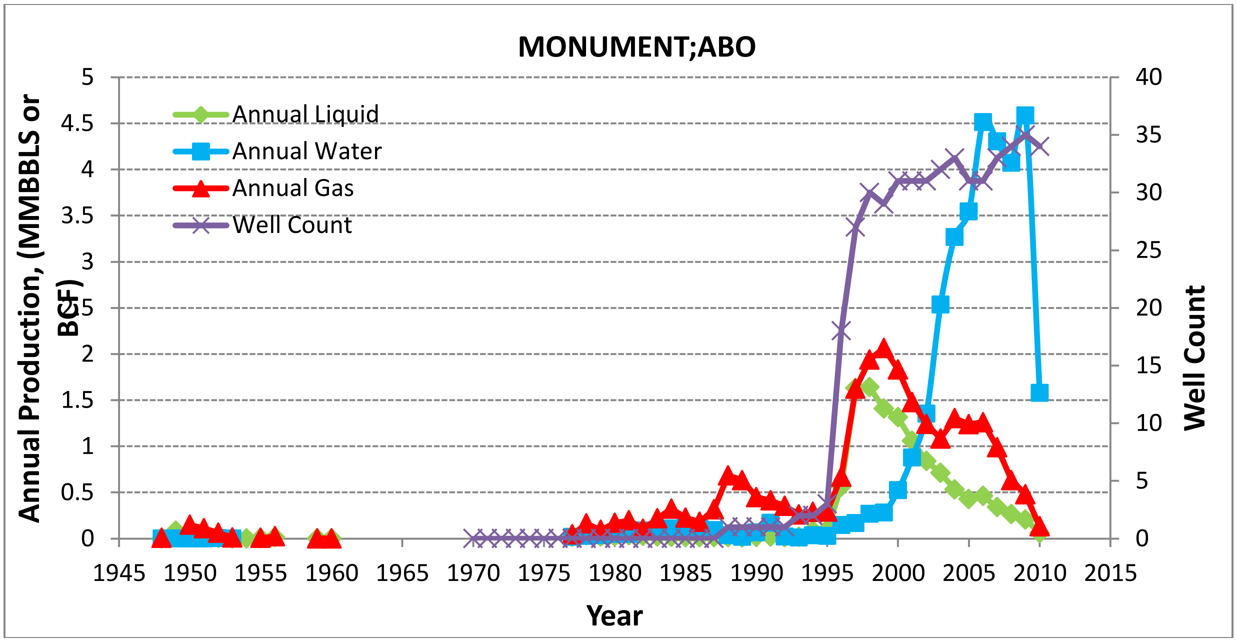


Fig. 16 Monument Abo (Abo Carbonate ShelfSubplay) annual production with well count
(data source: Dwight's Energydata, Inc.+digitized data)

Completions over the past seven years have steadily increased to 40-45 in 2010 (See Fig 17). Total completions during this time period is ~200, with the majority being in the Wantz and North Vacuum Pools of the shelf subplay.

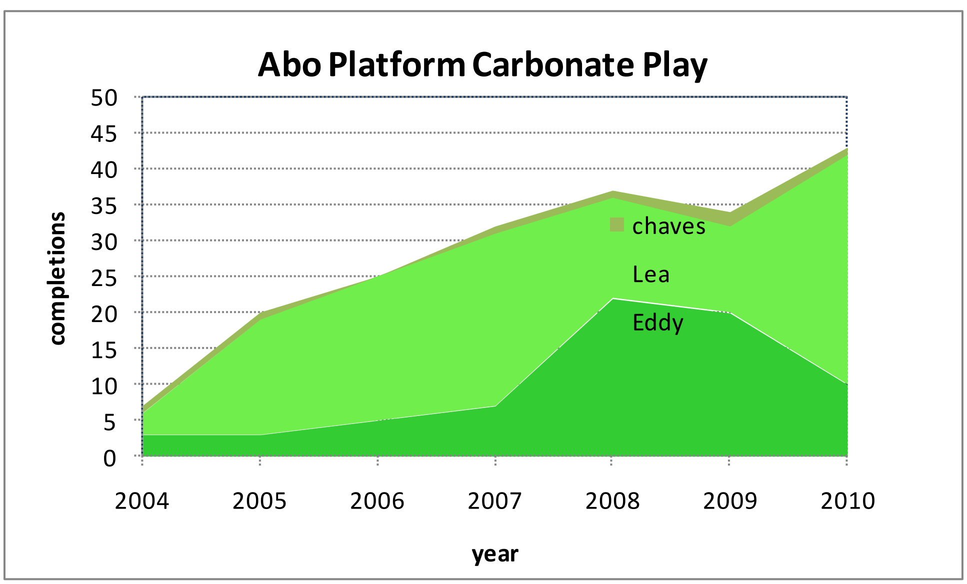


Figure 17. Abo platform carbonate completions (Source: GOTECH)

One of the more active recent pools has been the County Line Tank Abo pool which is located on the Chaves and Eddy county line. With the additional development activity, production rapidly increased to a peak of over 550 bopd for 2009 (Fig 18). Noteworthy for this field is that all wells are horizontal.

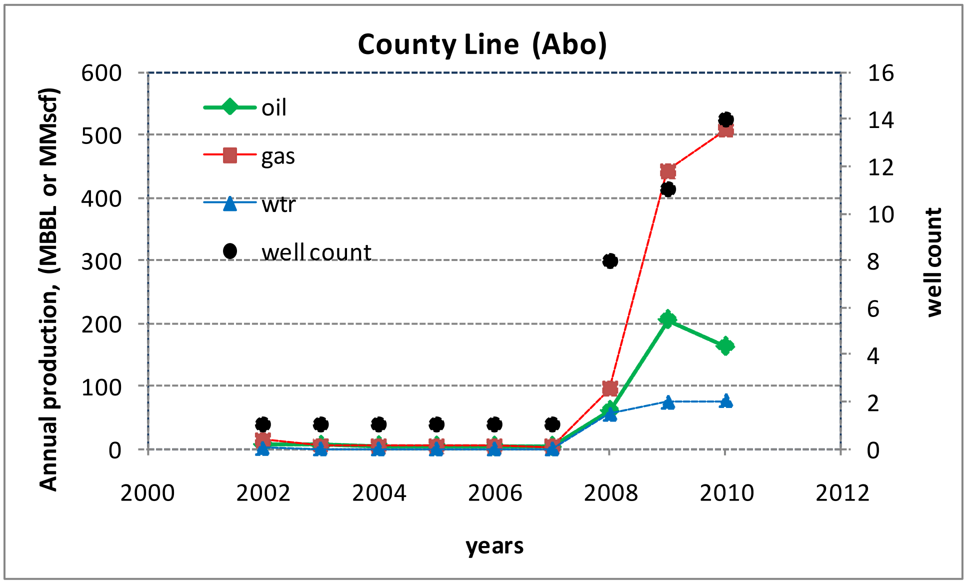


Figure 18. Annual production and well count for the County Line Tank Abo Pool. (Source: GOTECH, production through 2010)

Horizontal well performance

The Empire Abo pool was one of the earliest reservoirs to test drilling and production for a horizontal borehole. The motivation was to avoid coning gas from a significant gas cap formed as the reservoir pressure reservoir pressure fell below oil bubble point. To avoid gas coning and improve oil recovery, in the early 1980's [Joshi, 2003], the operator decided to drill 200-300ft horizontal drainholes from existing vertical wells. The comparison of performance between a horizontal drainhole and its neighboring vertical wells showed that cumulative recovery from the horizontal well was significantly better than the neighboring vertical wells. Currently, almost two-thirds of Abo completions are horizontal (Figure 19).

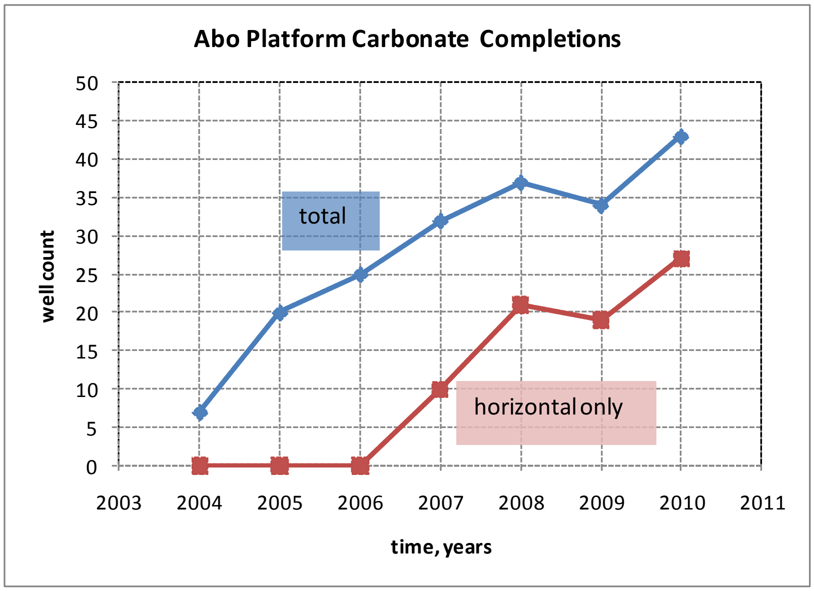


Figure 19.Total Abo annual completions and horizontal only.

Locations of the 96 horizontal wells completed in the Abo are shown in figure 20. County Line Tank Abo pool (shown in Fig 18) has the most horizontal wells at 14.

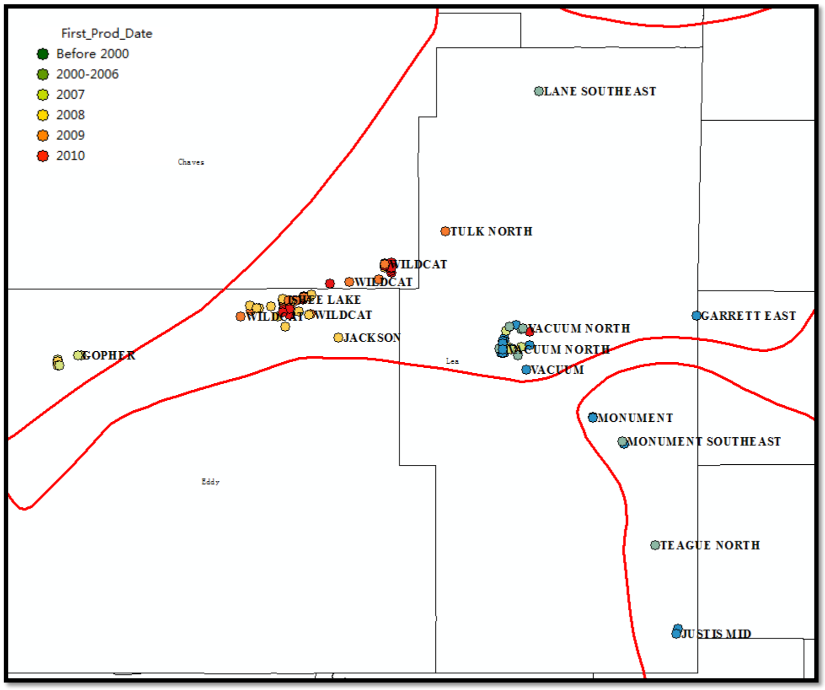


Figure 20.Location of horizontal wells in the Abo play.

Horizontal well performance has been significant; adding 1.17 MMBO to the play in 2009 (See Fig 21).

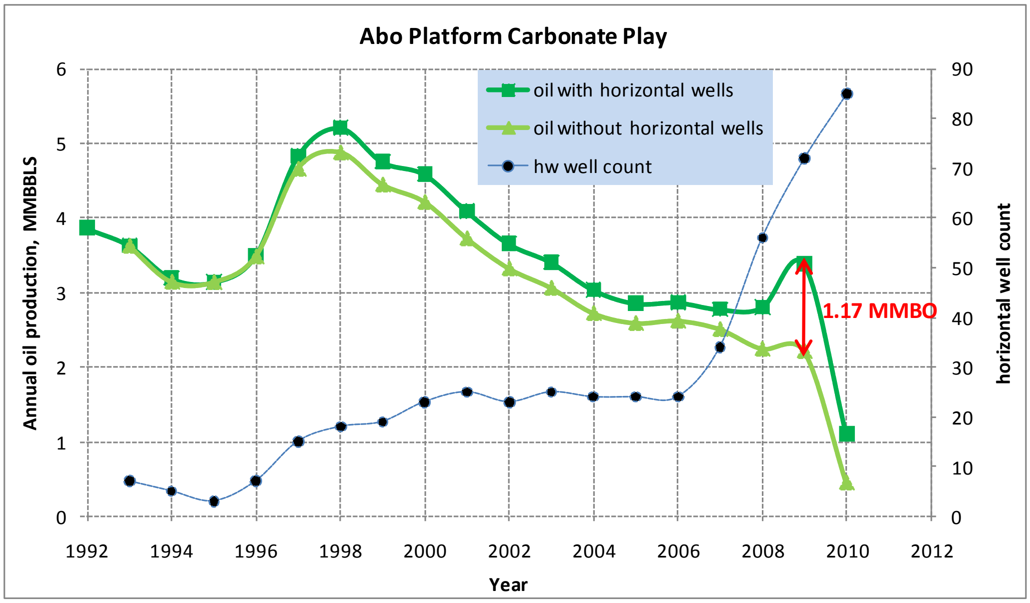


Figure 21.Performance of horizontal wells in the Abo play.

Further analysis, compared the cumulative production for the average vertical well to the average horizontal well (Figure 22). The time for all wells was normalized to time of first production; beginning with 1993. This approach compares consistent cohorts of wells and avoids the depletion effects of long producing vertical wells. The results are shown in Figure 22 for 92 horizontal wells and 413 vertical wells. Notice the horizontal wells produce 1.3 times more oil than a vertical well.

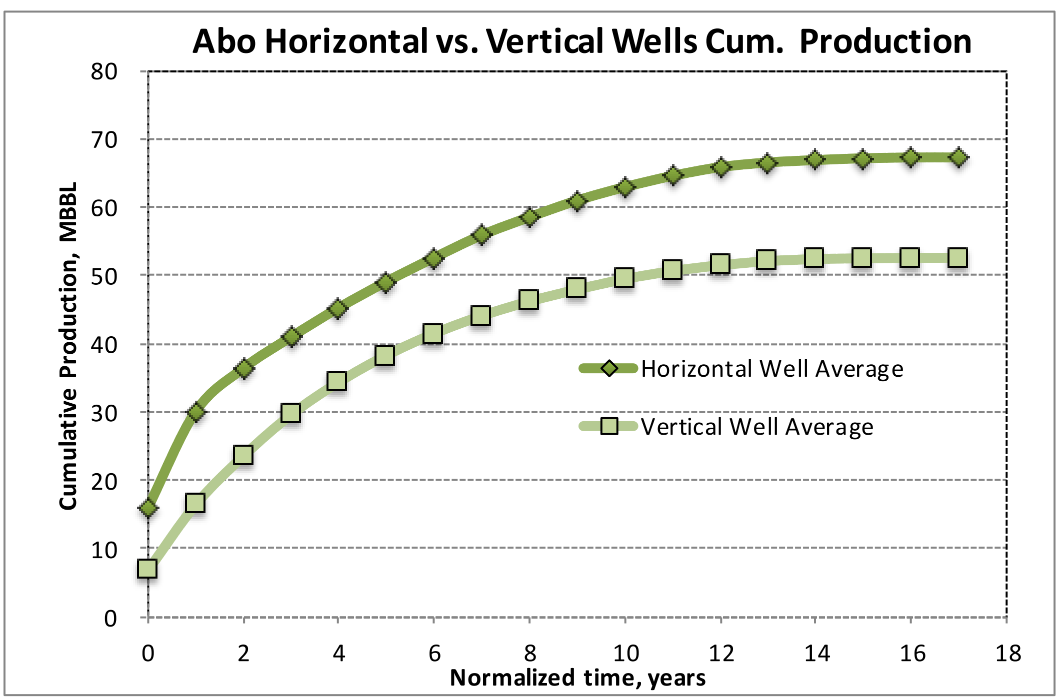


Figure 22.Comparison of average horizontal to vertical well cumulative oil production for the Abo play. (Data source: Dwights)

Water injection has occurred in the three largest Abo pools: Empire, North Vacuum and Vacuum Reef. Also, re-injection of produced gas occurred in the Empire pool. Remaining injection wells are primarily for disposal purposes (Figure 23).

Additional recovery has been linked to secondary injection. Reinjection of gas in the Empire Abo assisted the gravity drainage mechanism of the reservoir and subsequently recovered more oil. Additionally, the injection of lean gas strips the NGLs out of the remaining oil in the gas cap. In North Vacuum, waterflooding increased the ultimate production and prolonged the expected life of the field.

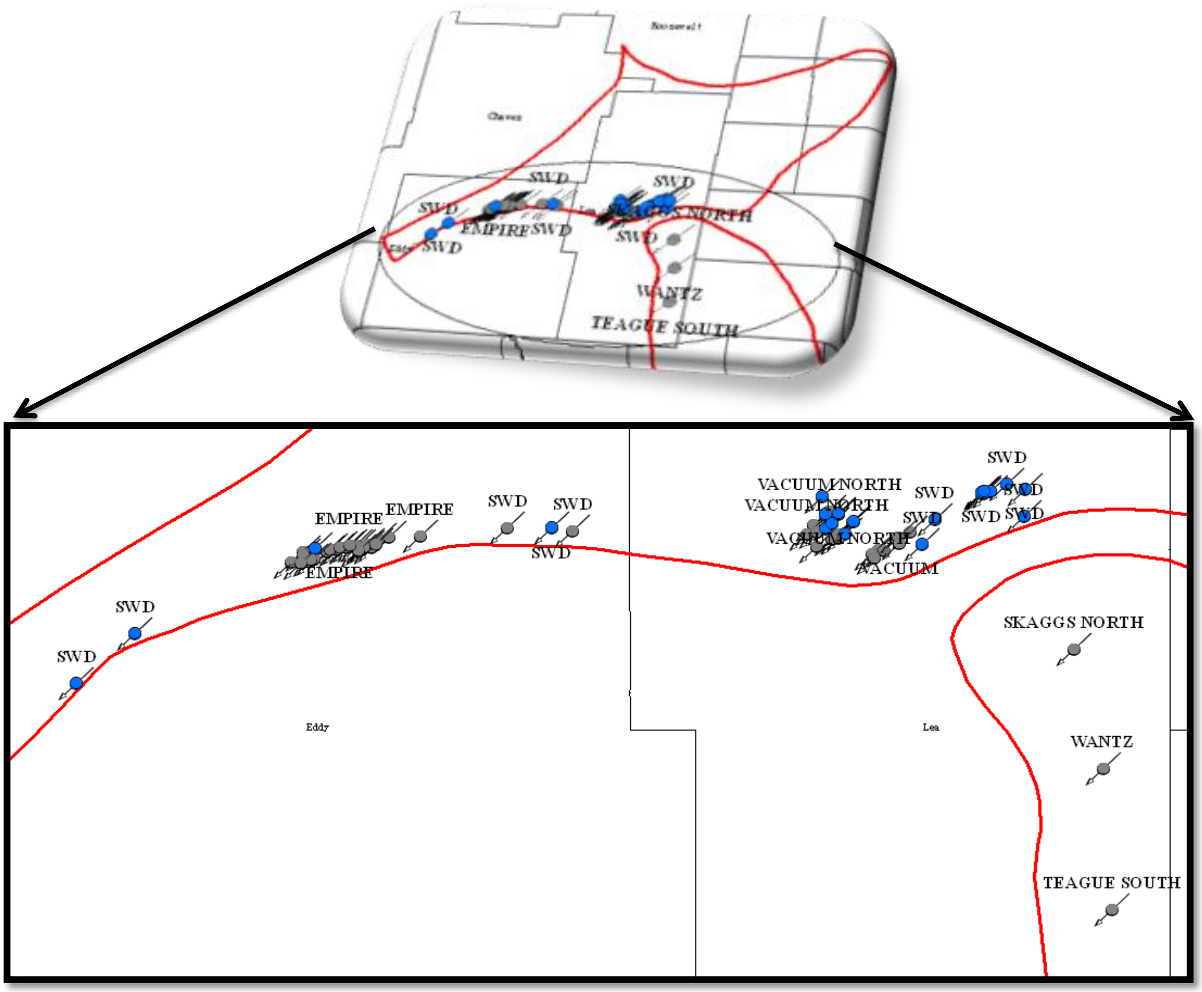


Figure 23.Location of injection wells in the Abo play.The blue symbols indicate active injection wells, and the grey ones indicate inactive injection wells. Injection wells are primarily located on the Abo Reef.

Future Development

Increasing development as observed in Figs 17 and 19 is expected to continue. Infill and replacement drilling in the major pools is one component. Approximately 50% of the completions in Fig 17 come under this category. The remaining new development will likely be horizontal wells in new areas. County Line Tank pool is an example. Figure 24 identifies the regions of moderate to high potential for this play.

CO_2-EOR potential has been identified for many Abo pools in Southeast, NM (ARI, 2006) including North Vacuum and Vacuum Abo Reef.

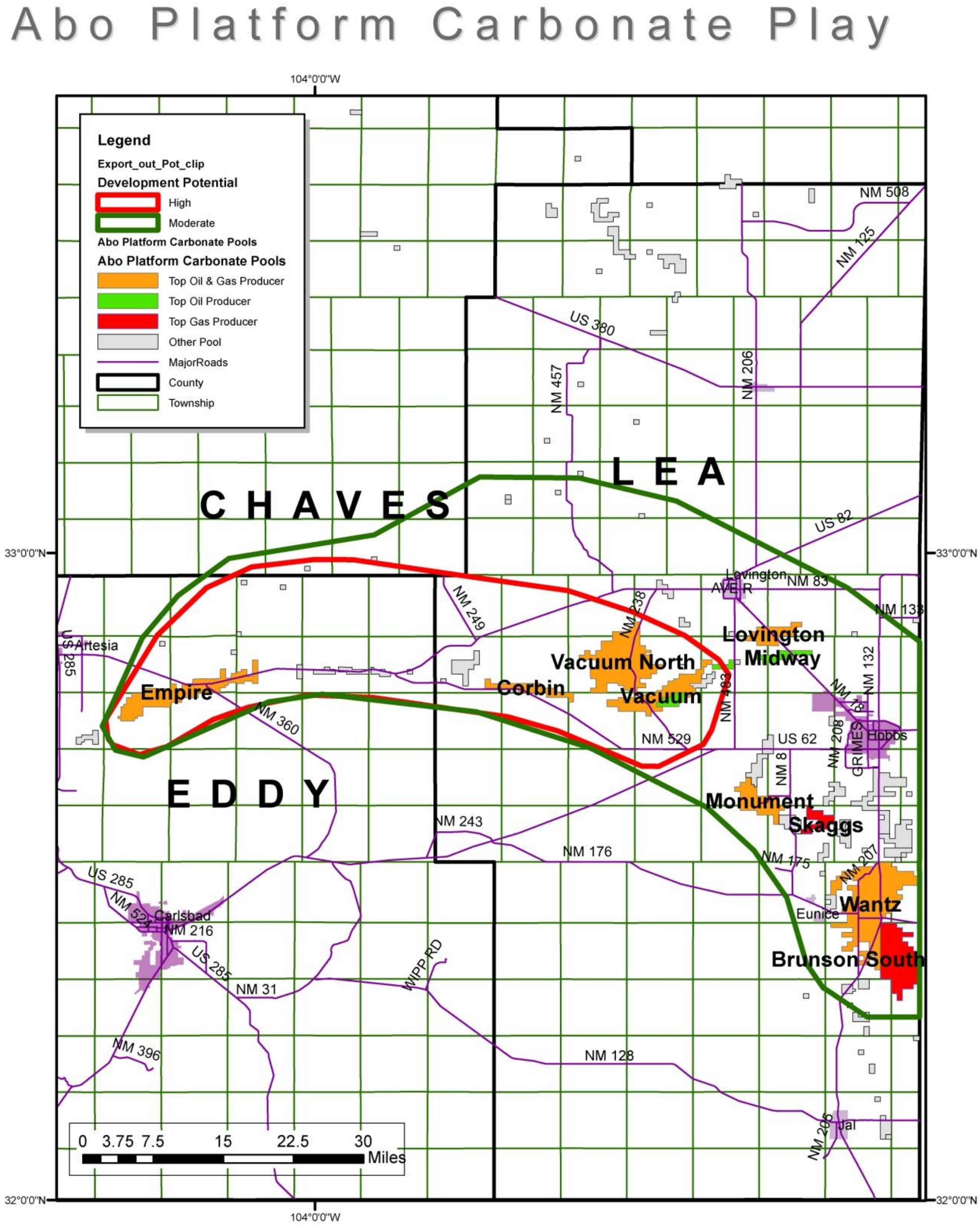


Figure 24. Pool map for the Abo platform carbonate play. Red line – high potential, green line – moderate potential.

Artesia Platform Sandstone Play

Brief Summary of Geology

Reservoirs included in the Artesia Platform sandstone play are located from the western flank of the Central Basin Platform to the Northwest Shelf of the Permian Basin (Figure 1).

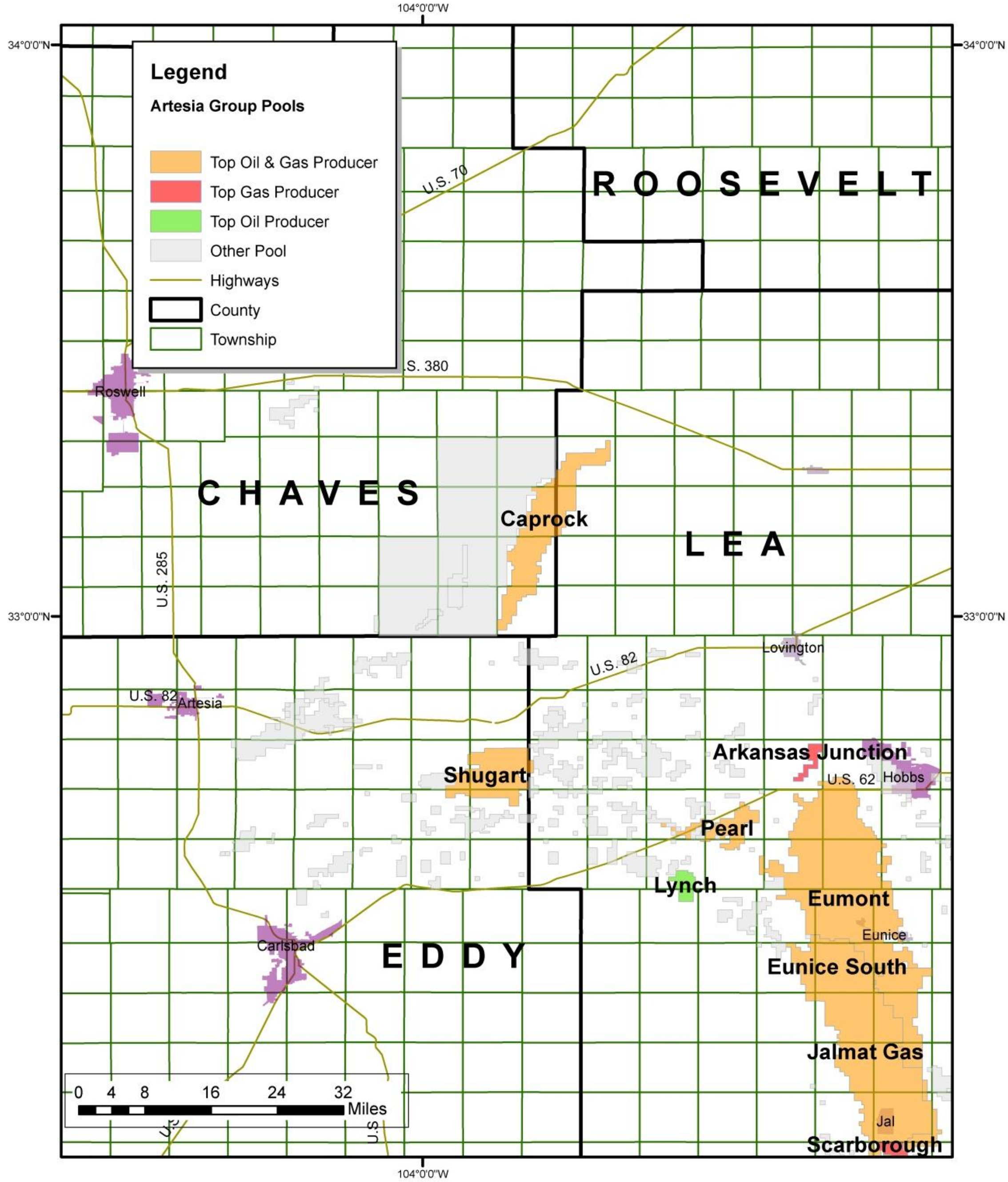


Figure 1. Major pool map for the Artesia Platform Sandstone Play.

Reservoirs within the Artesia Group are subdivided into five formations: in descending order they are the Tansill, Yates, Seven Rivers, Queen, and Grayburg (See Figure 2). Both sandstones and dolostones are productive; however the sands are more prolific and are the principal productive zones. In most cases multiple productive zones are encountered and are typically,if not always, commingled to efficiently develop these resources and prevent waste. However, along and north of the Hobbs to Artesia trend, reservoirs produce solely from Queen sandstones.

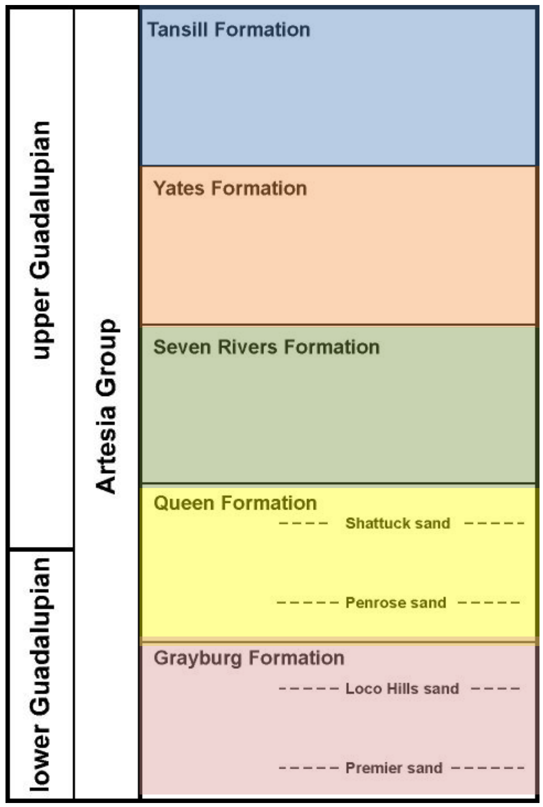


Figure 2. Strat column of the producing formations for the Artesia Sandstone Play (Broadhead, et al, 2004)

The Queen sandstones were deposited in coastal sandy braided streams, fluvial sand flats and fluvial-dominated coastal sabkhas, and poorly channelized sheet deltas that filled in lagoonal areas. Traps are largely stratigraphic, with porosity plugged in an updip direction by evaporates. (Broadhead , et al., 2004) Productive Queen sandstones are fine to medium grained; average reservoir porosities range from 17 to 22 percent and permeabilities from 1 to 50 md.

Productive Yates sandstones are poorly consolidated, silty, and fine grained with porosities of 15 to 28 percent. The sandstones occur in a clastic-rich belt on the middle shelf that separates an evaporitic inner shelf to the north from a carbonate-rich outer shelf to the south. Traps are largely stratigraphic with an updip seal formed by evaporitic facies of the inner shelf.

HISTORICAL DEVELOPMENT

Due to their shallow depth, production from sands within this play were discovered early in the history of Southeast New Mexico. Since then cumulative production for the play has been 580 MMBO, 6.15 Tscf, and 3300 MMBW. Peak production occurred in the late-1950s for both oil and gas (See figure 3). Oil and gas have steadily been declining since then with water production increasing due to water injection projects and water encroachment.

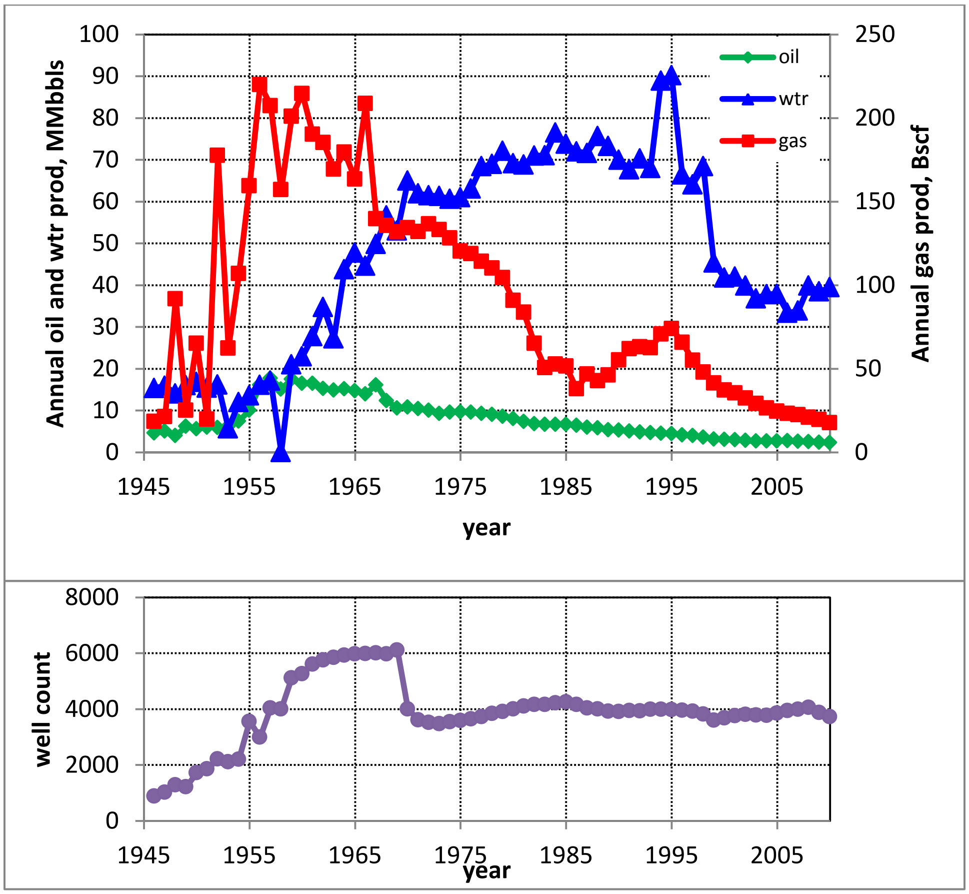


Figure 3. Annual production and well count for the Artesia Sandstone play. (Data source: digitized + Dwights)

Top oil producing pools are listed in table 1 and account for 81% of the total play's production. All of these pools have been completely or partially waterflooded in the past. The top oil producing pool is the Langlie Mattix (Seven Rivers – Queen – Grayburg) pool. Figure 4 exhibits the historical performance for this pool.

poolName	Cum_Oil MMBO	percent of total	Cumulative %	waterflood
LANGLIE MATTIX;7 RVRS Q GRAYBURG	133.7	23%	23%	Y
JALMAT;TAN-YATES-7 RVRS (all)	89.5	15%	38%	Y
CAPROCK;QUEEN	73.8	13%	51%	Y
EUMONT;YATES-7 RVRS-QUEEN (all)	48.8	8%	60%	Y
EUNICE ; SOUTH SEVEN RIVERS QUEEN	35.3	6%	66%	Y
SHUGART;YATES-7RS-QU-GRAYBURG	29.0	5%	71%	Y
PEARL;QUEEN	23.0	4%	75%	Y
LYNCH;YATES SEVEN RIVERS	16.7	3%	78%	Y
RHODES;YATES SEVEN RIVERS	14.5	2%	80%	Y
SCARBOROUGH;YATES SEVEN RIVERS	7.3	1%	81%	Y

Table 1. Top pools by cumulative oil production. (Source: digitized+dwights)

Langlie Mattax was discovered in 1929. It is one of the largest pools in this play, with over 1200 producing wells at its peak and approximately 700 producing in 2010.

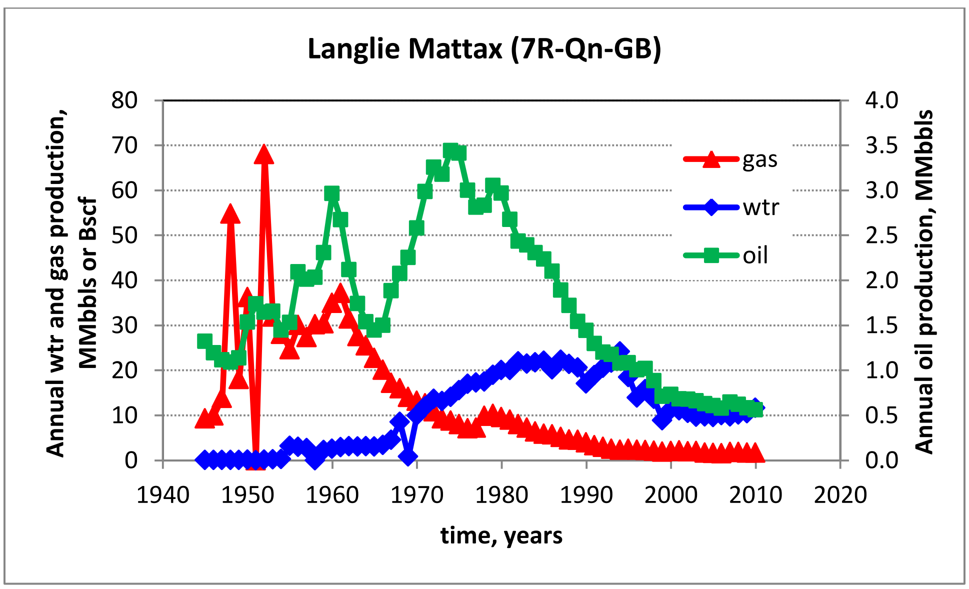


Figure 4. Annual production and well count for the Langlie Mattax pool. (Data source: digitized + Dwights)

Several of these reservoirs are oil productive while others are more gas prone and have produced significant volumes of gas. An example can be observed in the production curves for the Eumont pool in Figure 5. Approximately 2.4 Tcf has been produced from this pool; making it the top cumulative gas producing pool in the play (Table2). For more than twenty years from 1955 to 1975 annual gas production exceeded 60 Bscf per year.

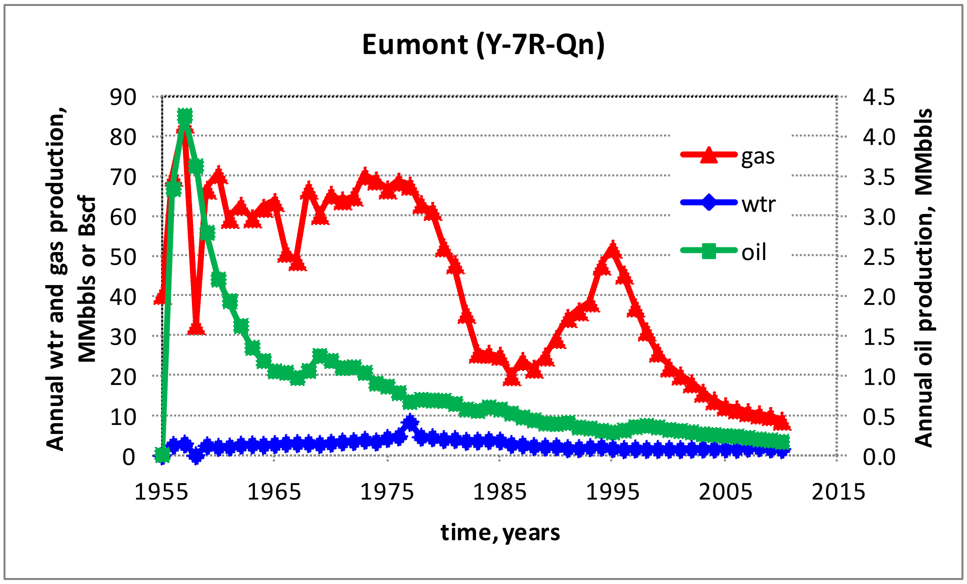


Figure 5. Annual production and well count for the Eumont pool. (Data source: digitized + Dwights)

poolName	Cum_Gas Bscf	percent of total	Cumulative %
EUMONT;YATES-7 RVRS-QUEEN (all)	2398.6	39%	39%
JALMAT;TAN-YATES-7 RVRS (all)	2028.9	33%	72%
LANGLIE MATTIX;7 RVRS Q GRAYBURG	870.9	14%	86%
EUNICE ; SOUTH SEVEN RIVERS QUEEN	318.8	5%	91%
RHODES;YATES SEVEN RIVERS	86.2	1%	93%
SHUGART;YATES-7RS-QU-GRAYBURG	16.2	0%	93%
SCARBOROUGH;YATES SEVEN RIVERS	15.5	0%	93%
CAPROCK;QUEEN	12.9	0%	94%
PEARL;QUEEN	11.4	0%	94%
ARKANSAS JUNCTION (QUEEN)	8.6	0%	94%

Table 2. Top pools by cumulative gas production. (Source: digitized+dwights)

Waterflooding has been highly successful in this play when clean sand(s) are present. Typically the Queen sand is the best quality and the likely candidate. A textbook example is the Caprock (Queen) pool shown in Figure 6. Injection commenced in 19xx, followed by the oil bank and then water breakthrough in 1965.

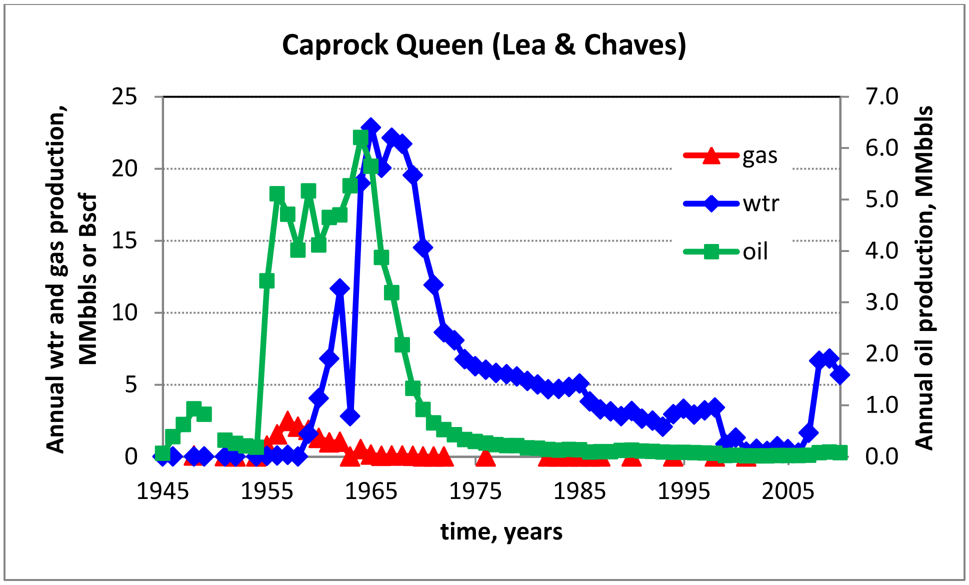


Figure 6. Waterflood response for the Caprock (Queen) Pool. (Data source: digitized + Dwights)

In the 7 year period from 2004 to 2010, 630 wells have been drilled in this play averaging 90 wells per year. The majority of wells (70%) were drilled in four pools; Jalmat, Langlie Mattax, Caprock and Eumont. Activity for these pools is shown in Table 3. Activity by year is shown in Figure 7.

Pool name	number	County
JALMAT;TANSILL-YATES-7 RVRS (OIL)	122	Lea
LANGLIE MATTIX;7 RVRS-Q-GRAYBURG	114	Lea
CAPROCK;QUEEN	66	Chaves
JALMAT;TANSILL-YATES-7 RVRS (GAS)	53	Lea
EUMONT;YATES-7 RVRS-QUEEN (GAS)	42	Lea
EUMONT;YATES-7 RVRS-QUEEN (OIL)	33	Lea

Table 3. Pools with the top activity in the period from 2004 to 2010.

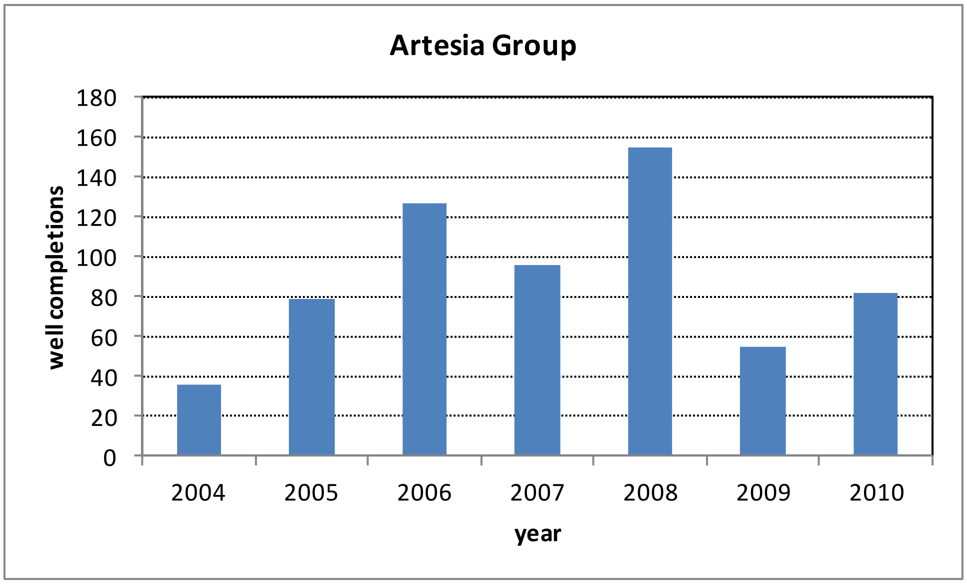


Figure 7. Recent well activity for the Artesia Group. (Data source: GOTECH)

Pools with top oil and gas production in 2010 are listed in Tables 4 and 5, respectively. Langlie Mattax and Eumont continue to be the top oil and gas pools in this play.

poolName	2010 oil rate BOPD	2010 WOR	2010 well count
LANGLIE MATTIX;7 RVRS Q GRAYBURG	1539	21	674
JALMAT;TAN-YATES-7 RVRS (all)	1104	20	708
SHUGART;YATES-7RS-QU-GRAYBURG	598	12	237
EUMONT;YATES-7 RVRS-QUEEN (all)	488	9	815
EUNICE ; SOUTH SEVEN RIVERS QUEEN	347	20	121
CAPROCK;QUEEN	202	77	47
PEARL;QUEEN	149	9	34
LYNCH;YATES SEVEN RIVERS	146	32	26
TEAS, WEST: YATES-SEVEN RIVERS	137	14	15
E-K: YATES-7 RVRS- QU	128	8	32

Table 4. Top pools by 2010 oil production rate. (Source:GOTECH)

poolName	2010 gas rate MCFD	2010 Well
EUMONT;YATES-7 RVRS-QUEEN (all)	24267	815
JALMAT;TAN-YATES-7 RVRS (all)	14026	708
LANGLIE MATTIX;7 RVRS Q GRAYBURG	4599	674
EUNICE ; SOUTH SEVEN RIVERS QUEEN	1100	121
BYERS (QUEEN)	862	7
RHODES;YATES SEVEN RIVERS	831	110
TONTO (SEVEN RIVERS)	361	39
ARKANSAS JUNCTION (QUEEN)	257	3
BOWERS (SEVEN RIVERS)	207	11
HACKBERRY, NORTH (YATES-7 RVRS)	190	4

Table 5. Top pools by 2010 gas production rate. (Source:GOTECH)

PREDICTED DEVELOPMENT

A moderate potential of future development is anticipated for this play; primarily as continued replacement drilling, infill drilling and some extension in the major pools. Replacement drilling is viable due to the age of existing wells and application of advanced technologies in new completions. Infill drilling is also viable for the reasons cited above.

The reservoirs included in this play are not good candidates for horizontal wells due to their shallow depth and arrangement as multiple, stacked pay zones.

When clean sand is present, waterflood response has been excellent. For this reason, CO2 – EOR has been proposed as a viable future alternative for pools in this play. From the ARI (2006) study, Caprock (Queen) ,Dollarhide (Queen), South Eunice (Seven Rivers – Queen), Langlie Mattax (7 RVRS-QN-GB), and Pearl (Queen)have all been identified with EOR-CO2 potential. With other better candidates for EOR-CO2 in Southeast New Mexico, development will be delayed for many years.

Atoka & Atoka Morrow Play

The potential for future development is strongly dependent upon natural gas prices and therefore is in the ***low to moderate*** range. Based on the EIA predictions for gas prices, only a slight increase is seen in the next 25 years. Consequently, only limited gas development is forecasted.

BRIEF SUMMARY OF GEOLOGY

Of the 260+ designated reservoirs that produce gas from Atokan age rocks, 25 have produced at least 10 BCF. All reservoirs pr oduce nonassociated gas with varying amounts of condensate and are either in the Delaware Basin or near its margin on the Northwest shelf (Fig. 1). Atoka reservoirs are Pennsylvanian in age in both Delaware Basin and Northwest shelf. (Fig. 2)[Broadhead, et al., 2004]

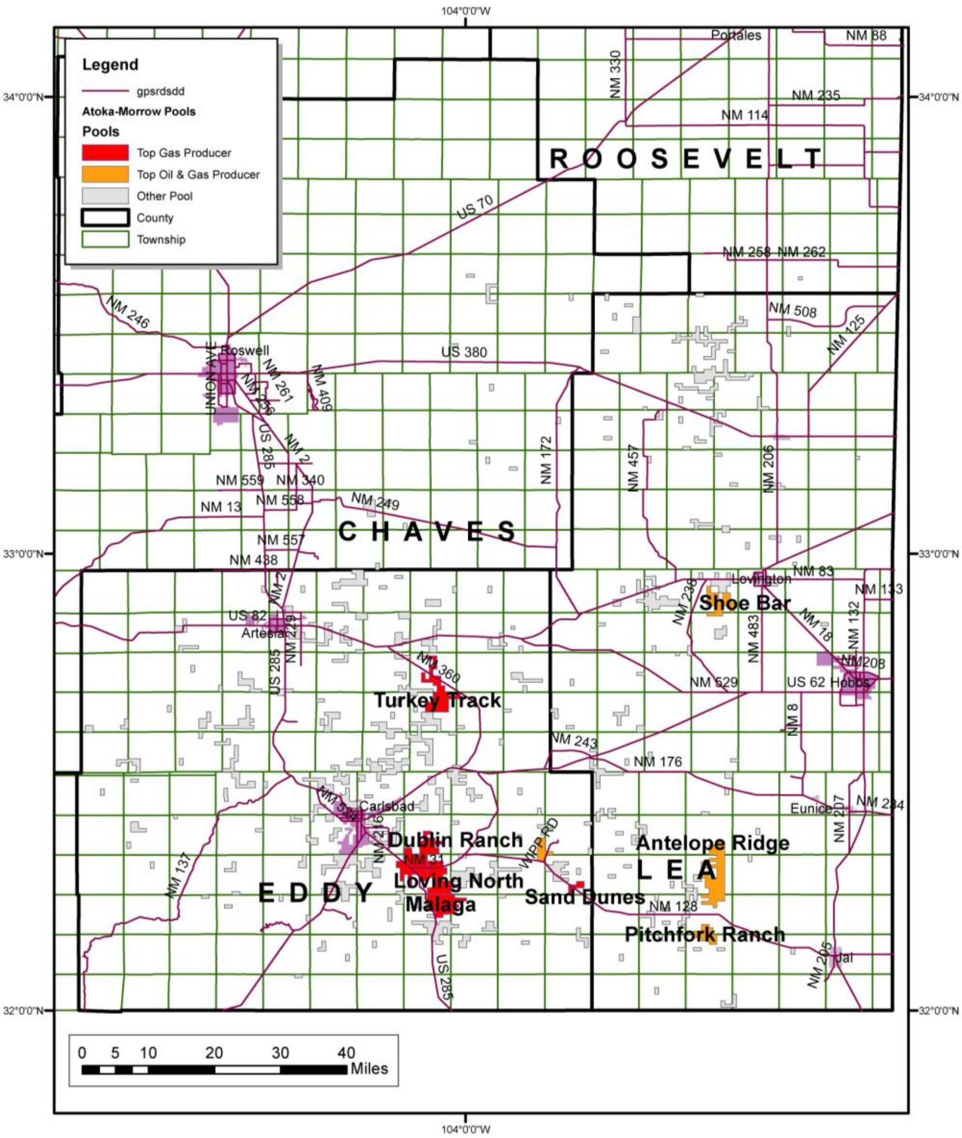


Fig.1 Location of major reservoirs in the Atoka play

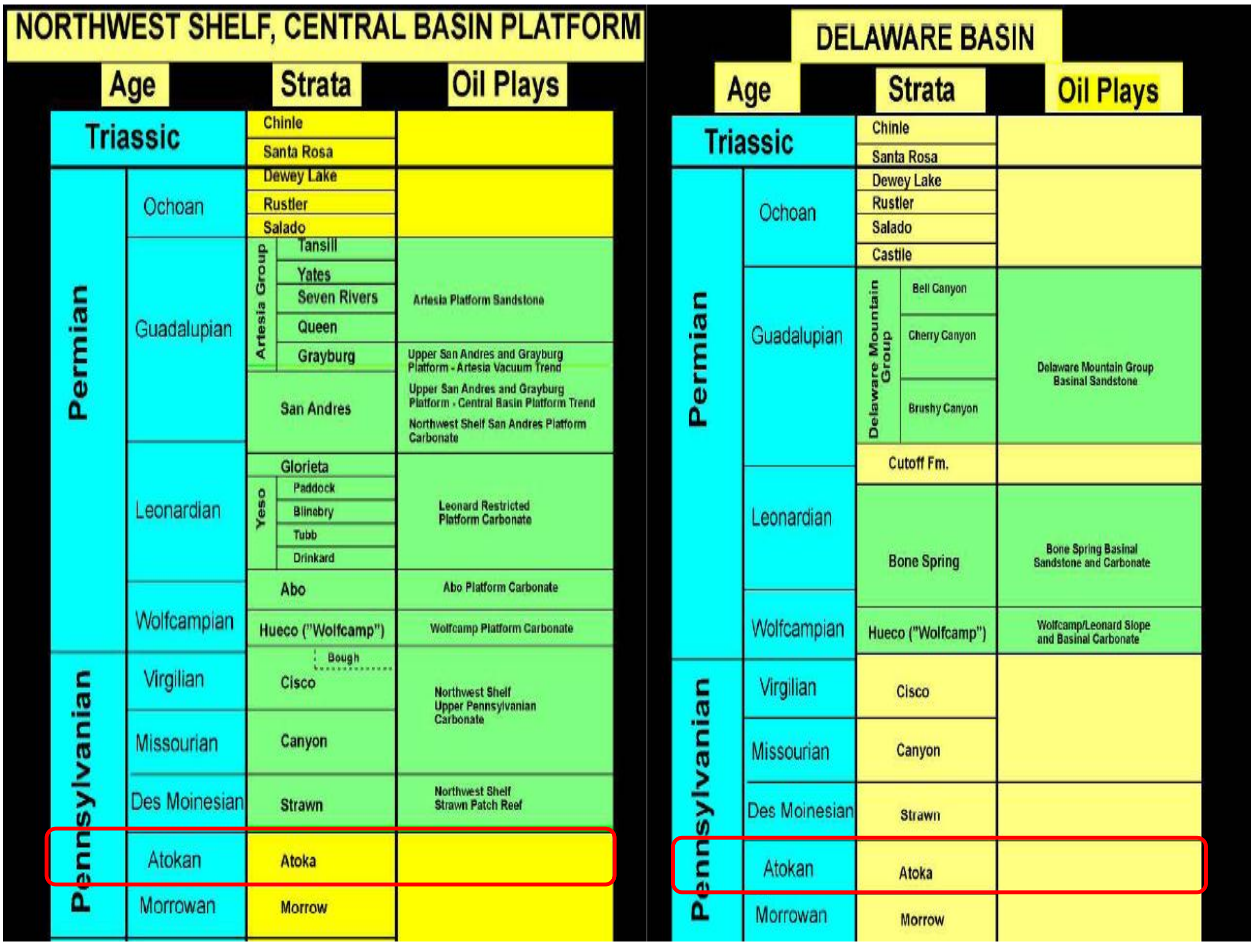


Fig. 2 Stratigraphic chart showing relationship of Atoka play on the Northwest Shelf and Delaware Basin [Broadhead, et al., 2004].

Reservoirs can be found at depths ranging from 8,500 ft on the Northwest shelf, to more than 14,000 ft in the Delaware Basin. Production is generally obtained from fluvial-deltaic and prograding strandline (beach and barrier bar) sandstones derived primarily from the Pedernal Highlands to the northwest, although a bank of carbonate mounds in south Lea and Eddy counties also contributes significantly to production. Clastic reservoirs commonly consist of multiple, fine to coarse grained quartzose sands with net pay thicknesses ranging from 5 to more than 40 ft.

Porosity of productive sandstones range from 2% to as much as 16%, they more commonly average 10% with permeability running in the tens of millidarcies. Reservoirs of limited extent are common in the Atoka and trapping generally occurs by a combination of structural and stratigraphic mechanisms. Fig. 3 illustrates the overall depositional environment for Atokan siliciclastics proposed by James [1985]. Many of the deeper Atoka reservoirs are significantly overpressured (up to 10,571 psi at a 0.76 pressure gradient) and require additional casing strings and high mud weights to ensure successful drilling operations.[Worthington,1999].

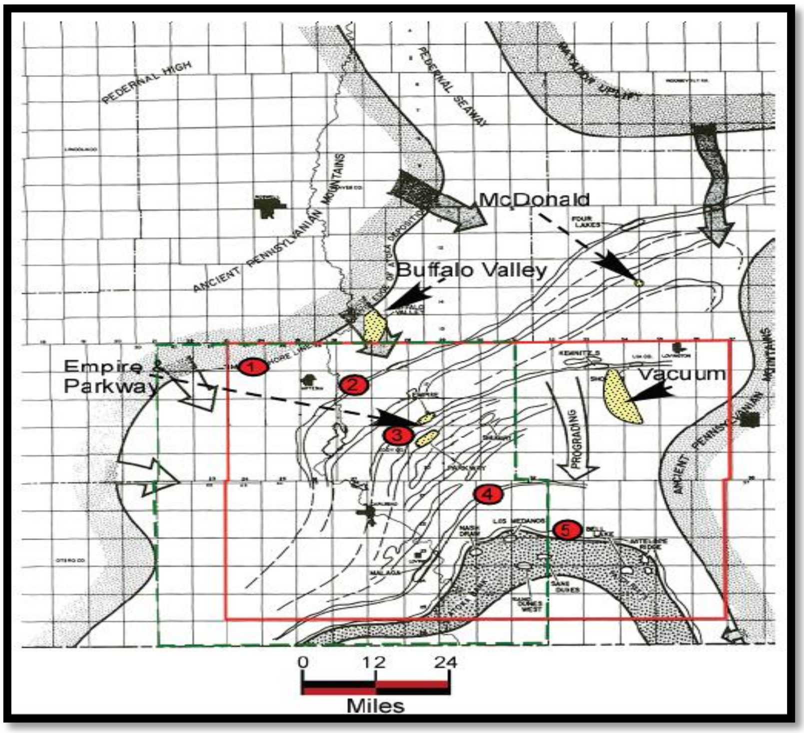


Fig. 3 Atokan-age depositional paleogeography for the north Delaware Basin and Northwest Shelf (from James, 1985).

James [1985] interpreted the shoreline position to step basinward through time from 1 (oldest) to 5 (youngest). It is alternatively possible that shelf ridges or barrier bars formed during transgression and are younger updip (oldest at shoreline, 5 and youngest at 1). Note the need for an eastern source area for Vacuum field coarse valley-fill sediments because it is isolated from the Pedernal High to the northwest. [Wright]

HISTORICAL DEVELOPMENT

As shown in Figure 1, the Atoka play has been dominantly gas productive. As of August 2010, the Atoka Play has produced 10 MMBO oil and 965 BCF gas. There are 262 designated reservoirs totally, of which 25 have produced at least 10 BCF gas.

Gas production from Pennsylvanian Atoka sandstones was first established in 1956 but not extensively developed until the “boom” years of 1977 through 1984 when gas demand was high and markets were favorable. Drilling activity continued into the 80’s, although was a slower rate [RGS, 1999]. After 1990, however, the gas production and oil production became declining. In 2001, the gas and oil production were only the half of 1990’s. The second production peak of Atoka play came after 2003, with extensive infill and extension drilling. The number of producing wells increased from 305 in 2001 to 487 in 2009 (Fig. 4).

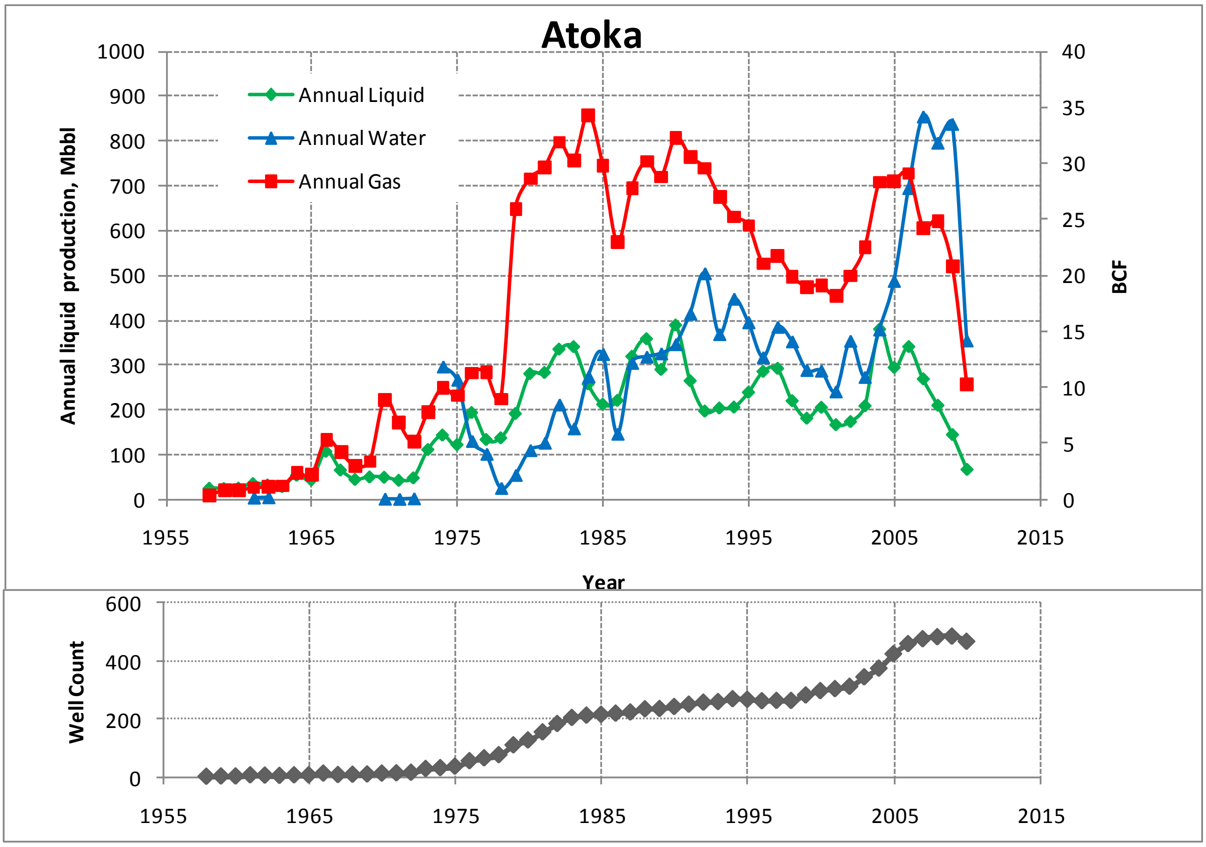


Fig. 4 Historical production and well count for the Atoka play [source: Annual Report of the New Mexico Oil & Gas Engineering Committee (prior to 1970) and Dwight's Energydata, Inc. from 1970 to present]

The top oil and gas producing pools are shown in Figure 5 and tables 1 and 2, respectively.

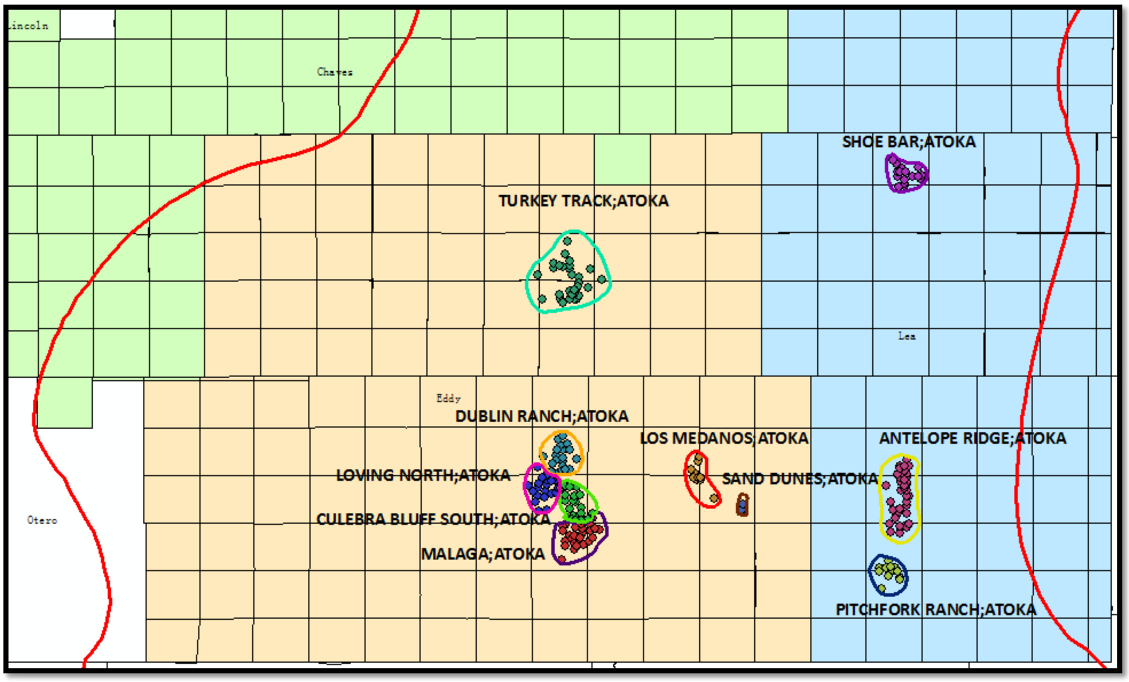


Figure 5. Top Atoka producing pools

Pool Name	Cum_gas(BCF)	percent	Cum %
ANTELOPE RIDGE;ATOKA	108.90	11.28%	11.28%
CULEBRA BLUFF SOUTH;ATOKA	64.95	6.73%	18.02%
LOS MEDANOS;ATOKA	56.65	5.87%	23.89%
MALAGA;ATOKA	53.14	5.51%	29.39%
LOVING NORTH;ATOKA	34.13	3.54%	32.93%
PITCHFORK RANCH;ATOKA	33.55	3.48%	36.41%
TURKEY TRACK;ATOKA	30.97	3.21%	39.62%
SHOE BAR;ATOKA	27.65	2.87%	42.48%
DUBLIN RANCH;ATOKA	25.55	2.65%	45.13%
SAND DUNES;ATOKA	25.19	2.61%	47.74%
Cumulative Gas Production	460.69		
Total Atoka Field	965.01		

Table 1. Top gas producing reservoirs in the Atoka play as August, 2010.

Pool Name	Cum_Oil(MBBLS)	percent	Cum %
ANTELOPE RIDGE;ATOKA	2302.41	22.82%	22.82%
PITCHFORK RANCH;ATOKA	522.77	5.18%	28.00%
GRAYBURG;ATOKA	514.31	5.10%	33.10%
LOS MEDANOS;ATOKA	405.04	4.01%	37.11%
SHUGART NORTH;ATOKA	270.99	2.69%	39.80%
SAND SPRINGS;ATOKA	233.70	2.32%	42.11%
TONTO;ATOKA	219.50	2.18%	44.29%
HENSHAW;ATOKA	213.96	2.12%	46.41%
SHOE BAR;ATOKA	212.29	2.10%	48.51%
LUSK SOUTHEAST;ATOKA	207.25	2.05%	50.56%
Cumulative Oil Production	5102.21		
Total Atoka Field	10090.50		

Table 2. Top oil producing reservoirs in the Atoka play as August, 2010

The top ten pools only account for approximately half of the total production from the Atoka. This indicates production is evenly distributed among many pools. Antelope Ridge is the most productive reservoir of Atoka play, with cumulative production of 2.3 MMBO and 108.9 BCF. The historical production curves for Antelope Ridge are shown in Figure 6.

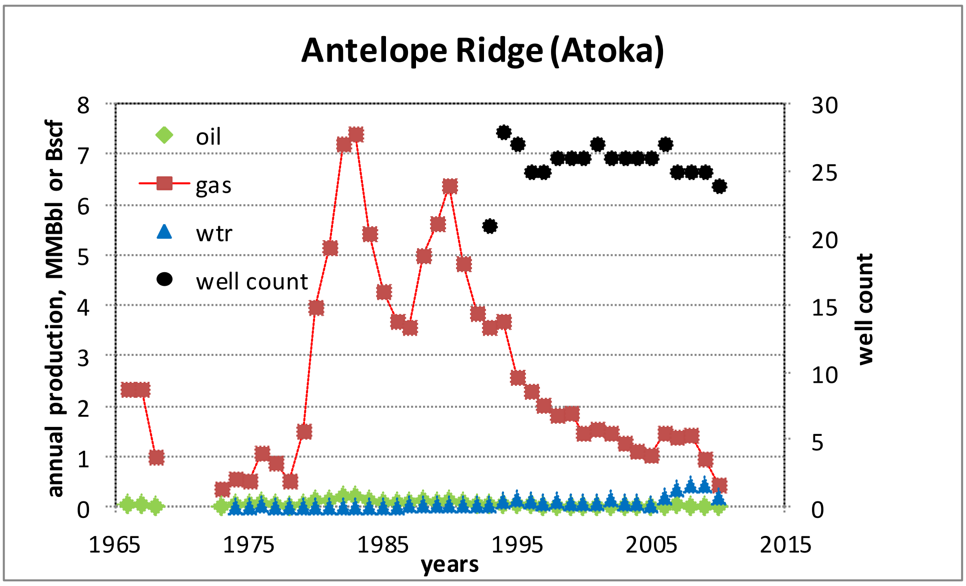


Fig. 6 Annual oil production and well count for Antelope Ridge (Atoka) Pool.
(Source: digitized data and Dwights Energydata, Inc.)

Recent activity in the Atoka and Atoka-Morrow gas plays is shown in Figure 7. Within the past seven years, completions peaked in 2005 and have been steadily declining in response to falling natural gas prices. Approximately 265 wells were completed in these gas plays over that timeframe.

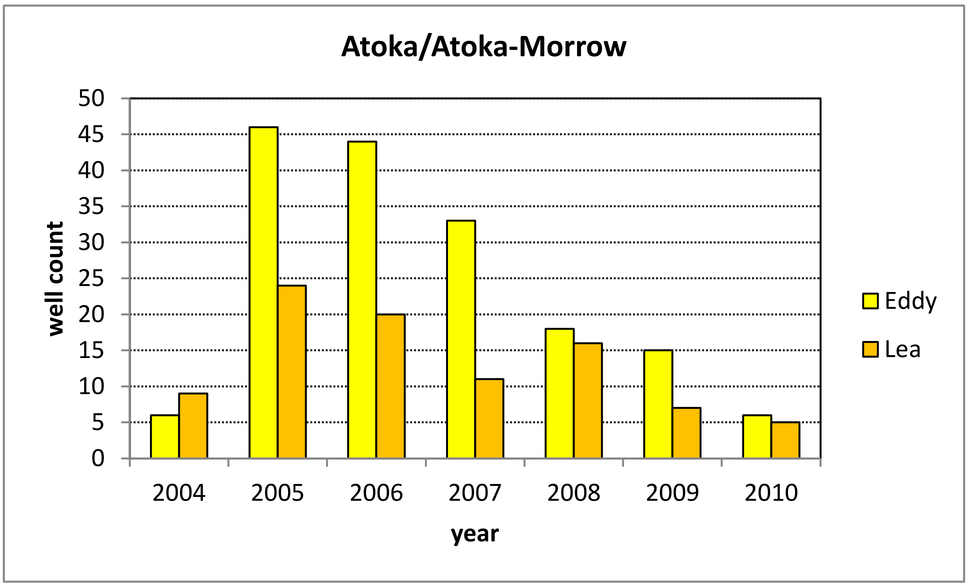


Fig 7. Recent annual completions in the Atoka and Atoka-Morrow plays in Lea and Eddy Counties.

This activity for the Atoka can be seen spatially in Figure 8. The majority of new wells are located in central & northern Eddy County and the northern & southern portions of Lea County.

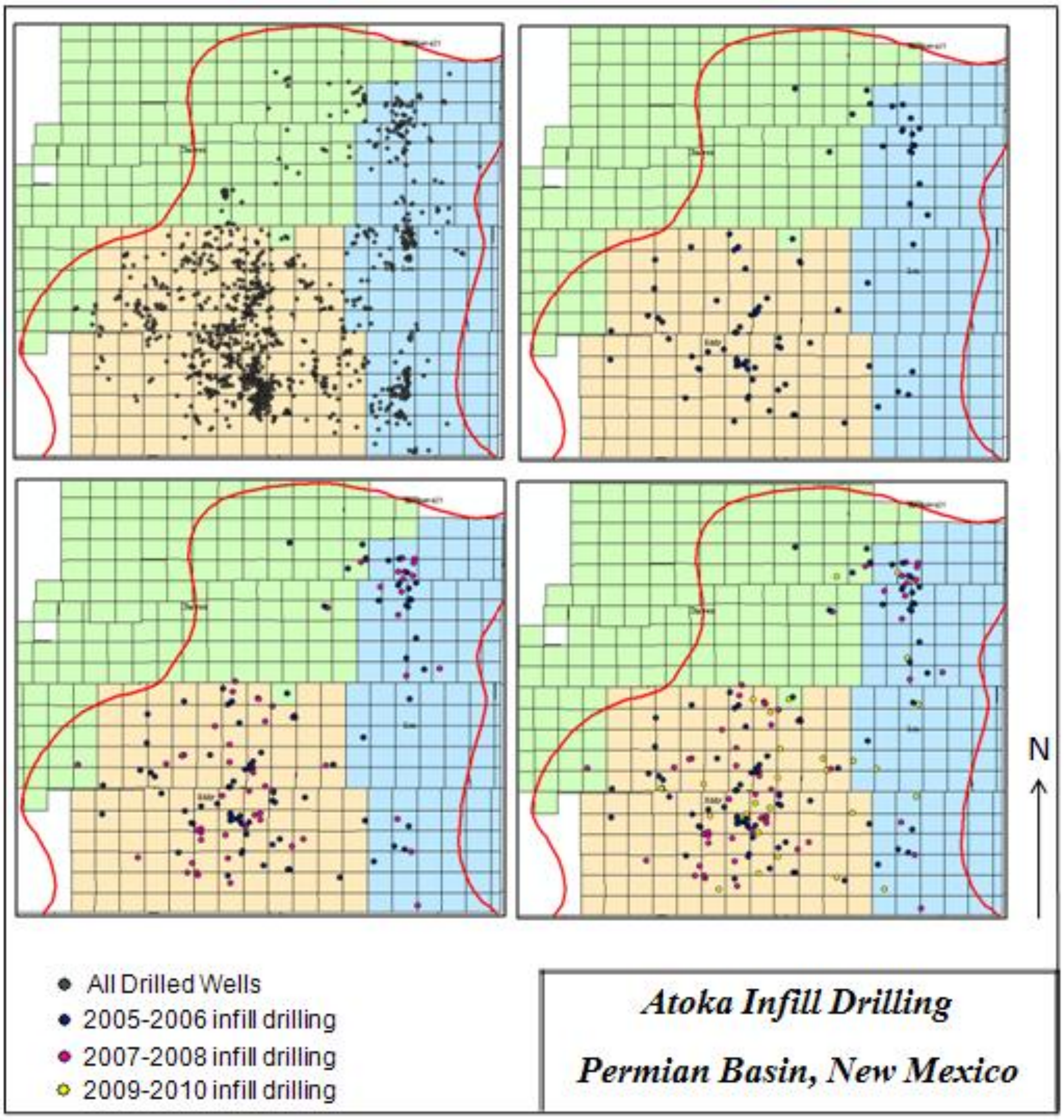


Fig. 8 Atoka play activity trend (Data Source: Dwights Energydata, Inc.)

A significant number of these completions can be attributed to renewed (infill and/or stepout drilling) development in existing fields. An example is the Dublin Ranch (Atoka) Pool shown in Figure 9. Within a 6 year time span (2002 to 2008) annual gas production increased 1147% (0.2 to 2.3 Bcf) and simultaneously the well count increased 50% (8 to 12). The map in Figure 9 shows the location of development has been northward.

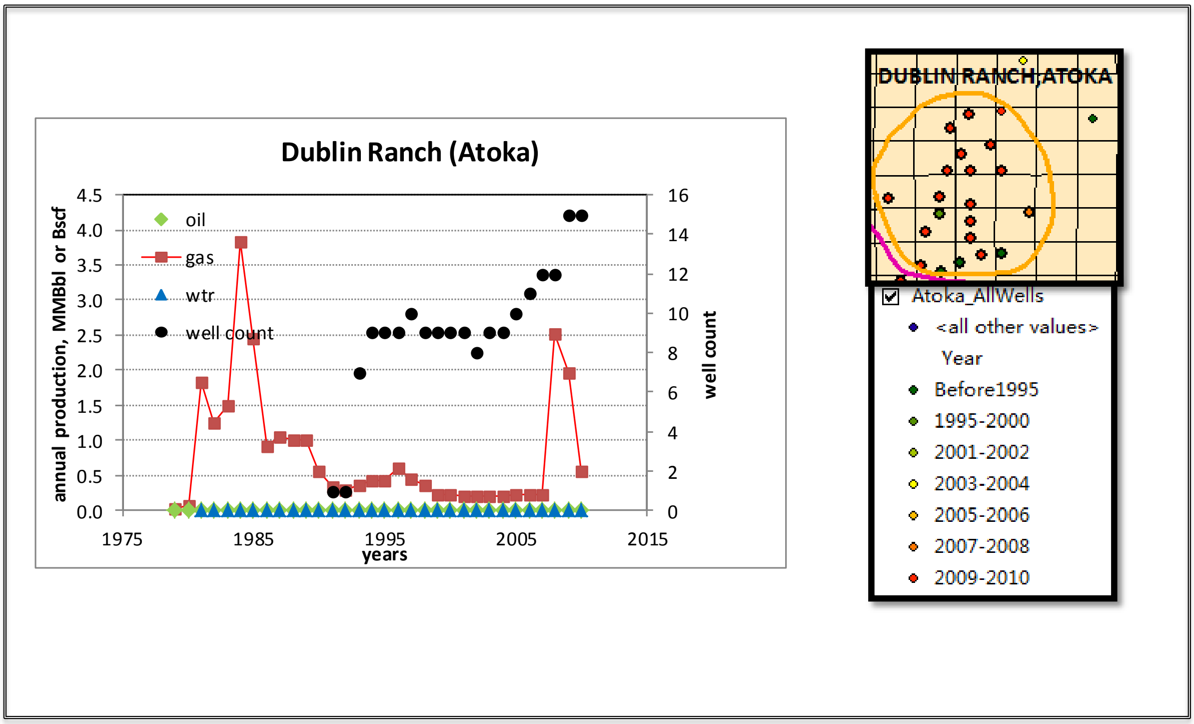


Fig 9. Annual production and well count for Dublin Ranch (Atoka) Pool and location map of wells coded to the date of first production. (Data Source: Dwights Energydata, Inc.)

Only four horizontal wells have been drilled in the Atoka since 2001, all in Eddy County (Fig. 10).

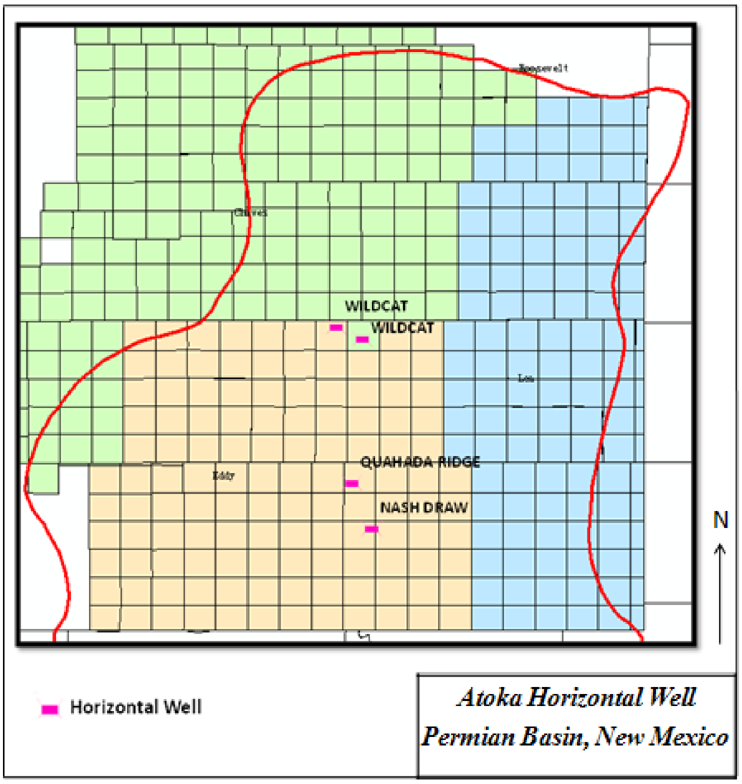


Fig. 10 Location of Horizontal wells in the Atoka play. (Data Source: Dwights Energydata, Inc.)

A comparison of the cumulative production of the horizontal wells in the Atoka to conventional vertical wells is shown in figure 11. The time scale for all wells in fig 11 has been shifted such that first production begins at time zero. In this way we are comparing first year production for all wells and so on. The vertical well curve is the average of 361 vertical wells completed in the Atoka since 2001, the year of the first horizontal well. Observe half of the horizontal wells did better than the vertical well average, while the remaining half did not. Unfortunately the sample set is small and therefore statistics are not representative.

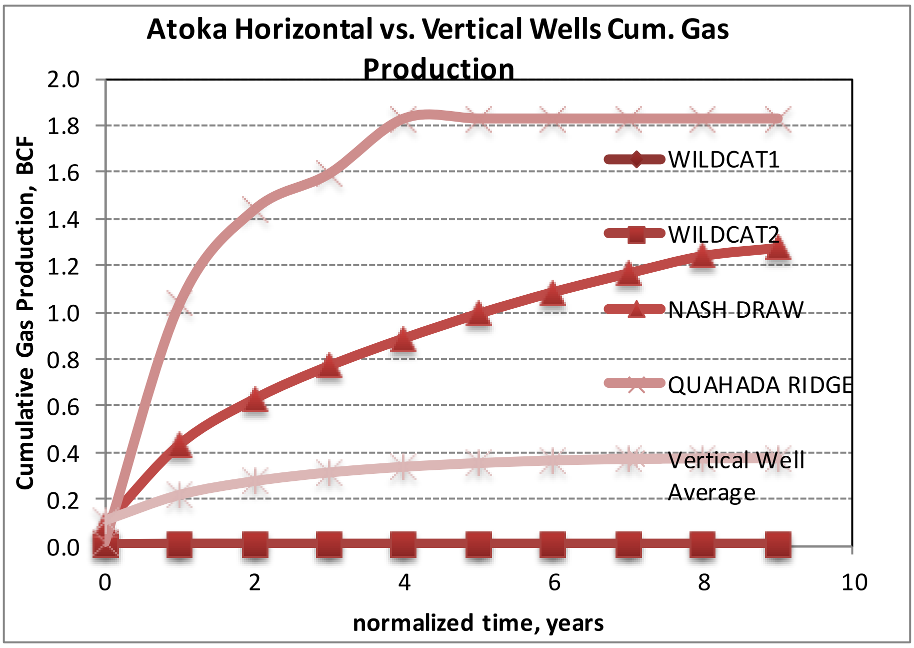


Fig. 11 Production of horizontal wells from Atoka Play

Predicted Development

Additional infill/stepout locations are available in a number of the Atoka Pools. Figure 12 displays the Atoka reservoirs with high potential based on their recent successful activity. As an example, in the Dublin Ranch pool (Fig 9) approximately 30 160-acre locations are within the pool boundary outlined in orange on the figure. Other pools have similar opportunities; however, the current low natural gas prices have significantly reduced this development (See Fig 7). Since projections for natural gas prices are too remain relatively constant, there is no economic incentive to develop these gas pools. As a result predicted Atoka completions will remain low.

Too few horizontal wells have tested the Atoka and those that have, the results are mixed. Due to the depth, complex reservoir and natural gas prices, horizontal wells are not predicted to be significant.

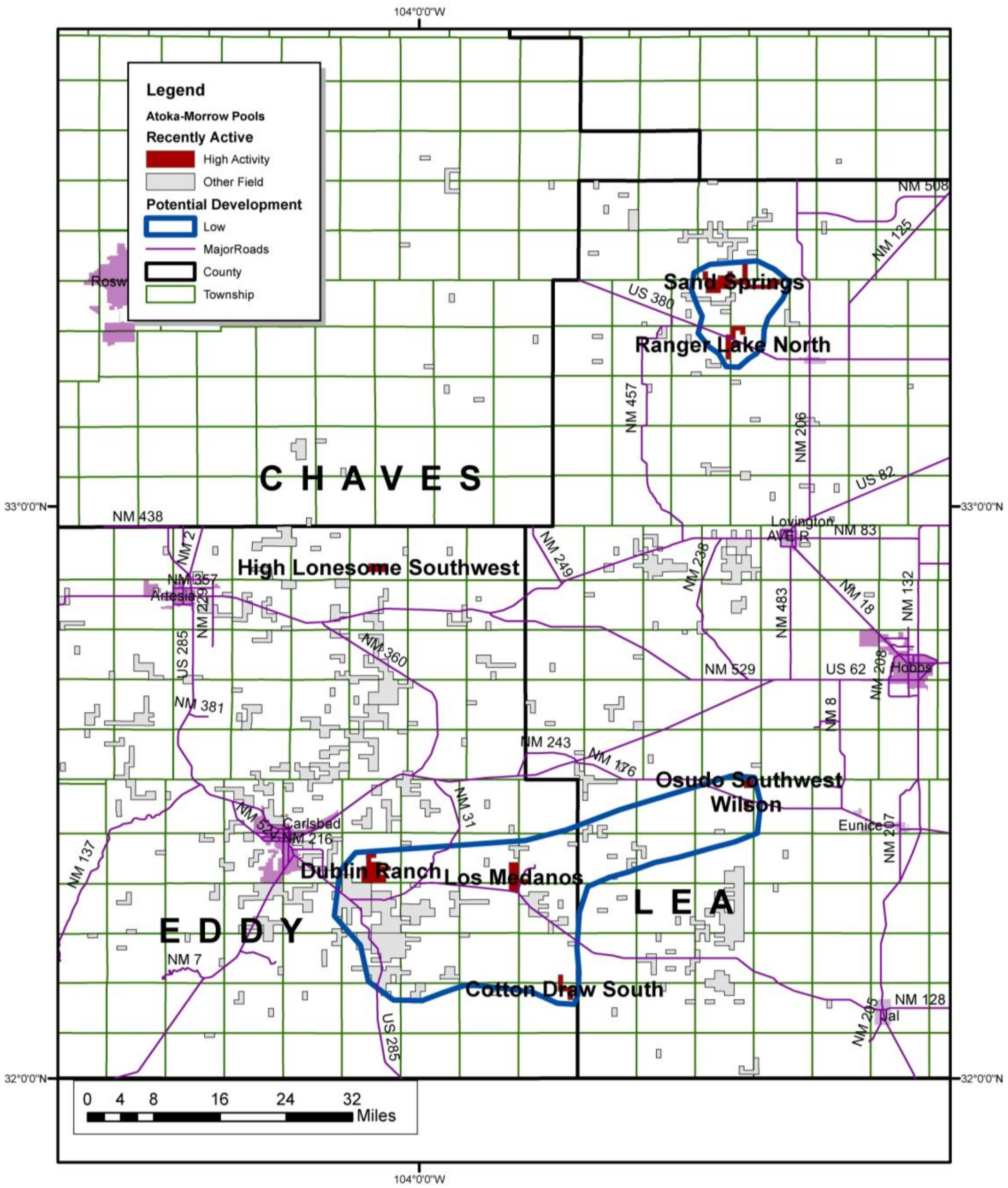


Fig. 12 The location of best potential reservoirs in the Atoka Play

Bone Spring Basinal Sandstone and Carbonate Play

The predicted potential for the Bone Spring play is ***very high***.

BRIEF SUMMARY OF GEOLOGY

The Bone Spring formation consist of alternating three main carbonate and three classic (sand) intervals deposited along the shelf and basin slopes of the Abo-Yeso shelf edges (Figs 1 and 2). The entire formation is Leonardian in age and consists of up to 3500 ft. in gross thickness (Bruce, H. 1997). The alternating carbonate and sandstone intervals are commonly referred to from top to bottom as first, second and third Carbonate (or sandstone) intervals. Recent drilling and field reevaluation identified a fourth significant sandstone interval above the first Bone Spring sandstone, named the Avalon sandstone (Fig 3).

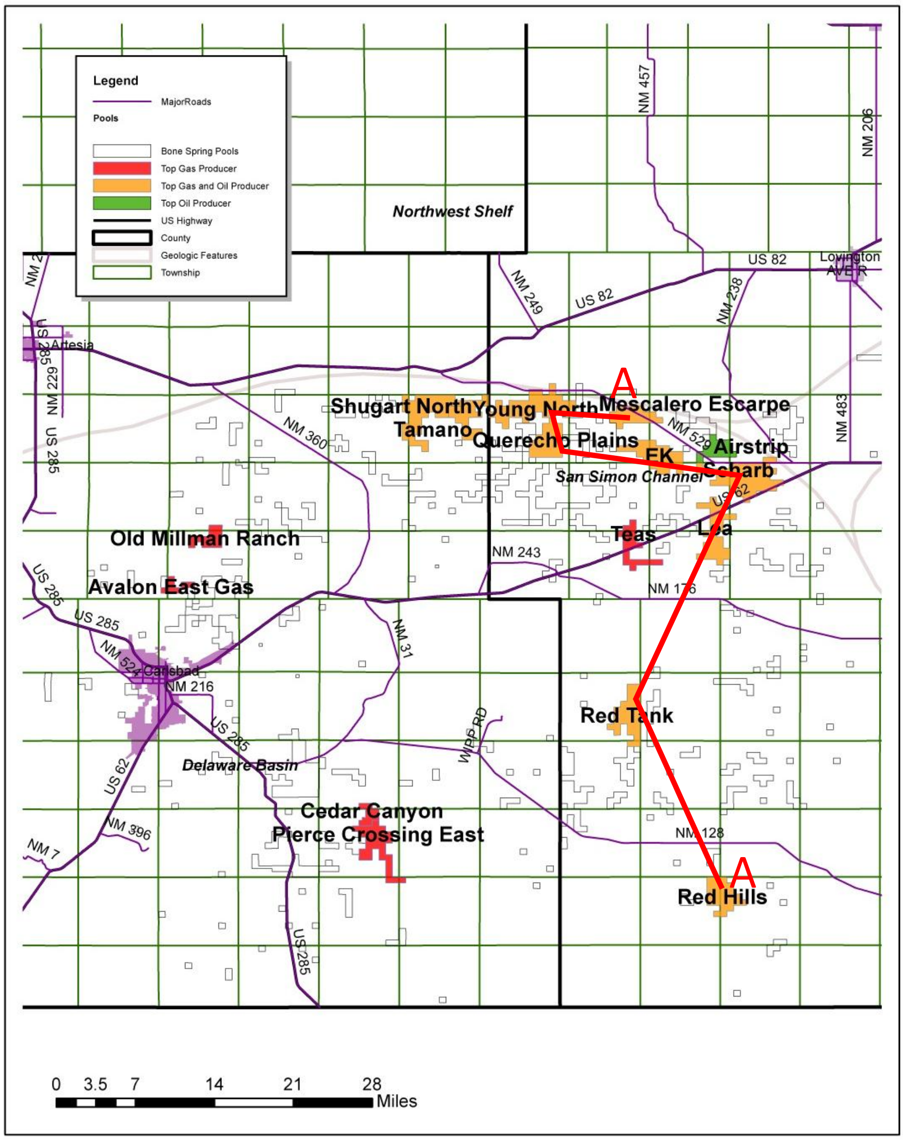


Figure 1 Location of Bone Spring pools.

The productive carbonate reservoirs of the formation are localized in the updip pinchout lenses of the porous and permeable second and third carbonate detrital intervals basinward of the Abo-Yeso shelf edge (Gawloski, 1987). Rocks are megabreccia or conglomerates debris. The second and third carbonates rocks have undergone extensive dolomitization and dissolution of skeletal grains and calcite as well as silica cementation. They exhibit excellent secondary porosity (Gawloski, 1987) typically showing moldic, vugular, interparticle, intercrystalline, fracture and solution enlarged fractures pores. Traps are mostly stratigraphic with many updip pinch outs. Other traps are diagenetic with porous and permeable dolomite reservoirs abruptly changing laterally to non-porous limestone or dolomitic mudstone-siltstone horizons. Initial potential rates of carbonate reservoirs range up to 1500BOPD and per well potential exceed 1MM barrels.

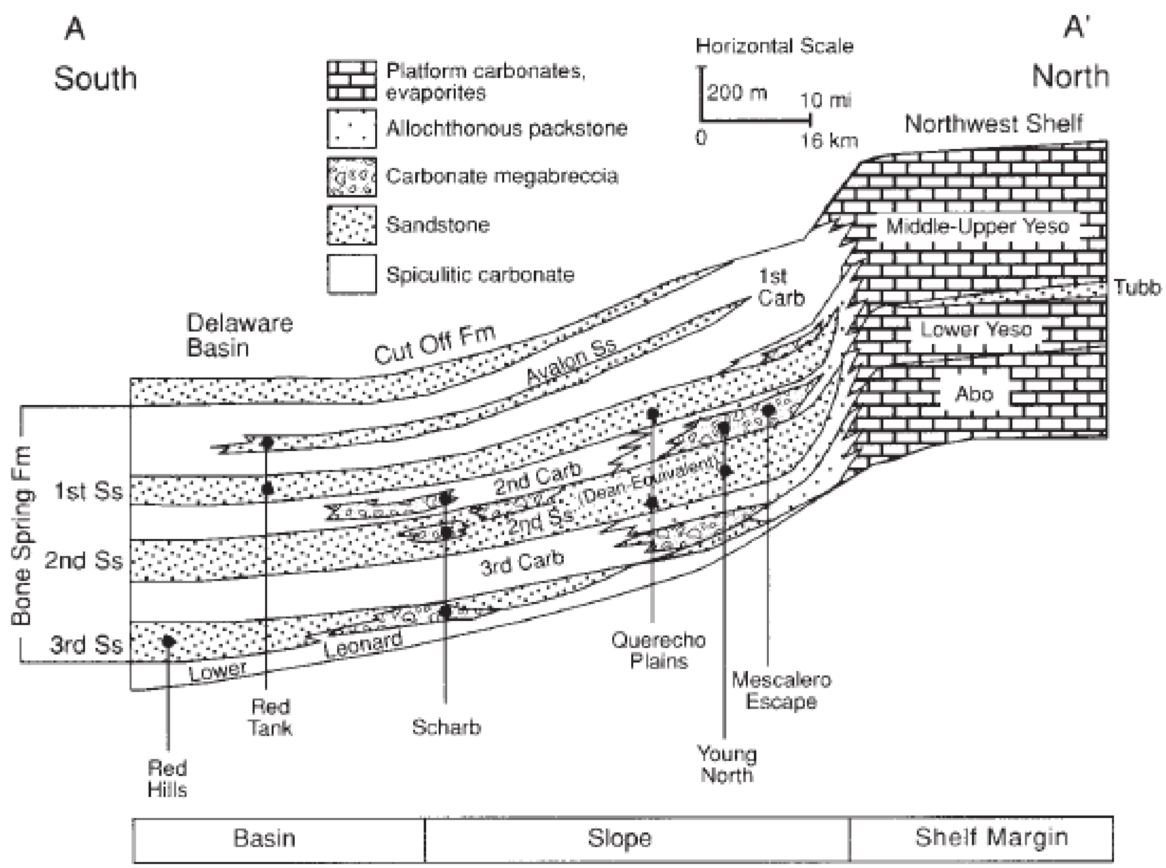


Figure 2. Stratigraphic cross section AA' of the Bone Springs formation. (Montgomery, 1997)

The first and second sandstone have very good reservoir quality and larger reserves. Reservoirs occur within the porous and permeable fine-grained quartz sandstones. Reservoir traps are mainly stratigraphic or a combination of structural and stratigraphic with lateral pinch-outs of reservoir sandstones and low-relief closures comprising the major traps. Montgomery (1997). Porosity is mostly secondary. Vugular, moldic, intercrystalline, and intergranular pores are dominant (Broadhead et al, 2004). Sandstones have high clay bound water resulting in high irreducible water saturation; water saturation ranges from 38 to 71% and averages 55%. Yet porosity values exceed 20% and typical sand porosity ranges from 8 to 20%.

The Bone Spring formation was deposited as the slope and basinal equivalent to thick carbonate sequences that rimmed the northern Delaware basin (Saller et al., 1989). Relative sea level changes are thought to have caused reciprocal sedimentation. Carbonate deposition on slopes occurred during transgression and highstand while clastics were deposited during lowstand. The first and second sandstone sediments were delivered mainly to the northern Delaware basin but extended into the basin by means of local submarine fan systems (canyons and channels, as well as slump and debris flows). The first Bone Spring sand is thin on the northern slope but shows maximum thickness at the northern shelf along the central basin platform. (Montgomery, 1997)

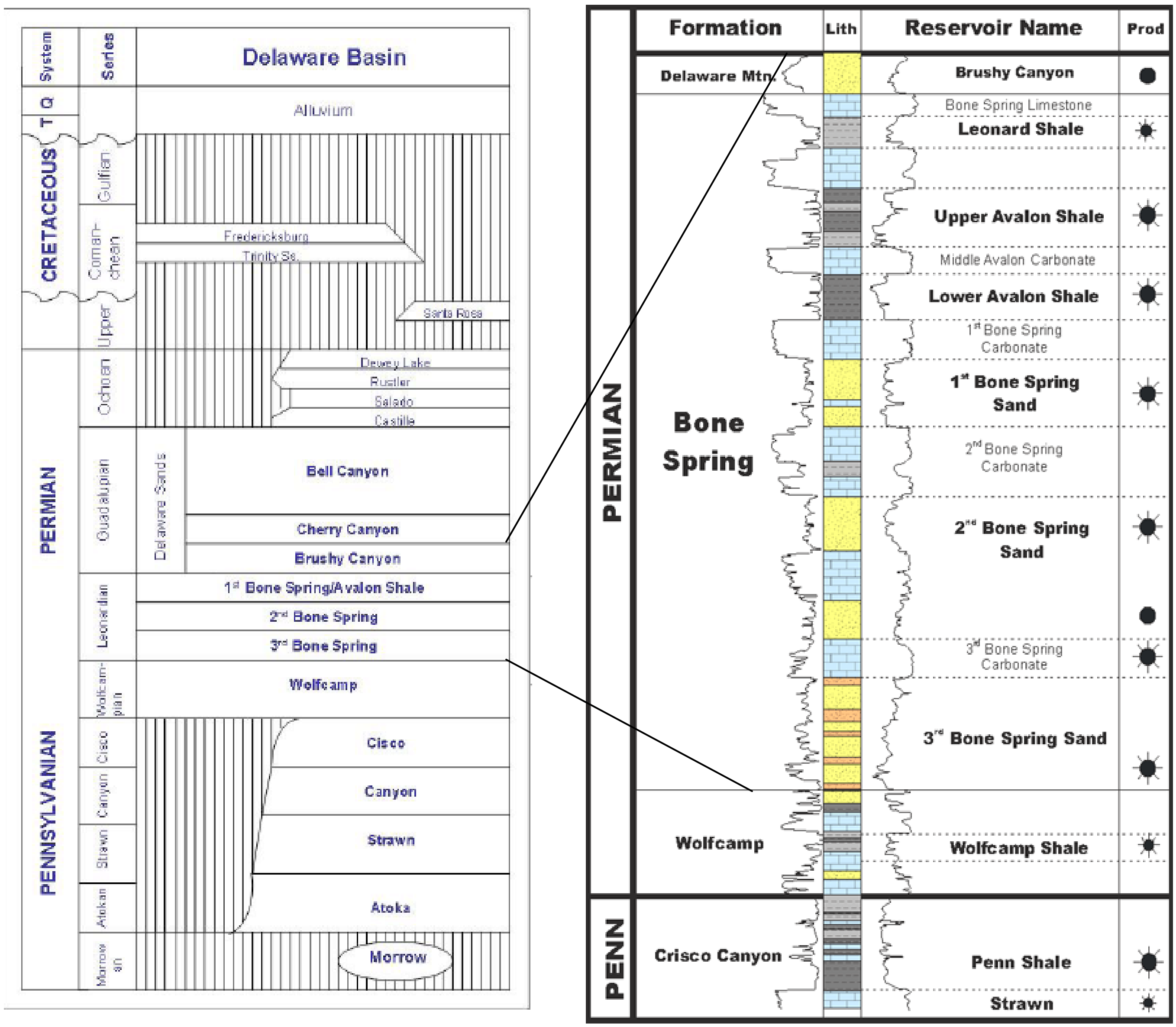


Figure 3. Stratigraphic column of the Bone Springs in the Delaware Basin. (Source: Core Laboratories)

Historical Development

The Bone Spring formation has produced approximately 117 MMBO, 318 Bscf gas, and 110 MMBW from 182 known active pools. Earliest development (Lea pool, 1961 and Scharb pool, 1962) began in the carbonate zones along the shelf margin. The carbonates are prolific oil producers and in fact, the majority of top ten pools in Table 1 have produced significant oil from the carbonate zones. The top ten list accounts for 68% of the total Bone Spring formation.

poolName	Cum_Oil* MMBO	producing horizons		percent of total	Cumulative %
SCHARB;BONE SPRING	14.4	shelf carbonate	2nd sand	12%	12%
YOUNG NORTH;BONE SPRING	13.7	shelf carbonate	2nd sand	12%	24%
RED HILLS;BONE SPRING	12.9	basin 3rd sand		11%	35%
SHUGART NORTH;BONE SPRING	12.3	shelf carbonate	2nd sand	10%	45%
MESCALERO ESCARPE;BONE SPRING	11.0	shelf carbonate		9%	55%
LEA;BONE SPRING	4.1	shelf carbonate		4%	58%
TAMANO;BONE SPRING	3.6	shelf carbonate	2nd sand	3%	61%
QUERECHO PLAINS;BONE SPRING UPPER	2.9	1st sand	2nd sand	2%	64%
E-K;BONE SPRING	2.7			2%	66%
AIRSTRIP;BONE SPRING	2.6	shelf carbonate		2%	68%

Table 1. Top ten oil cumulative oil producing pools in the Bon Spring
[Source: Dwights + digitized]

Carbonate zones would flow oil natural or with a little acid, and thus were easy to recognize and produce and thus was responsible for the growth in production (and wells) in the 1980s (see Figure 4). As stimulation technology advanced the sandstone intervals became the target; particularly the 2^{nd} sand on the shelf margin where wells could be commingled with existing carbonate producers.

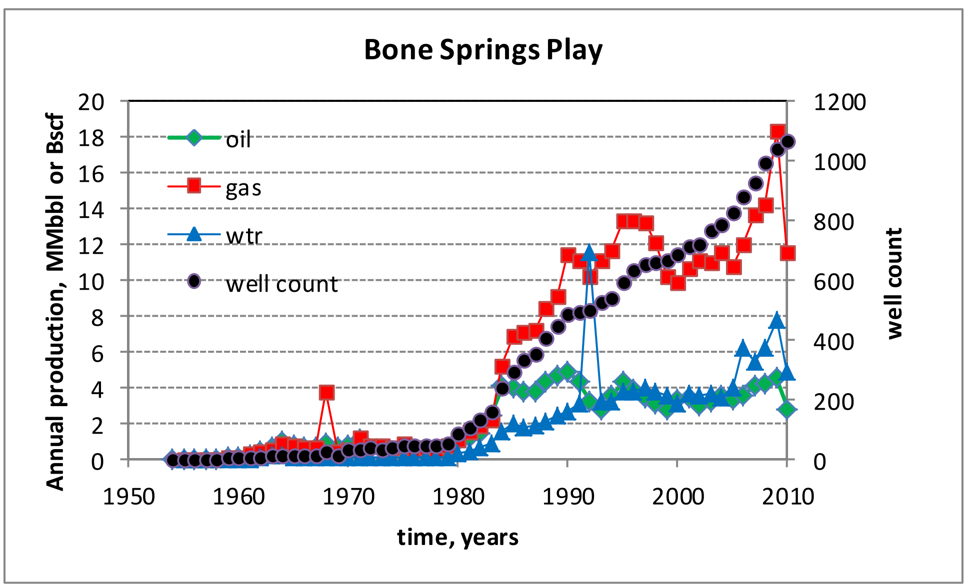


Figure 4. Annual production and cumulative well count for the Bone Spring play.
[source: digitized data + dwights]

Activity has continued to migrate basinward where the Bone Spring formation is most productive from the clastics intervals. Red Hills was established in 1993 and produces from the third Bone Spring sandstone interval. At the target depth of 12,500 ft. on the northeastern

Delaware basin, the interval is overpressured and reservoirs are intensely fractured. Typical reservoir porosities average 14% and permeability ranges from 0.5 to 2.0mD. Table 2 identifies the pools with the highest daily production rate for 2010. The majority of production is from the sandstone intervals.

poolName	2010 oil prod BOPD	horizontal wells
RED HILLS;BONE SPRING	2168	19
NASH DRAW;DELAWARE/BS (AVALON SAND)	2158	10
SAND TANK; BONE SPRING	1326	23
LUSK;BONE SPRING, NORTH	1094	10
CEDAR CANYON;BONE SPRING	914	16
SHUGART;BONE SPRING, NORTH	764	
TURKEY TRACK;BONE SPRING	606	8
HACKEBERRY; BONE SPRING, NORTH	597	4
PIERCE CROSSING; BONE SPRING, EAST	544	21
MESCALERO ESCARPE;BONE SPRING	539	1

Table 2. Bone Spring pools with highest 2010 production rate. Pools highlighted in blue are not in the top ten cumulative production list in Table 1. [Source: digitized+Dwights]

Highlighted in Table 2 and figure 6 are six pools within the top ten 2010 producing rate but not in the top ten cumulative production list. That is, these pools are recent discoveries and thus do not have a long history of production.

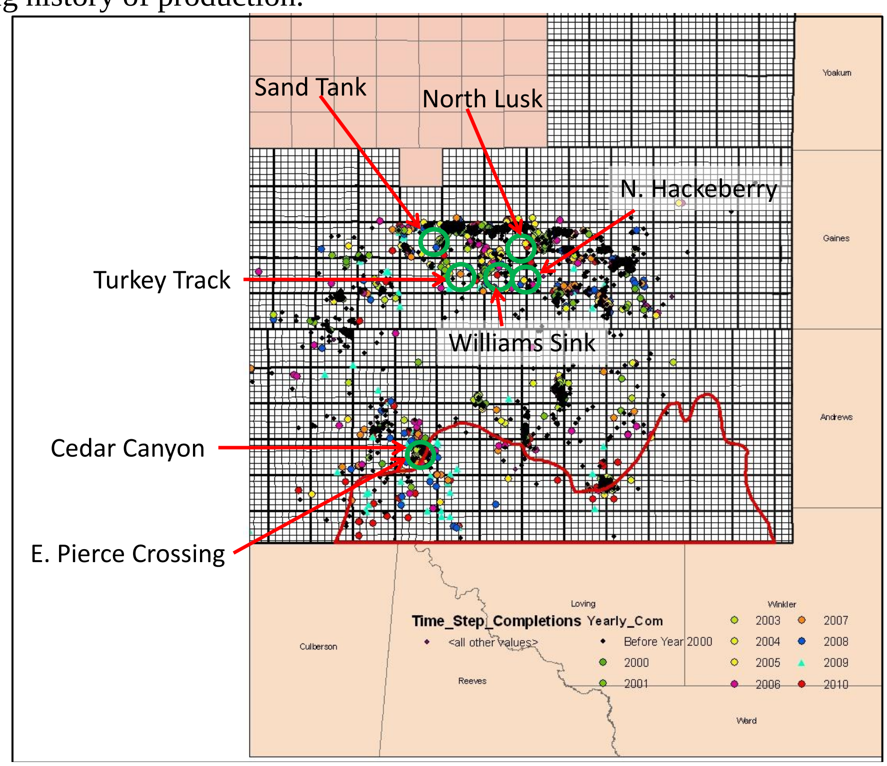


Figure 5. Bone Spring completions by year with five top 2010 producing fields labeled. (Data Source: Dwights)

Recent focus has been on the Avalon sandstone located 900ft to 1000ft above the first Bone Spring sandstone. The rocks are fine to very fine-grained submarine-fan deposits. The Avalon consists of a series of individual sandstones separated by shaly and carbonaceous siltstones. Pay thickness range from 33 ft to 59 ft, porosities range between 8% to 15% and permeability from 0.5 to 7.2mD. Average tested water saturation is 40-62% and oil saturation is below 30%. Published data (Table 3) shows the Avalon comparable to other active shale plays in the U.S.

Play Characteristic	Avalon shale	Wolfberry	Eagle Ford Shale	Bakkan
Depth, ft	**6,200 - 9,400**	8,000 - 11,000	5,000 - 8,000	7,000 - 11,000
Thickness, ft	**200 -500 (1000' gross)**	3,000+	200 - 300	20 -100
Lithology	**organic rich siltstone. Lms**	shale, ss, carbonate	shale, carbonate	sandstone, shale
TOC	**4 - 11%**	?	4.4 - 4.7%	2 - 18%
Porosity, %	**8-15**	4-11	9-11	3 - 12
Total perm, md	**~0.0001**	~0.0001	<0.0001 - 0.003	0.02 - 0.1
oil gravity, API	**50**	40	35 - 61	42
NGL, gpm	**4.8**	14	3.8	N/A
CO2 content	**10 -12%**	~	4%	N/A
well spacing, acres	**160**	160	120 -140	1280
Total MBOE/well	**455**	164	761	

Table 3. Comparison of the Avalon Shale characteristics with other recently active shale plays

The Avalon Shale play has been restricted to southernmost Eddy and Lea counties where the clean sand thickness is the greatest. Figure 6 shows the outline of the 200 ft clean sand thickness line. Wells within this area are a combination of Avalon and Bone Spring sand completions.

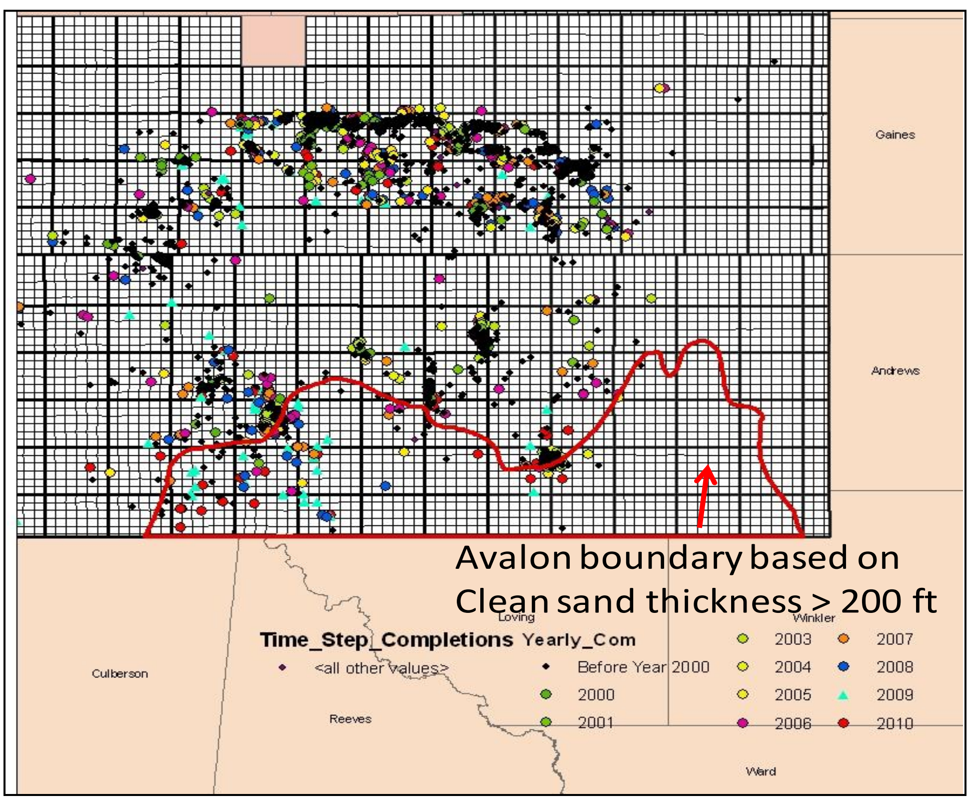


Figure 6. Bone Spring completions by year. The red outline delineates the 200 ft clean sand thickness of the Avalon.

The recent success of the Bone Spring sands and Avalon Shale is attributed to the combination of improved stimulation techniques with horizontal wells. In Table 2, the majority of active, high producing pools are completed with horizontal wells, and in 2010 nearly two-thirds of all Bone Spring completions were horizontal (Figure 7).

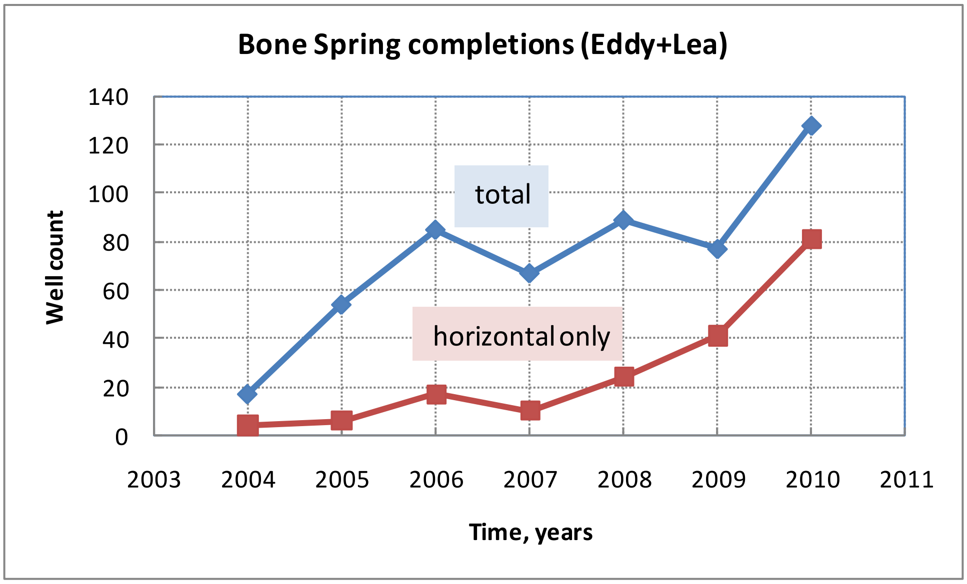


Figure 7. Annual Bone Spring completions for Eddy and Lea counties and annual horizontal well completions. (Data Source: GOTECH+Dwights)

Locations of the highest activity for horizontal wells coincide with the Red Hills (3^{rd} sand) development (southeast circle in Figure 8), the Avalon Shale play (southwest circle) and the Second sand play of Sand Tank, Lusk and others along the shelf margin (northern most circle). The success of the horizontal wells is evident by the number of horizontal wells in the best 2010 producing pools listed in Table 2, and in the production curve shown in Figure 9. Figure 9 shows the difference in production with and without horizontal wells. In 2010, an additional 1.5 MMBO was produced from the horizontal wells.

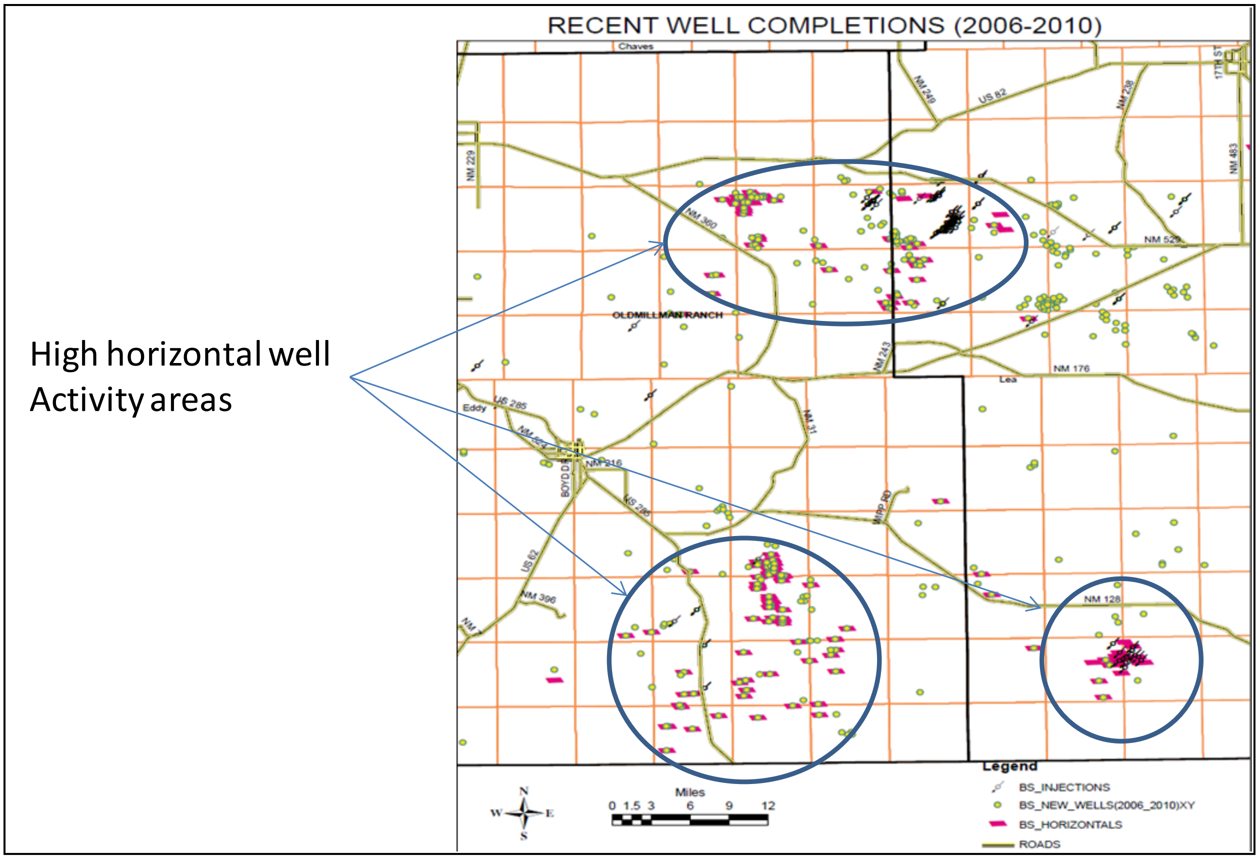


Figure 8. Highest active Bone Spring horizontal well areas (Data Source:Drilling Info)

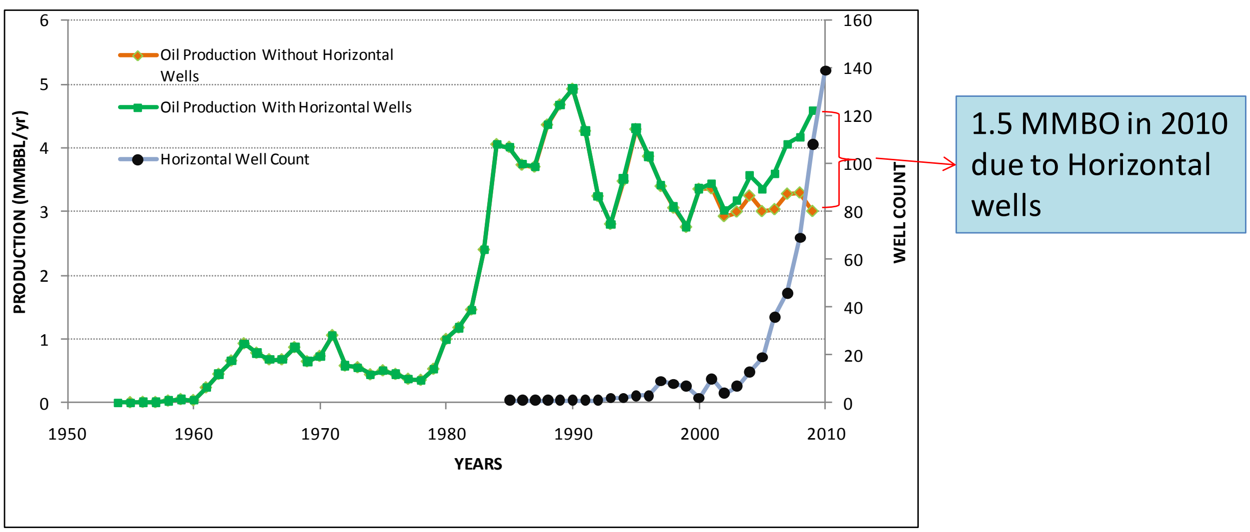


Figure 9. Annual Oil Production curve for Bone Spring with and without horizontal wells, and horizontal well count. (Data source: digitized+Dwights)

A comparison of vertical and horizontal cumulative oil production revealed an increase in production from horizontal wells for recent five years of development (Figure 10). The trend should decrease since less time is available. The horizontal wells show this pattern; the vertical wells also exhibit the expected pattern except for 2010 where an anomalous increase occurs. The horizontal to vertical ratio is 2.0 for the entire period.

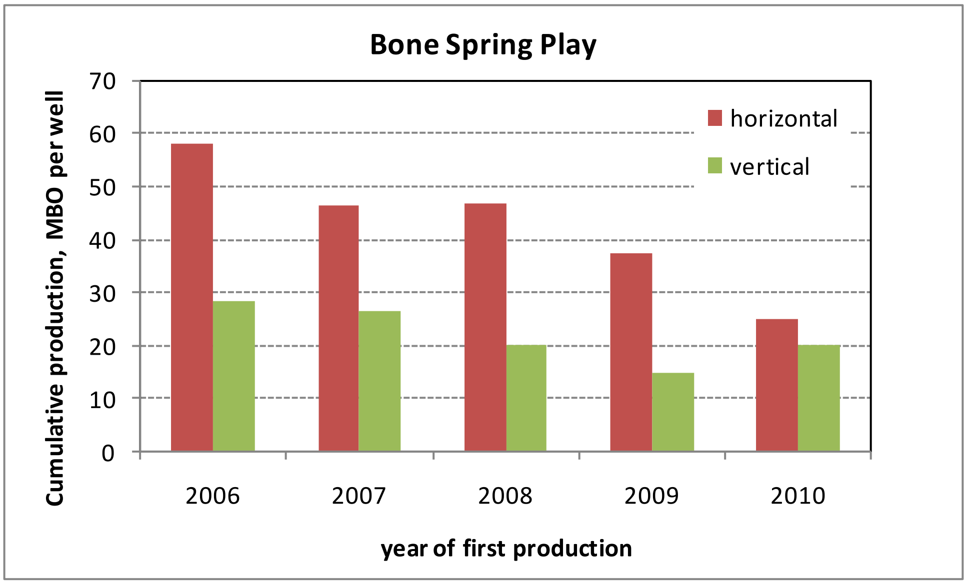


Figure 10. Comparison of horizontal and vertical cumulative oil production based on year of beginning of production. (Data source: GOTECH)

Four pools (figure 11) have a history of waterflooding, with mixed results. Tamano and North Young were pressure maintenance projects in the carbonate interval. The high permeability and natural fractures resulted in rapid water breakthrough. Figure 12 is the production curve for Tamano pool. Notice the severe increase in WOR.

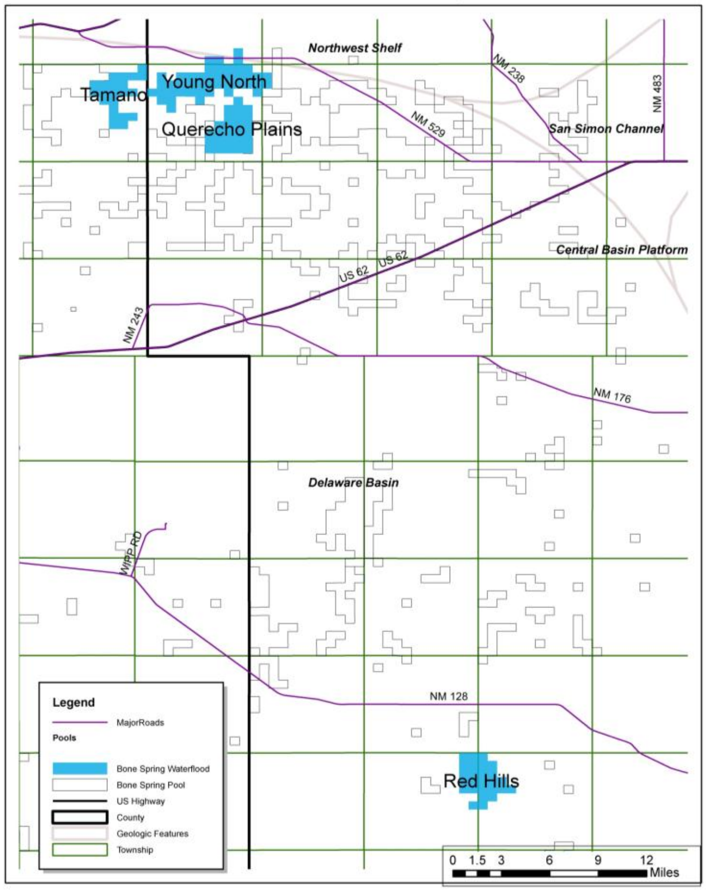


Figure 11. Location of four Bone Spring pools that have been waterflooded

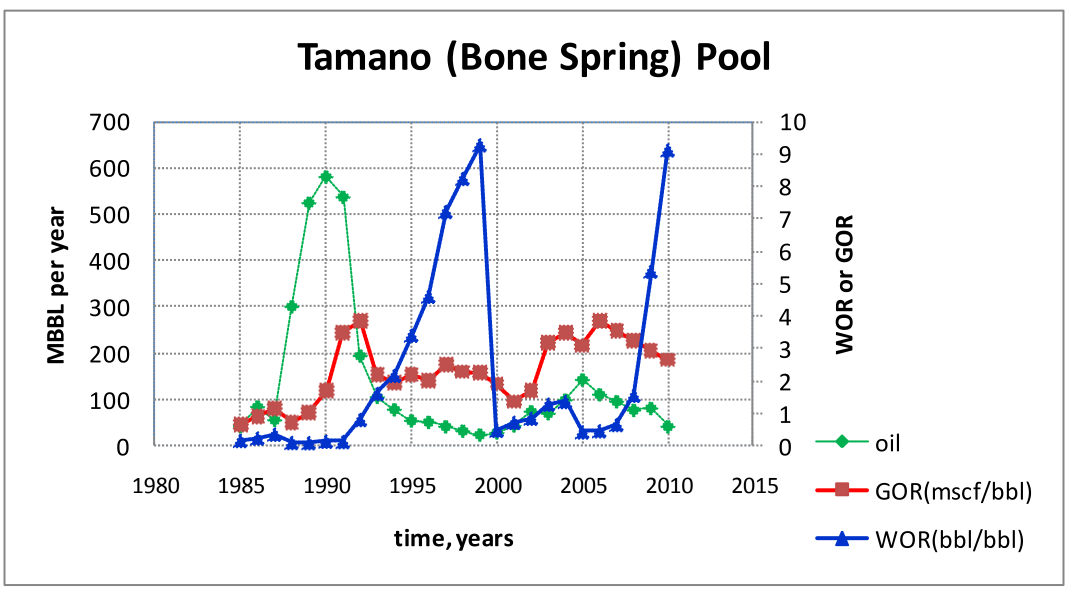


Figure 12. Performance curves for Tamano Pool. (Data Source: Dwights)

In the Querecho Plains and Red Hills pools the sands were the target of the water injection. Figure 13 shows the production response due to waterflooding for the Querecho Plains pool. Secondary to primary production ratio is 0.6.

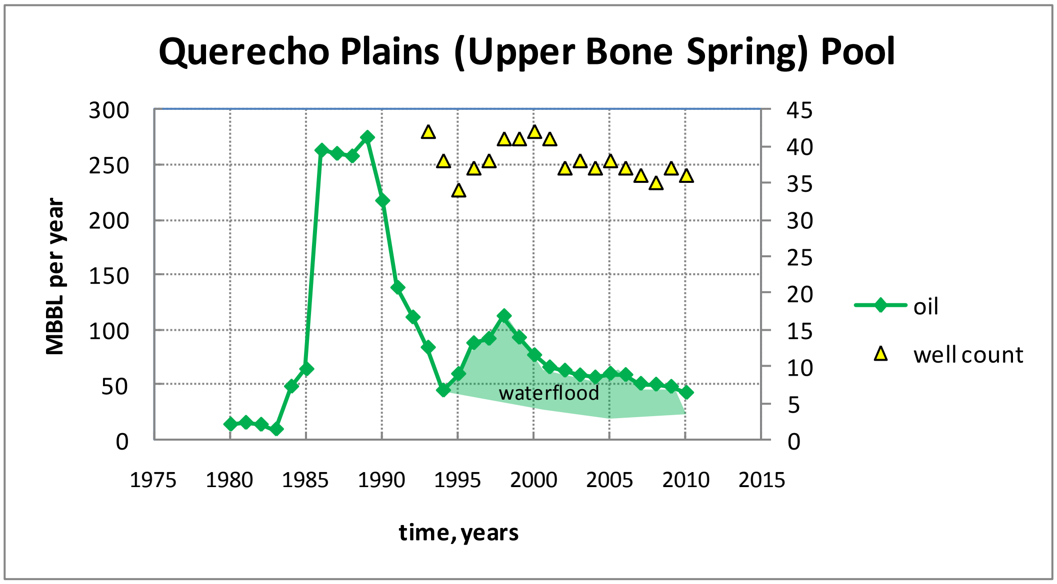


Figure 13. Performance curve for the Querecho Plains Pool (Data source: GOTECH & Dwights)

In the Red Hills the 3rd Bone Spring sand is the target. Water injection commenced in 2003, but didn't inject significant volumes of water until two years later. Oil production response is not evident in Figure 14; therefore it is likely this project is for pressure maintenance purposes. Unique to this waterflood is the addition of horizontal injectors in the Bone Spring sand. Four wells have either been drilled as a horizontal injector or converted from an oil producer. At this time, it is not possible to discern if production has increased due to the horizontal injection.

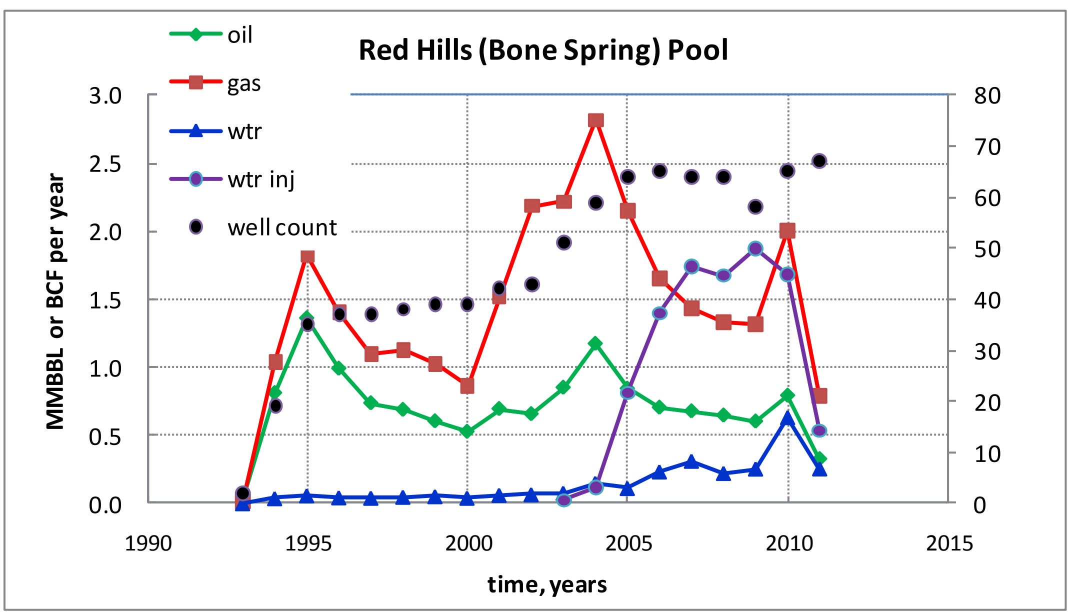


Figure 14. Performance curve for the Red Hills Pool (Data source: GOTECH)

POTENTIAL DEVELOPMENT

Recent activity is on an increasing trend (Fig 7); with horizontal well completions playing a dominate role. Based on the success of horizontal wells (Figs. 9 and 10), this trend is predicted to continue.

The area of greater than 200 feet of Avalon Shale thickness was divided into three regions; high, moderate and low potential. Potential is based on using well activity as indicator. The high potential region consists of 186,000 acres or 1,162 locations assuming 160 acres per horizontal well. Within this region 35 horizontal wells and 90 vertical wells already exist, thus 1,000 locations remain. Similar calculations for the other regions result in the moderate potential region with 126,000 acres (750 locations less previous development) and for the low potential region 275,000 acres (1,700 locations less previous development). Assuming a risk factor of 90, 50 and 10% for high, moderate, and low potential; the resulting locations are 900, 375, and 170; respectively, resulting in 1,445 horizontal well locations for the Avalon Shale or Bone Springs sand play.

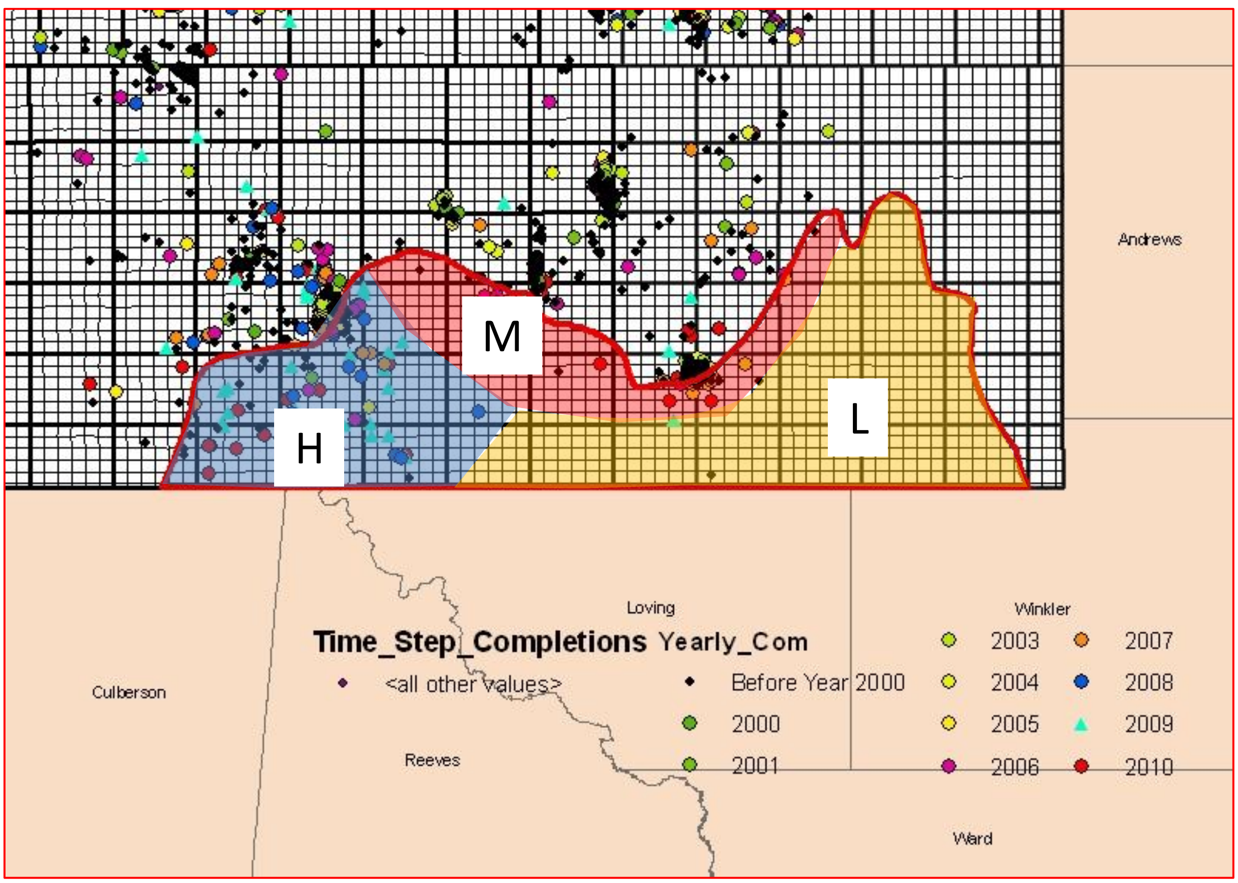


Figure 14. High, moderate, and low potential regions of the Avalon/Bone Spring play in southern Lea and Eddy counties. The red outline delineates the 200 ft clean sand thickness of the Avalon. (Data source: Dwights)

A second area of high activity is in the shelf margin located in the northern portion of the Delaware Basin. This area has been highlighted in Figure 15. The total acreage within the yellow bounded area is 506,000 acres. To date, 1170 wells have been drilled and completed in the Bone Spring in this area; of which approximately 70 are horizontal wells. Remaining undeveloped acreage of ~400,000 acres is predicted to support an additional 1200 horizontal wells; assuming 160-acre spacing for a horizontal well and risking the probability of success by half.

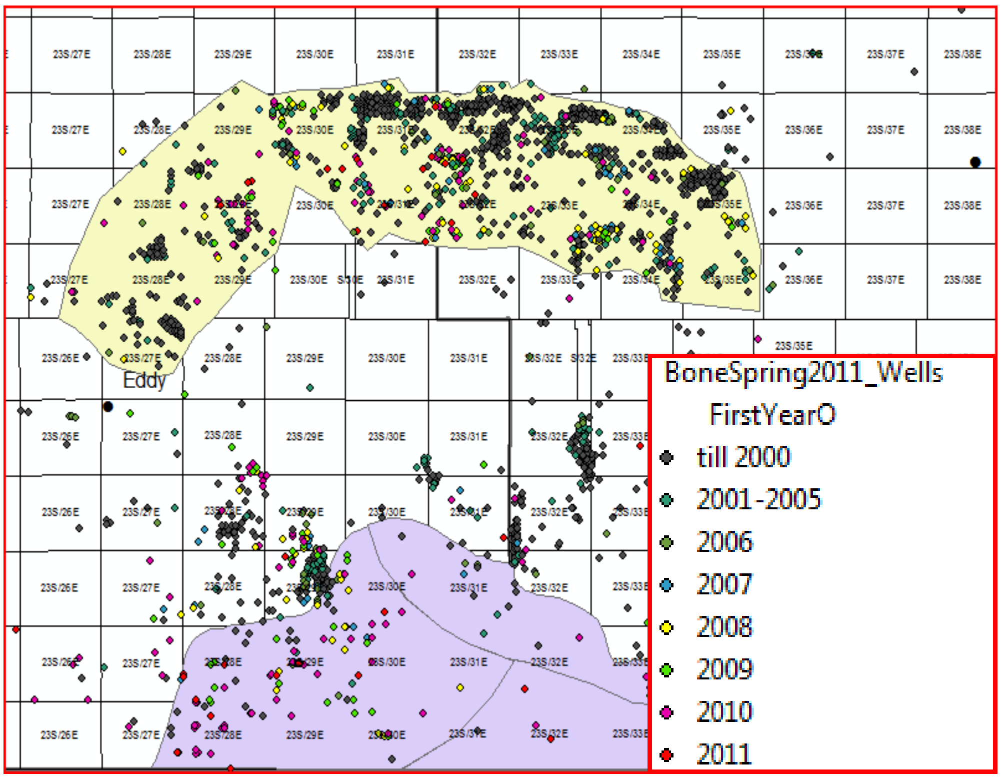


Figure 15. Bone Springs development with the shelf activity highlighted in yellow. (Data Source: Drilling Info).

Long term potential exists for waterflooding the Bone Spring sands. The success of Querecho Plains (Fig . 13) and eventual results from Red Hills supports investigating additional secondary recovery projects. Further long term are the potential for EOR-CO_2 injection projects; something not attempted yet in the Bone Spring.

Delaware Mountain Group Basinal Sandstone Play

The potential for future development is ***high***. Opportunities to further exploit the Delaware play exists. These opportunities include additional locations for infill and/or stepout drilling, the addition of horizontal wells and/or waterflooding. Recent activity in all three has been successful. Completions in the Delaware sand play have averaged slightly less than 100 per year since 2004 (Figure 10), the majority in Eddy county. This trend is expected to continue.

BRIEF SUMMARY OF GEOLOGY

In New Mexico, the Delaware Mountain Group is comprised of sands that are usually very fine to fine grained arkosic to subarkosic [Montgomery, et al, 1999] and are complexly interbedded with siltstone and low permeability sandstones not of reservoir quality [Broadhead, et al, 2004]. The sands were deposited by some type of gravity-flow mechanism(s) with submarine fans and channels from the northwest shelf or central basin platform as the major sediment conduits (Fig 1.).

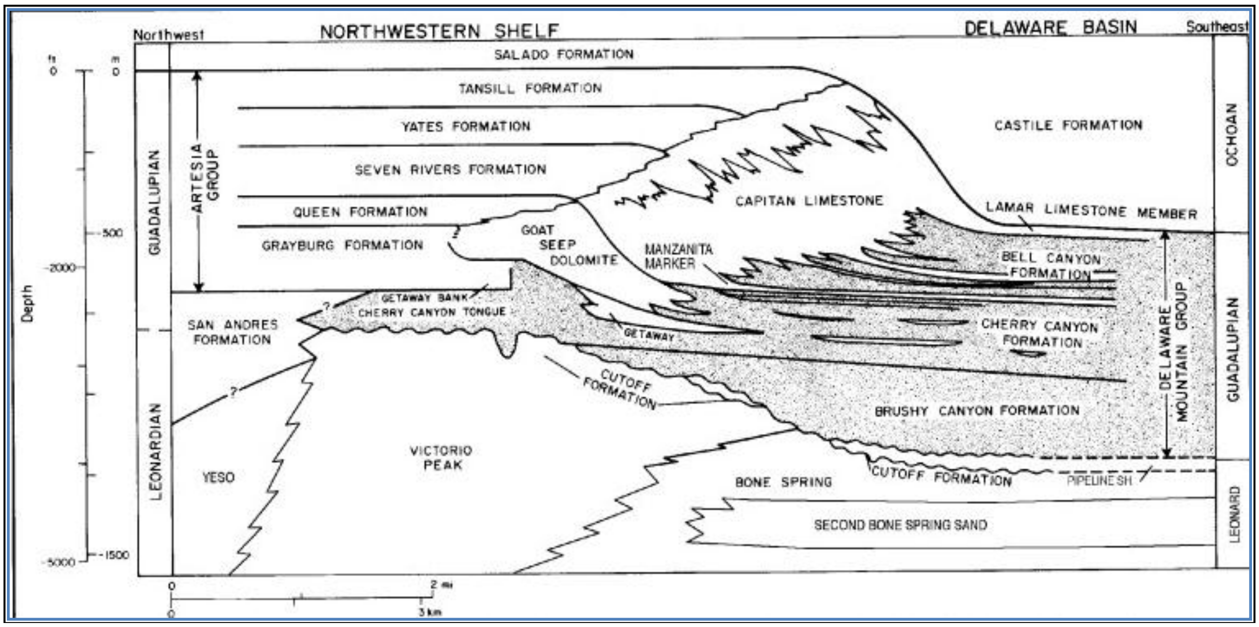


Figure 1. Stratigraphic Relationships between the Northwest shelf and Delaware basin [Montgomery, et al, 1999]

The productive intervals are separated into three sections. As shown in Fig. 2, from top to bottom are the Bell Canyon, Cherry Canyon and Brushy Canyon intervals. The gross thickness is ~4,500 ft with 30 to 90 feet of interbedded net pay. Porosity ranges from 12-25% and permeability from 1 to 5 md. Primary recovery is low, typically <10%; therefore waterflooding and EOR-CO_2 have been implemented to improve recovery.

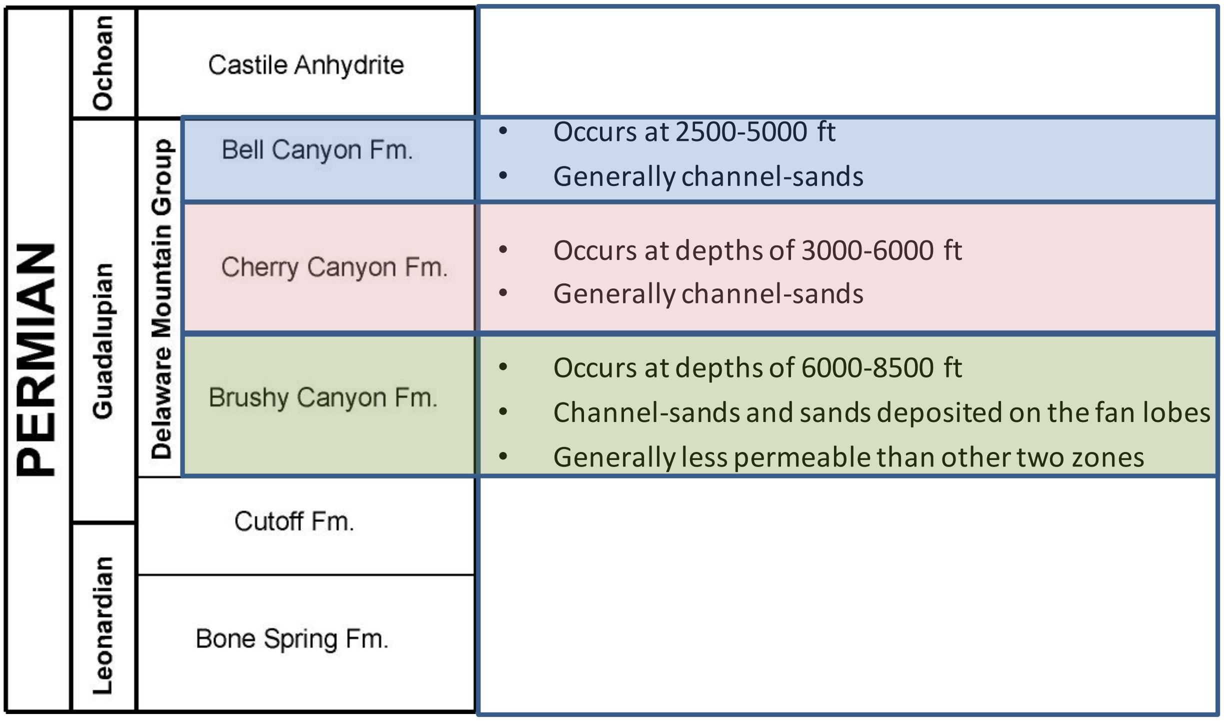


Figure 2. Stratigraphic chart of the Delaware mountain group.

Traps in the Delaware Mountain Group are generally interpreted as being predominantly stratigraphic, related to lateral and updip pinchouts of porous sandstone facies. Production is generally from multiple layers due to complex interbedding with non-reservoir facies. This also results in the interpretation that there in not a single, but multiple oil-water contacts [Broadhead, et al, 2004].

For more information on the Delaware, excellent published geologic studies [Montgomery, et al, 1999, 2000] exist and are recommended.

HISTORICAL DEVELOPMENT

Development of the Delaware sands occurred in stages beginning with the shallowest Bell Canyon Formation in the 1950s and 1960s. During the late 1970s and early 1980s, the Cherry Canyon was the exploration target, and then the final activity was the development of the Brushy Canyon Formation in the 1990s. To date, approximately 250 pools are reported as producing from the Delaware in Southeast, New Mexico. Through 2010 cumulative production has been 234 MMBO, 523 Bscf, and 742 MMBW. First reported production was in 1948 in the Black River Delaware Field south of Carlsbad in Eddy County. Oil production increased in the early 1990s due to increased development (see Fig 3) and has been steady ever since. Water production has significantly increased since 1990 to where the 2010 WOR is slightly greater than 6 to 1. Waterflooding rapidly became popular in the mid-1990s and as a result water injection significantly increased as well.

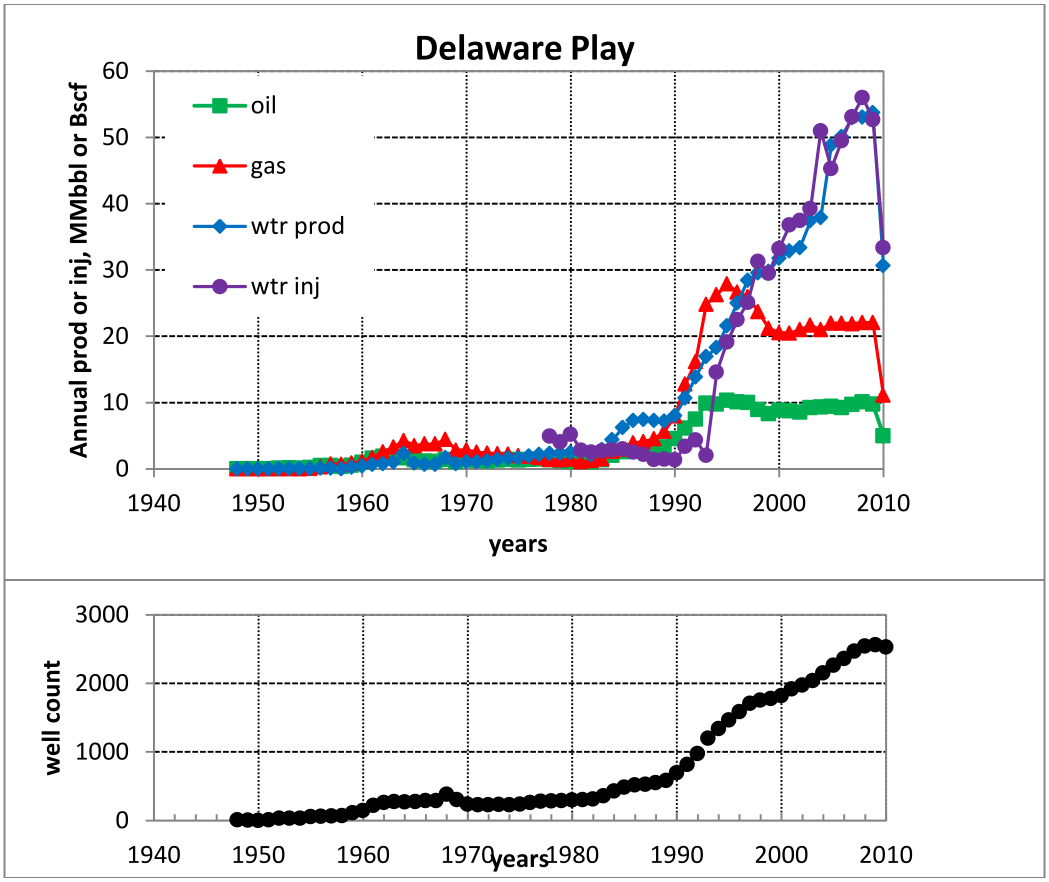


Figure 3. Annual production and injection and well count for the Delaware Sand Play. [Source: digitized data + IHS Energy]

Location of the major Delaware oil pools is shown in Figure 4. From this group, the top ten pools by cumulative oil production are listed in table 1. They account for 42% of the cumulative oil produced from the Delaware pools.

poolName	Cum_Oil* MMBO
INGLE WELLS;DELAWARE	15.3
PADUCA;DELAWARE	13.2
LOVING;BRUSHY CANYON, EAST	11.6
RED TANK;DELAWARE, WEST	10.4
SAND DUNES;DELAWARE, WEST	9.1
BRUSHY DRAW;DELAWARE	8.7
LIVINGSTON RIDGE;DELAWARE	7.9
PARKWAY;DELAWARE	7.4
AVALON;DELAWARE	7.1
NASH DRAW;DELAWARE/BS (AVALON SAND)	6.9

Table 1. Top ten producing oil pools in the Delaware play. *Cumulative production through 2010.

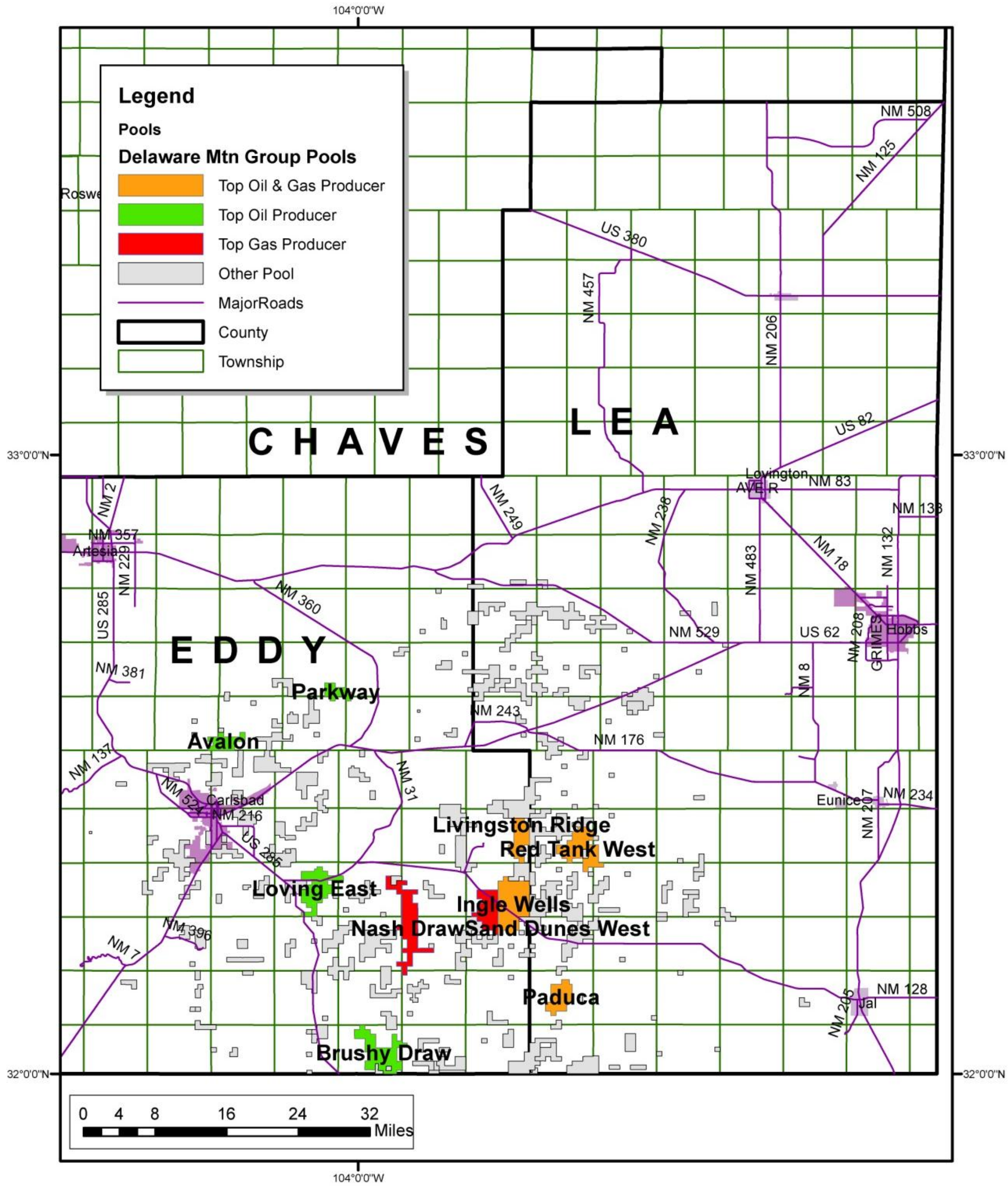


Figure 4. Pool map for the Delaware Mountain Sandstone play

Top producing pools for 2010 are shown in Table 2 and account for ~13,000 bopd or slightly less than half of the 2010 daily production. Names highlighted in blue have recently been developed and thus are not on the top cumulative production list (Table 1). The locations of these pools are also shown in Figure 5.

poolName	2010 oil prod BOPD	horizontal wells	water flood
QUAHADA RIDGE;DELAWARE, SOUTHEAST	2656	17	
NASH DRAW;DELAWARE/BS (AVALON SAND)	2158	11	
INGLE WELLS;DELAWARE	1646	2	
SAND DUNES;DELAWARE, WEST	1054		
LOVING;BRUSHY CANYON, EAST	1014	1	
LOS MEDANOS;DELAWARE	905	10	
RED TANK;DELAWARE, WEST	816		
LOST TANK;DELAWARE	799	1	
LIVINGSTON RIDGE;DELAWARE	773		Y
PARKWAY;DELAWARE	737		Y
SHUGART;DELAWARE, EAST	694		Y

Table 2. Top oil producing pools in the Delaware play for 2010.

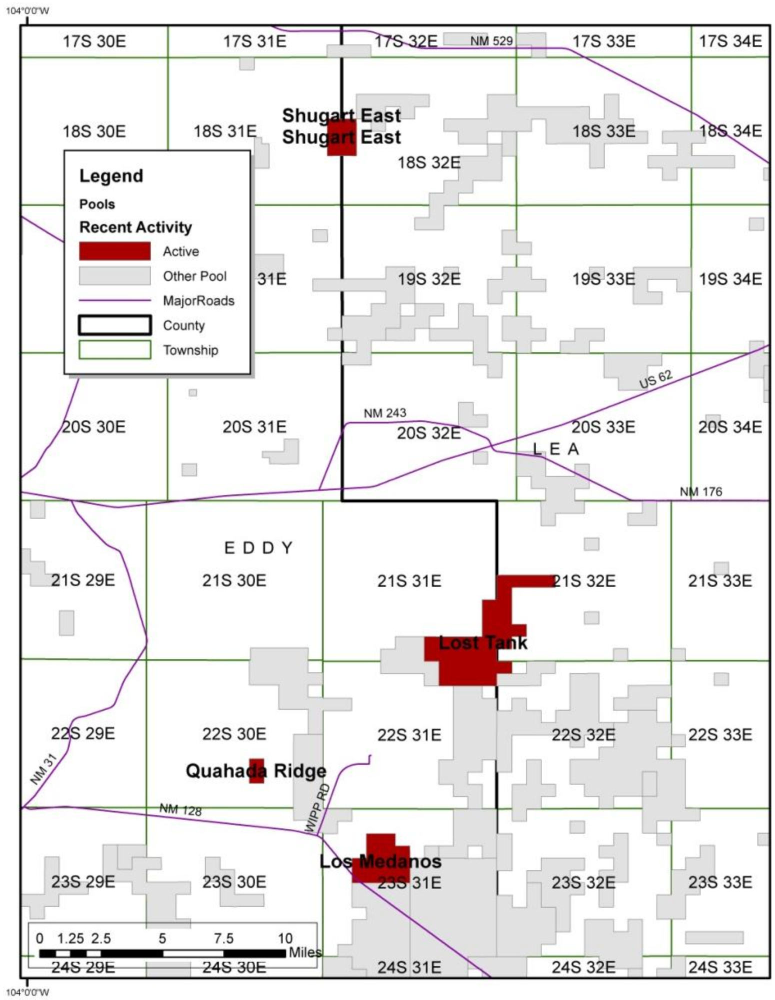


Figure 5. Location of top oil producing pools in 2010 that are not listed as a top cumulative pool in table 1.

An example of redevelopment is shown in Figure 6 for the Lost Tank (Delaware) Pool. Note prior to 2000 the well count was constant, but since 2000 well count has doubled. Cumulative production for this pool is 6.2 MMBO of which approximately half can be attributed to the re-development.

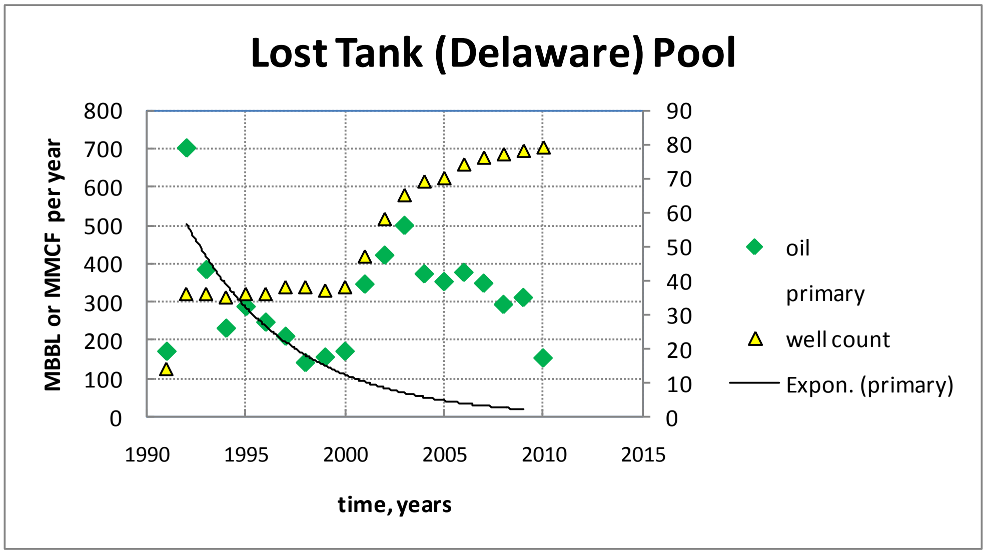


Figure 6. Annual oil production and well count for the Lost Tank (Delaware) Pool. Note: gas and water production not shown. (Source: IHS Energydata)

The typical Delaware Sand reservoir produces by solution gas drive and thus exhibits an early rapid decline. As a consequence primary recovery is only ~ 10%. Waterflooding is encouraged early to prevent development of secondary gas cap.

Proximal upper Brushy Canyon and lower Cherry Canyon reservoirs are thought to have less lateral sandstone heterogeneity than other reservoirs in the Brushy Canyon and Cherry Canyon and may be more favorable to waterflooding (Montgomery et al., 1999).

Eight pools have indicated past waterflood development. The location of these pools is shown in Figure 7. Evaluation of the production curves was accomplished to determine the success rate of waterflooding the Delaware sands.

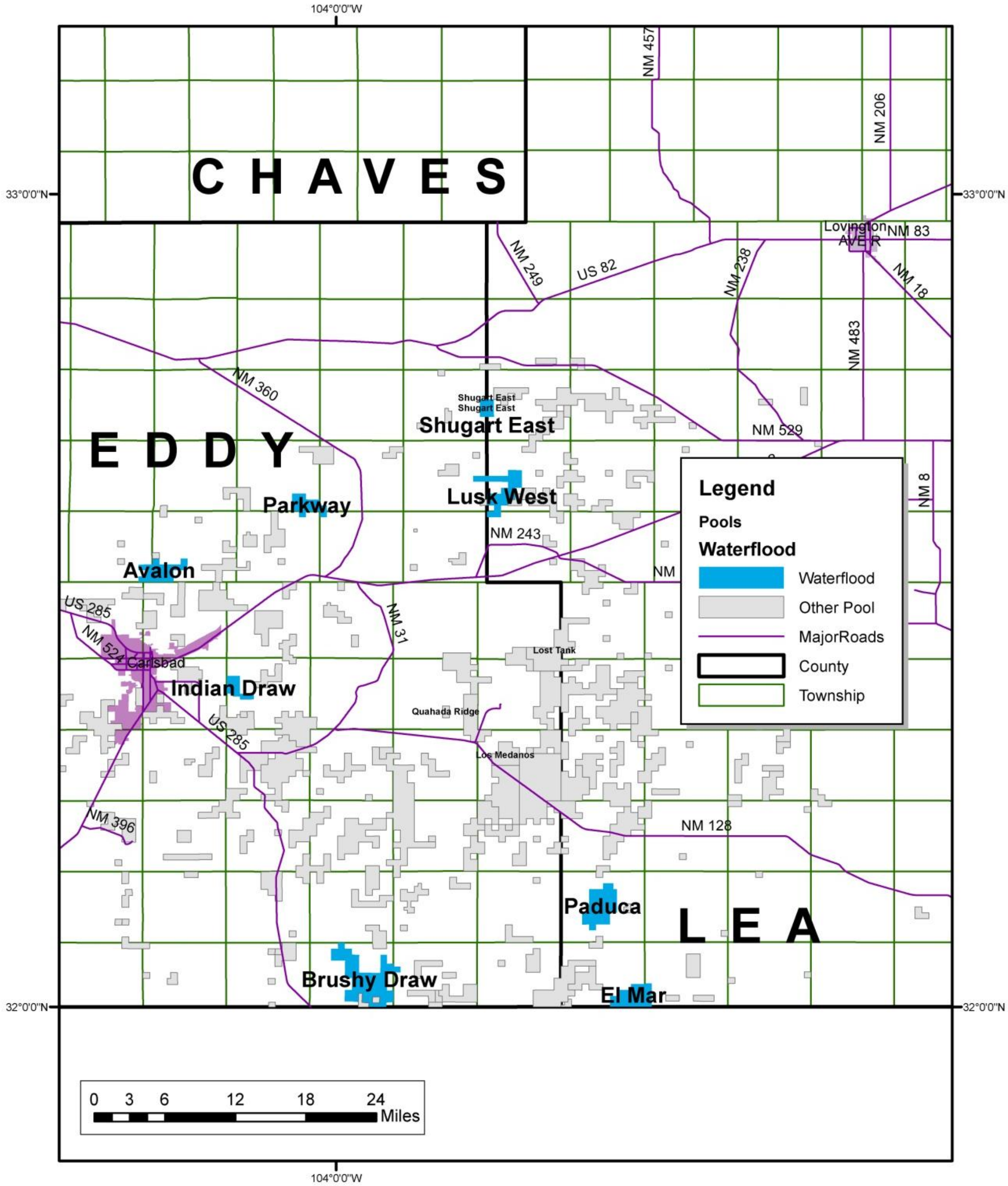


Figure 7. Location of major waterflooded pools in the Delaware.

Figure 8 is an example of a successful waterflood development project in the Parkway pool. Pilot injection commenced in 1993 and was later expanded in 1998. Secondary response (highlighted in blue) is evident. The secondary to primary oil ratio was 1.5:1.

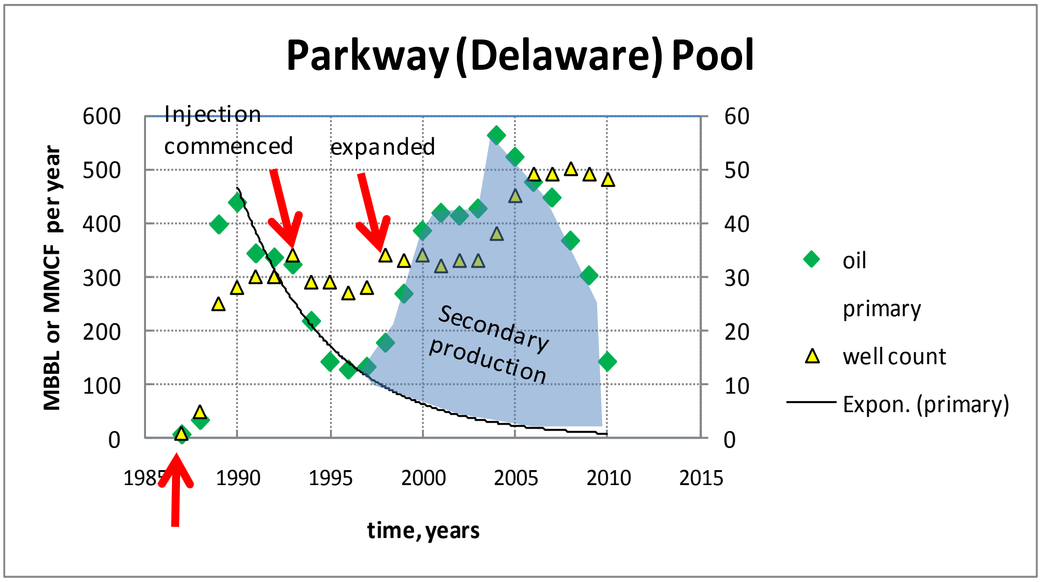


Figure 8. Production curve for the Parkway (Delaware) Pool Note: gas and water production not shown. (Source: IHS Energydata)

Table 3 summarizes the results from the evaluation of the water flooded pools. Secondary-to-primary response ranges from none to a high of 1.50; averaging 0.75. Overall these results indicate the Delaware sands are good candidates for waterflooding and thus potential exists.

Poolname	Yr of first production	Yr of first injection	S:P ratio	formation	comments
Avalon	1977	1996	0.44	Lower Cherry Canyon and Upper Brushy Canyon	good waterflood response
Brushy Draw	1959	1990	none observed	Cherry Canyon and Brushy Canyon	insufficient injection
El Mar	1959	1978*	none observed	Bell Canyon - Ramsey and Olds sands	Approved WF in 10/68, no waterflood response
Indian Draw	1973	1981	1.17	Cherry Canyon	excellent waterflood response
Los Medanos	1990	2004	N/A	Lower Brushy Canyon	limited injection, response due to add dev
Lost Tank	1991	2004	N/A	Brushy Canyon	limited injection, response due to add dev
Lusk, West	1987	1997	0.28	Brushy Canyon	fair waterflood response
Paduca	1961	1978*	0.73	Bell Canyon - Ramsey and Olds sands	Approved WF in 9/67, excellent waterflood response
Parkway	1987	1993	1.50	Brushy Canyon	excellent waterflood response
Shugart, East	1985	2001	0.42	Upper Brushy Canyon	good waterflood response

* Earliest year Dwights reports injection data

(blue)	Top ten oil producing pool for 2010
(pink)	Top ten cumulative oil producing pool

Table 3. Summary of waterflood results

Horizontal well development in the Delaware has been slightly increasing since 2004, averaging 15 per year (See Figure 9). One of the pools with a high concentration of horizontal wells is Quahada Ridge; the top producing pool in 2010 (see Table 2).

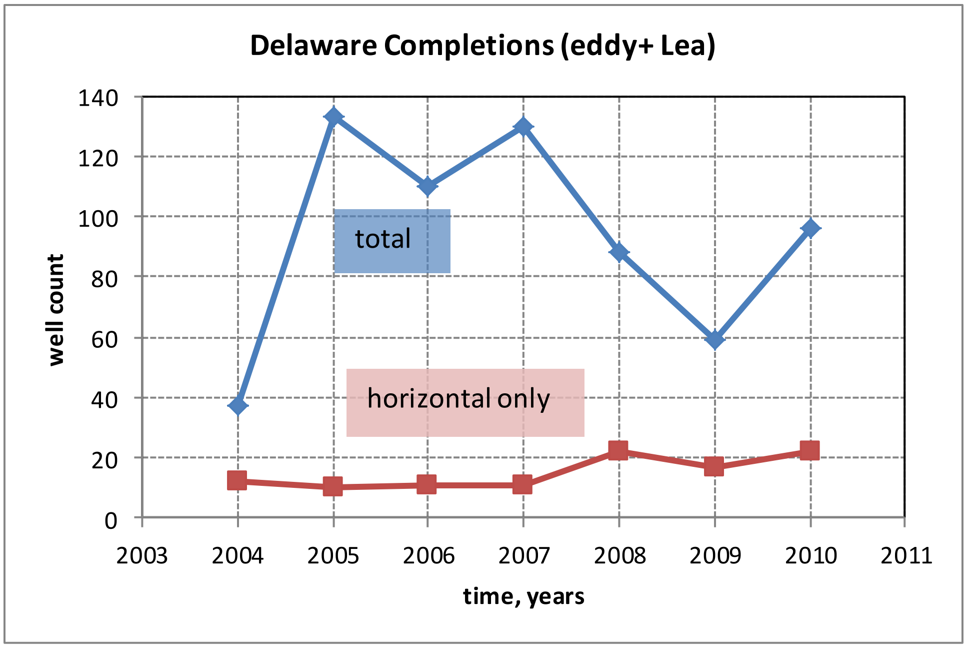


Figure 9. Annual total and horizontal only well completions for Eddy + Lea counties.

FUTURE DEVELOPMENT

Opportunities to further exploit the Delaware play exists. These opportunities include additional locations for infill and/or stepout drilling, the addition of horizontal wells and/or waterflooding. Recent activity in all three has been successful. Completions in the Delaware sand play have averaged slightly less than 100 per year since 2004 (Figure 10), the majority in Eddy county. This trend is expected to continue.

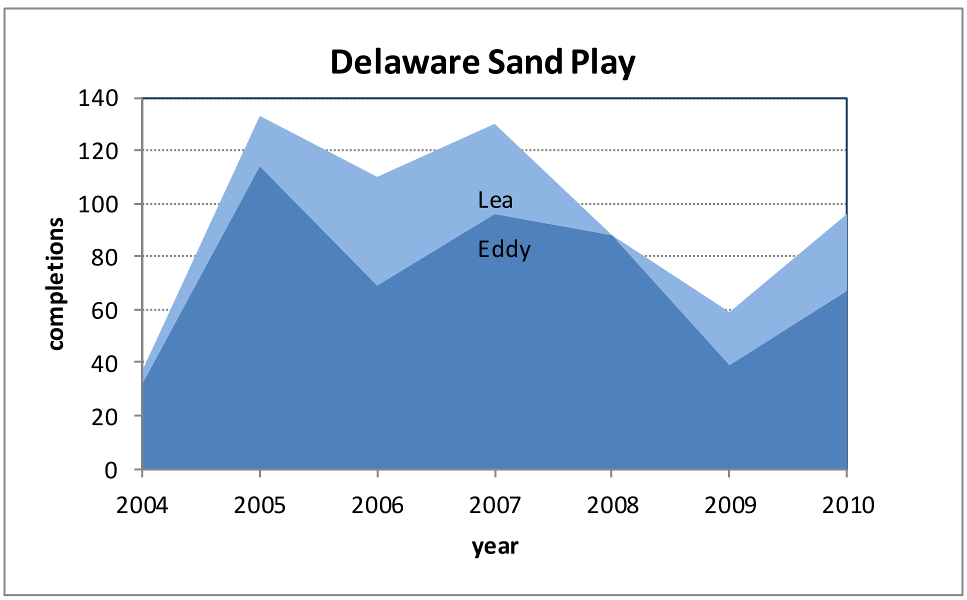


Figure 10. Completions in the Delaware Sands play from 2004 to 2010.

Horizontal wells will play a more important role in future Delaware development. The success of current horizontal well activity as shown in Table 2 supports this prediction. Some of the top producing pools for 2010 have significant number of horizontal wells.

Analysis of the largest waterflood pools indicated good response to water injection. Approximately 40 other pools are reported to be injecting water; all with less than two injectors and thus not fully developed to date. A comparison shown in Fig 11 of the waterflooded pools to all Delaware pools indicates pools with water injection are skewed to the better reservoirs. Consequently, additional waterflood potential exists; but will require more effort to be successful.

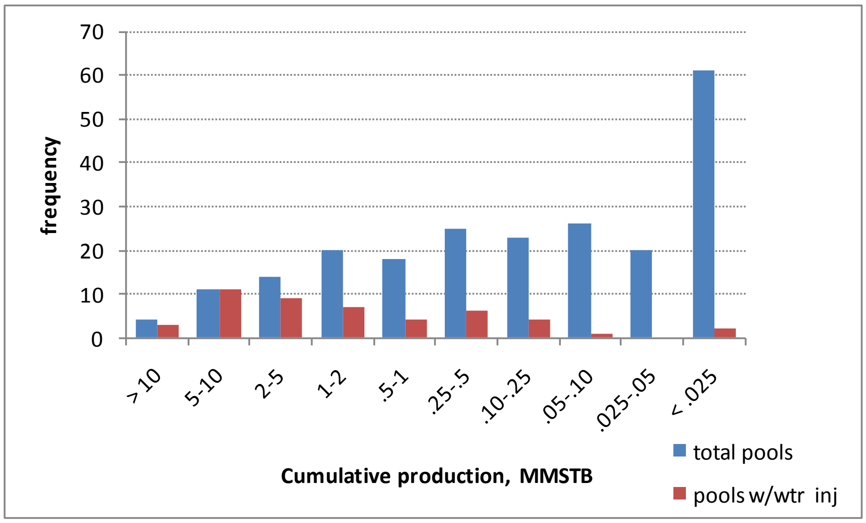


Fig 11. Histogram of cumulative production for Delaware pools with and without water injection

Furthermore, the increase in water production will require expansion of the disposal/injection system. Figure 3 clearly demonstrates the direct relationship between water production and injection.

Tertiary recovery is also a viable option for development. In other more heterogeneous, more distal Delaware reservoirs with complex internal sandstone distributions and lower permeability, gas injection may be required for optimum pressure maintenance and carbon dioxide flooding may be needed for enhanced recovery (Montgomery et al., 1999). Several CO_2 injection projects (Two Freds and Ford Geraldine) into Delaware sand reservoirs have been very successful in Texas. A study by A.R.I. (2006) identified the Paduca (Delaware) Pool as amenable to CO_2 injection.

Combining all of the development opportunities discussed, a potential map was constructed and is shown in Figure 12. The high potential area encompasses the top oil producing pools, most of the top pools producing in 2010 and several of the largest waterfloods.

Delaware Mountain Group Play

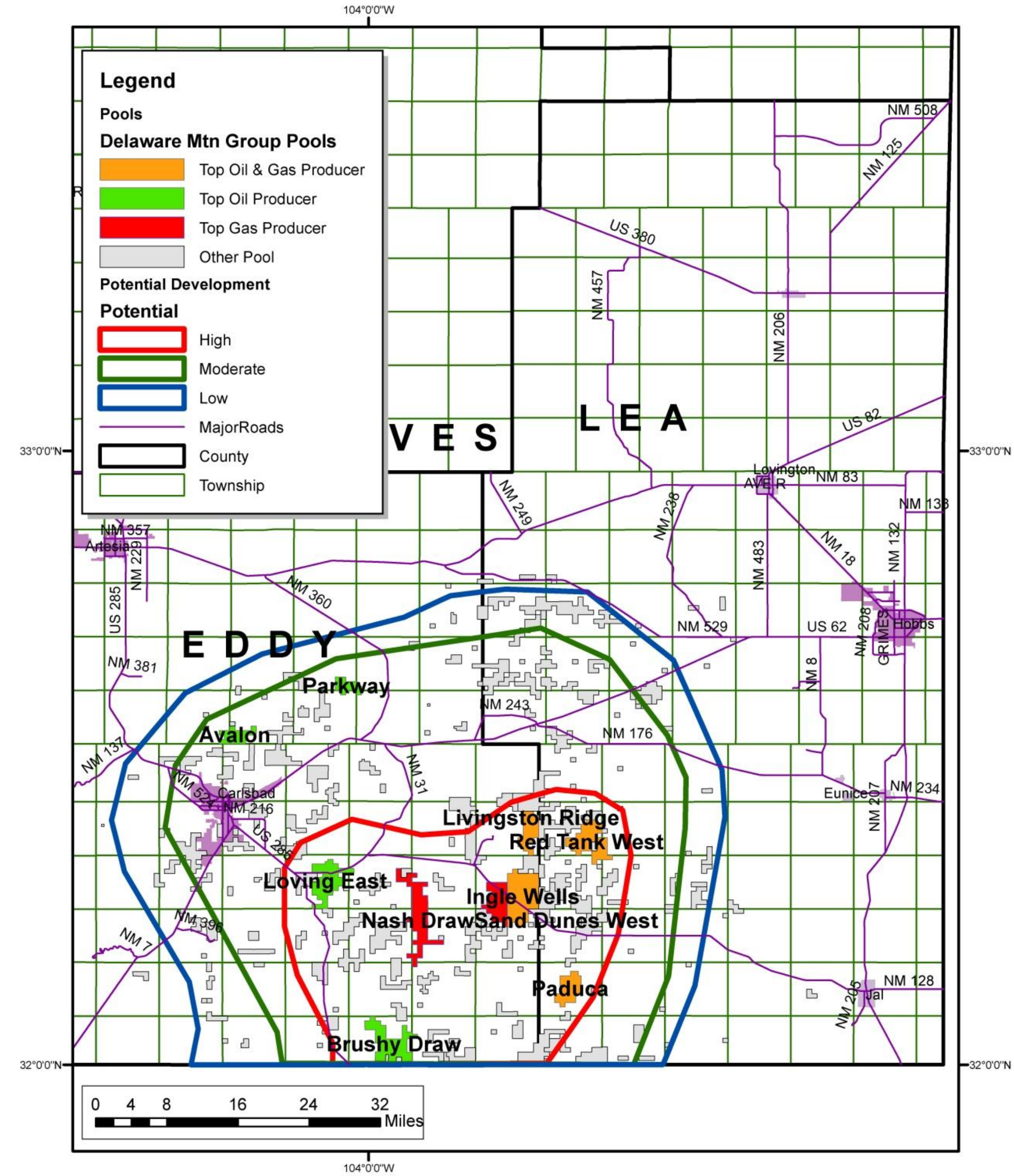


Figure 12. Potential map for the Delaware Sand play. Redline – high potential, green line – moderate potential, blue line – low potential

Ellenburger Karst-Modified Restricted Ramp Carbonate Play

The potential for future development is ***very low***.

BRIEF SUMMARY OF GEOLOGY

In New Mexico, the Ellenburger Formation is comprised of dolostones deposited in a restricted, shallow water marine environment as shown in the schematic in figure 1.

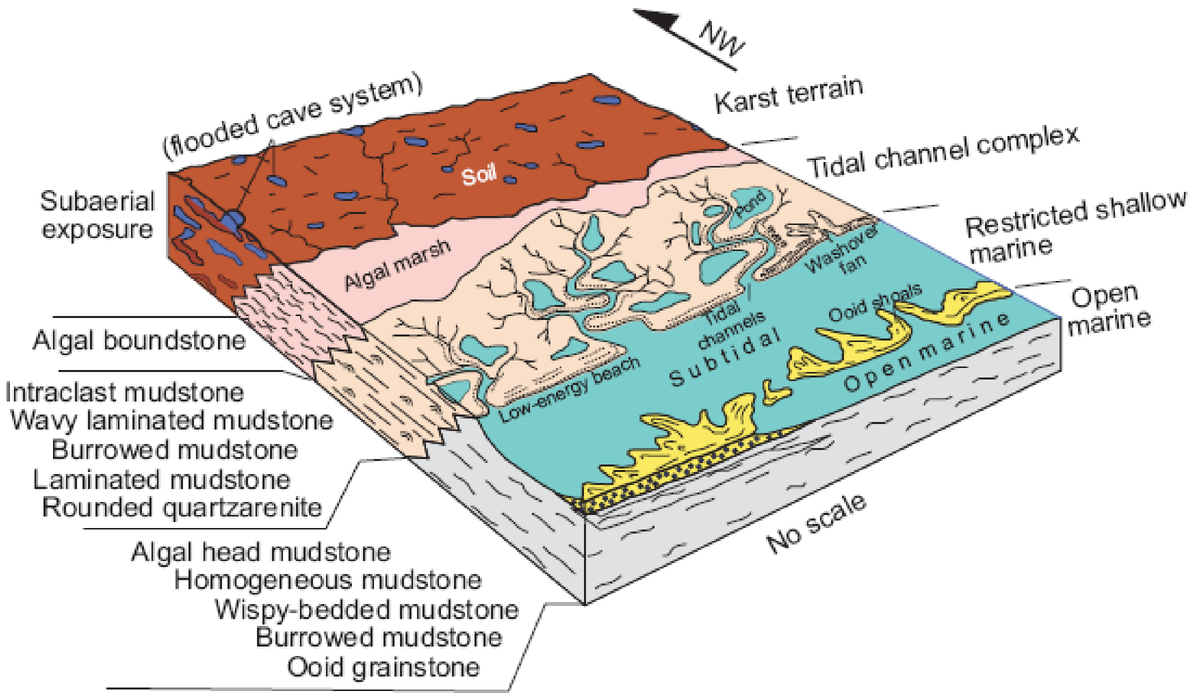


Figure 1. Depositional Model For Middle and Upper Ellenburger Sections (Loucks, 2006)

Porosity types include intercrystalline matrix, vugs, karst dissolution pores, and fractures. Secondary porosity from karst dissolution and collapse breccia is the most significant; while primary matrix porosity is generally low (<5%) (Loucks, 2006). Due to the fracture-type porosity, permeability can be moderate to high (one to a few hundred millidarcys), despite the low porosity. Table 1 lists petrophysical parameters for various Ellenburger rock types.

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water Saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil Saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Table 1. Petrophysical parameters of the Ellenburger group (Loucks, 2006)

The development of secondary porosity is the result of three major diagenetic processes: (1) dolomitization, (2) karsting, and (3) tectonic fracturing. (Loucks, 2006) Extensive subaerial diagenesis was associated with changes in relative sea level (Broadhead, et al, 2004).

The vast majority of Ellenburger fields are trapped in anticlinal or faulted anticlinal structures, with the seal the Simpson shales in the Central Basin Platform area. Subsequently, the Ellenburger reservoirs are mainly structural plays. (Figure 2)

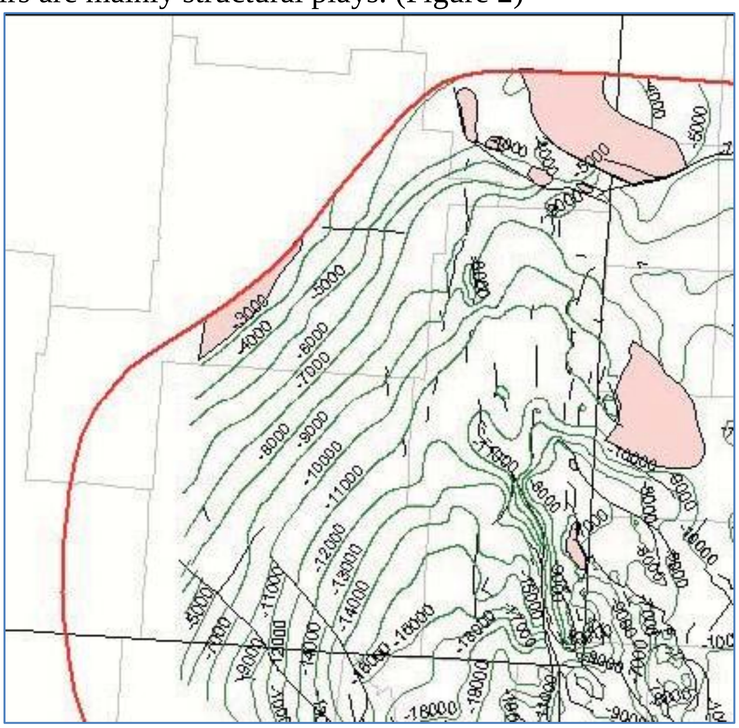


Figure 2. Structure map on top of Ellenburger group. (Loucks, 2006)

HISTORICAL DEVELOPMENT

Eighteen pools have produced ~68MMBO from the Ellenburger carbonate. The significant producing pools are located on the central basin platform of Lea County (figure 3). Initial discovery was in 1945 in the Dublin Ellenburger Field. The top seven pools (BRUNSON, FOWLER; JUSTIS; DOLLARHIDE; STATELINE; TEAGUE; and TEAGUE NORTH) comprise 95% of the total oil produced. The top pool is the Brunson Pool which has produced 27% or 40 MMBO of the total Ellenburger production.

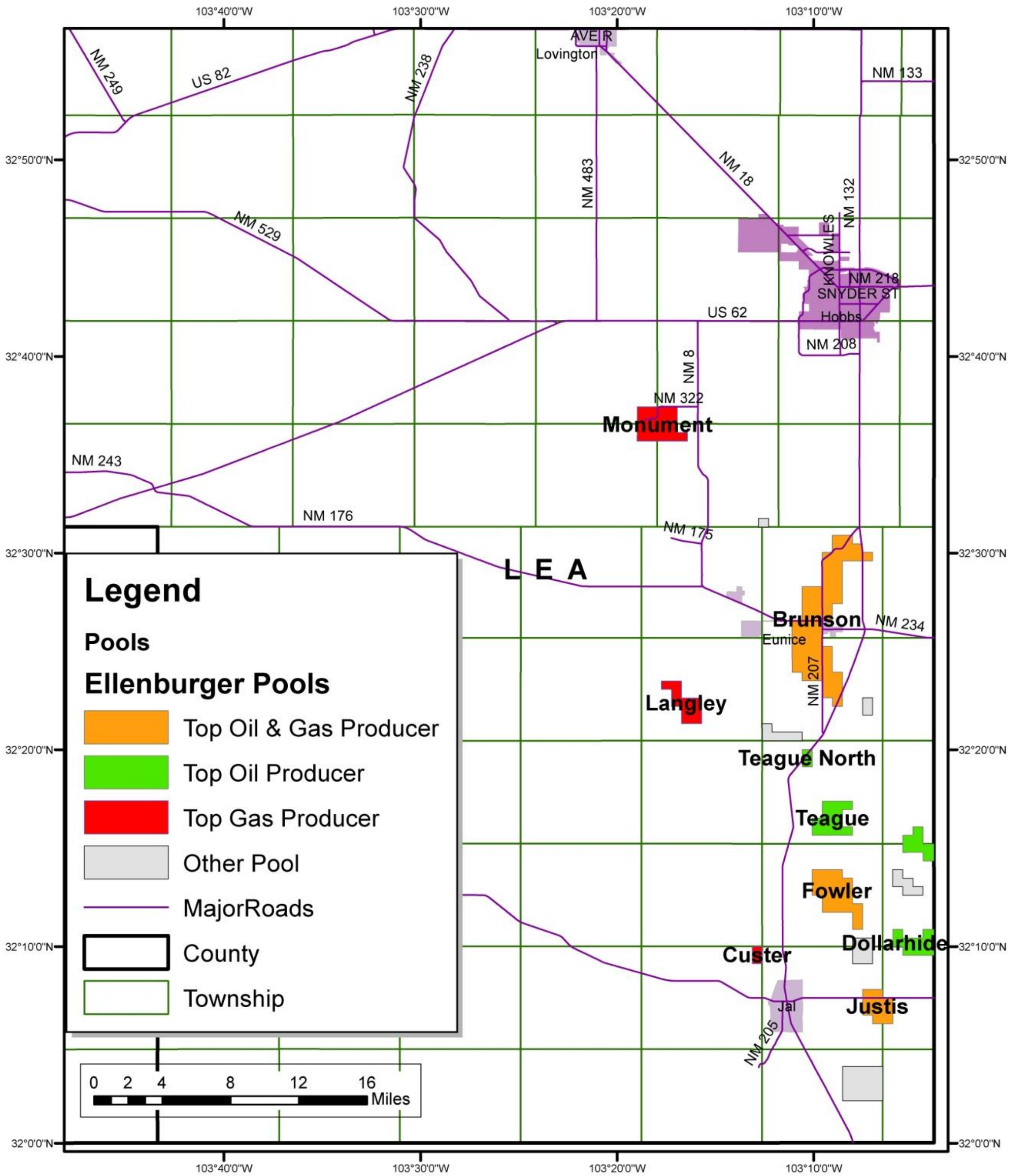


Figure 3. Play boundary and location of oil reservoirs in the Ellenburger Carbonate play

Peak production for the play occurred in 1953 at an annual average rate of 13,266 bopd. Since then the play has exhibited a declining trend in oil production with time (figure 4). For 2010 production averaged 56 bopd; with the majority from the Fowler (Ellenburger) Pool.

The reservoir drive mechanism is a combination of solution gas and water drive. As a result of the age of these reservoirs, all are either pressure depleted or have watered out due to the natural water drive. Figure 5 is an example from the second most prolific oil reservoir, Fowler (Ellenburger). Note the increasing WOR indicative of water encroachment.

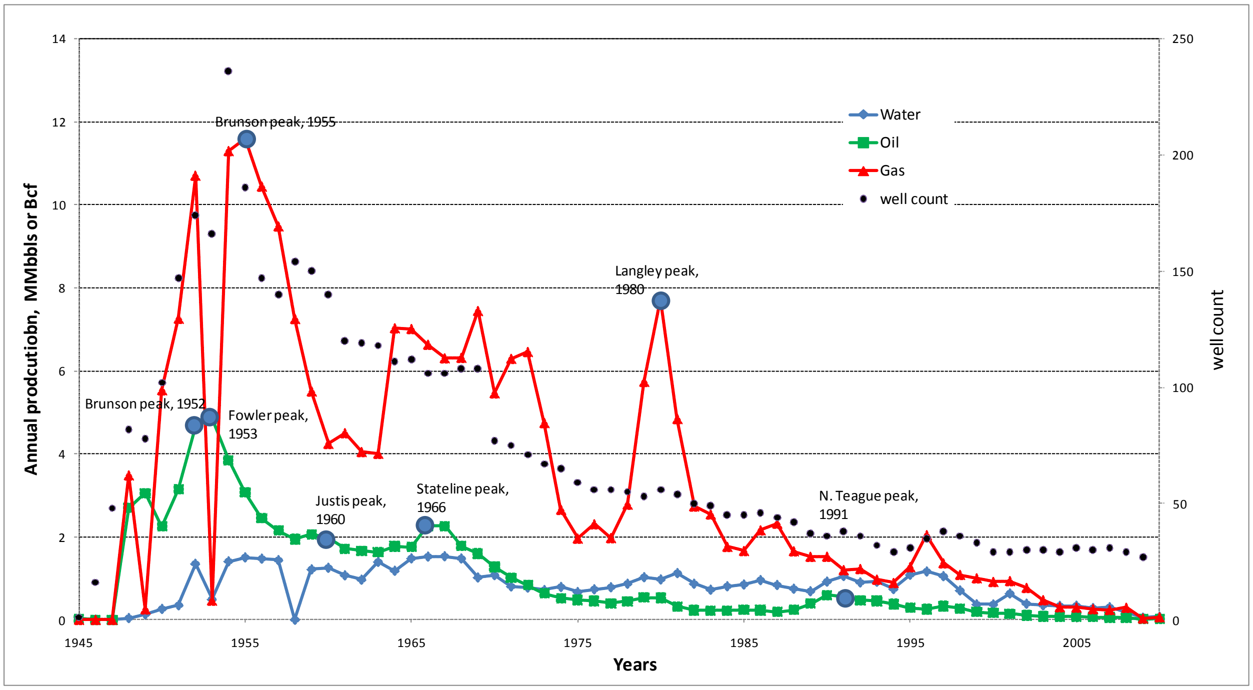


Figure 4. Ellenburger play annual oil, gas and water production. (Source: digitized data+ Dwights).

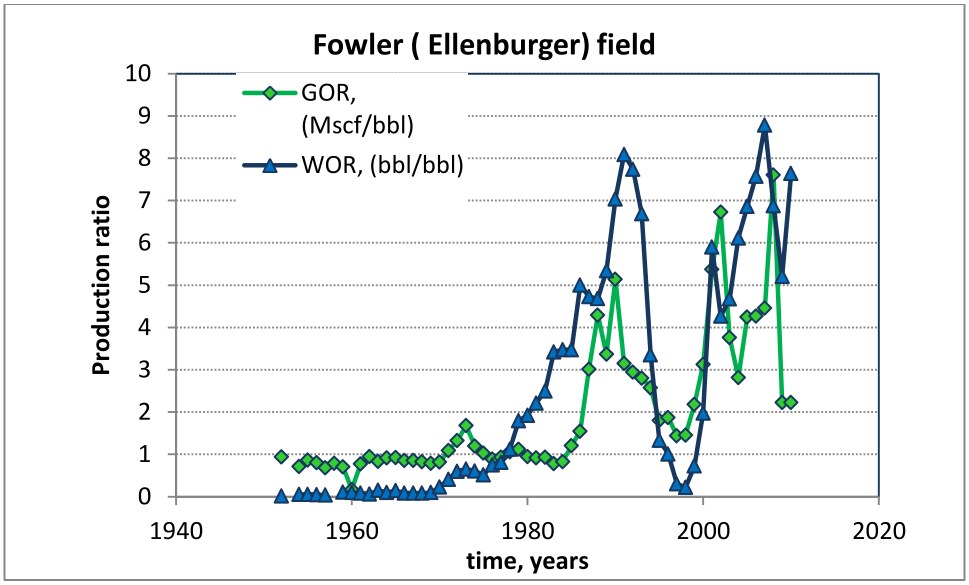


Figure 5. Annual WOR and GOR for Fowler (Ellenburger) Field. (Source: digitized data+ Dwights).

Cumulative water production has been 51.5 MMBW through 2010; resulting in a cumulative WOR of less than one. Cumulative gas production has been 227 Bscf; the majority is associated gas; however, several pools are categorized as gas pools; North Bell Lake, Langley and Custer (Ellenburger) are several of the largest gas pools.

FUTURE DEVELOPMENT

Limitations

The limiting factors in further developing the Ellenburger are:

1. Areally confined to the central basin platform and sporadicly in the northwest shelf area; thus does not have widespread potential
2. Only 27 wells active in the entire play in mainly old, well-established pools. Only one well has been drilled as a new Ellenburger completions in the last 6 years.
3. With regards to most other oil and gas plays the Ellenburger is a deep target, thus not considered an uphole potential zone
4. As old wells, potential well integrity problems limit their usefulness

Potential improvement

Redevelopment in existing fields was not observed and thus is not anticipated in the future. Recent activity has been confined to the Ellenburger Fields in West Texas for redevelopment and potential for EOR (ARI, 2006). Studies (kerans 1988) in West Texas Ellenburger fields have reported significant spatial complexity within the reservoirs, thus horizontal wells may be an option for improving recovery. This variability can result in adjacent wells with significant differences in production, anywhere from 0 to 900,000 BO.

A likely future use for the Ellenburger is as salt water disposal wells.

Fusselman Shallow Platform Carbonate Play

The potential for future development is ***very low***.

Brief Summary of Geology

The Fusselman Formation of the Permian Basin consists of shallow-water normal marine carbonates sediments that were deposited on a regionally extensive, relatively stable platform along the southern margin of the Laurentian paleocontinent during the Late Ordovician to Early Silurian (Ruppel, 2006). The similarity of depositional facies across the region, and indeed much of the southwest, indicates that conditions were relatively uniform over great distances.

The Fusselman attains maximum thicknesses of more than 600 ft in southeasternmost New Mexico and far West Texas and thins eastward (fig. 1). Reservoirs are developed principally in basal ooid grainstones and overlying pelmatozoan packstones, both of which are areally extensive. In New Mexico the formation is largely of shallow water origin, dolomitized, and often brecciated (Broadhead, et al, 2004). Porosity development is largely associated with original interparticle porosity in ooid grainstones. Secondary porosity from leaching of carbonate mud fractions in pelmatozoan packstones is also present. Evidence of karst processes, ranging from large, cave-fill successions to minor dissolution features, is locally apparent across the Permian Basin (Ruppel and Holtz, 1994). Differentiation of the Fusselman from the bounding Montoya Formation and Wristen Group is difficult in New Mexico due to the similar dolostone content of each (Broadhead, et al, 2004).

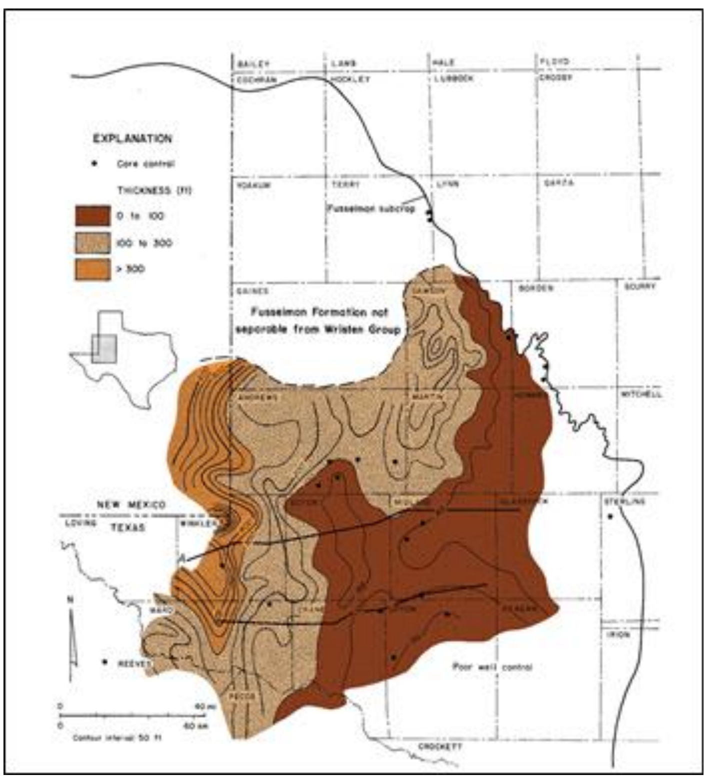


Figure 1. Thickness of Fusselman Formation in the Permian Basin. From Ruppel (2006).

HISTORICAL DEVELOPMENT

Twenty-five pools have produced 65MMBO from the Fusselman carbonate. The pools are located east of the play boundary; with sporadic development in southern Roosevelt, Eastern Chaves, and Northern Lea counties and more concentrated development on the central basin platform of Lea County (figures 2 and 3). Initial discovery was in 1947 in the McCormack Silurian Field just north of Eunice on the central basin platform. The top seven pools (East Caprock Devonian, Justis Fusselman, Justis Montoya, North Justis Fusselman, South Peterson Fusselman, Dollarhide Devonian and Bough Devonian) comprise 83% of the total oil produced. The top pool is East Caprock which has produced 34% or 22MMBO of the total Fusselman production.

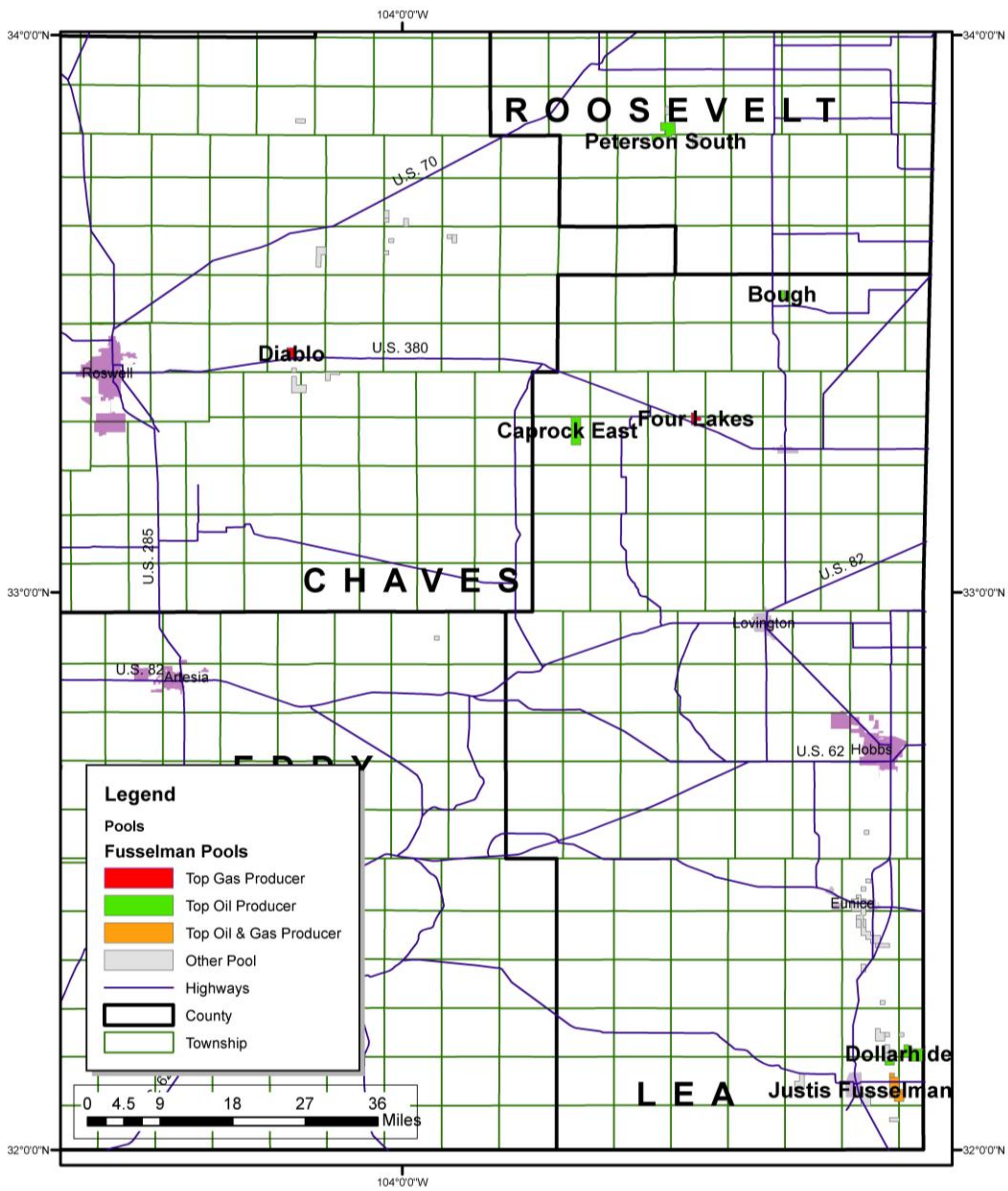


Figure 2. Fusselman play map for Southeast New Mexico

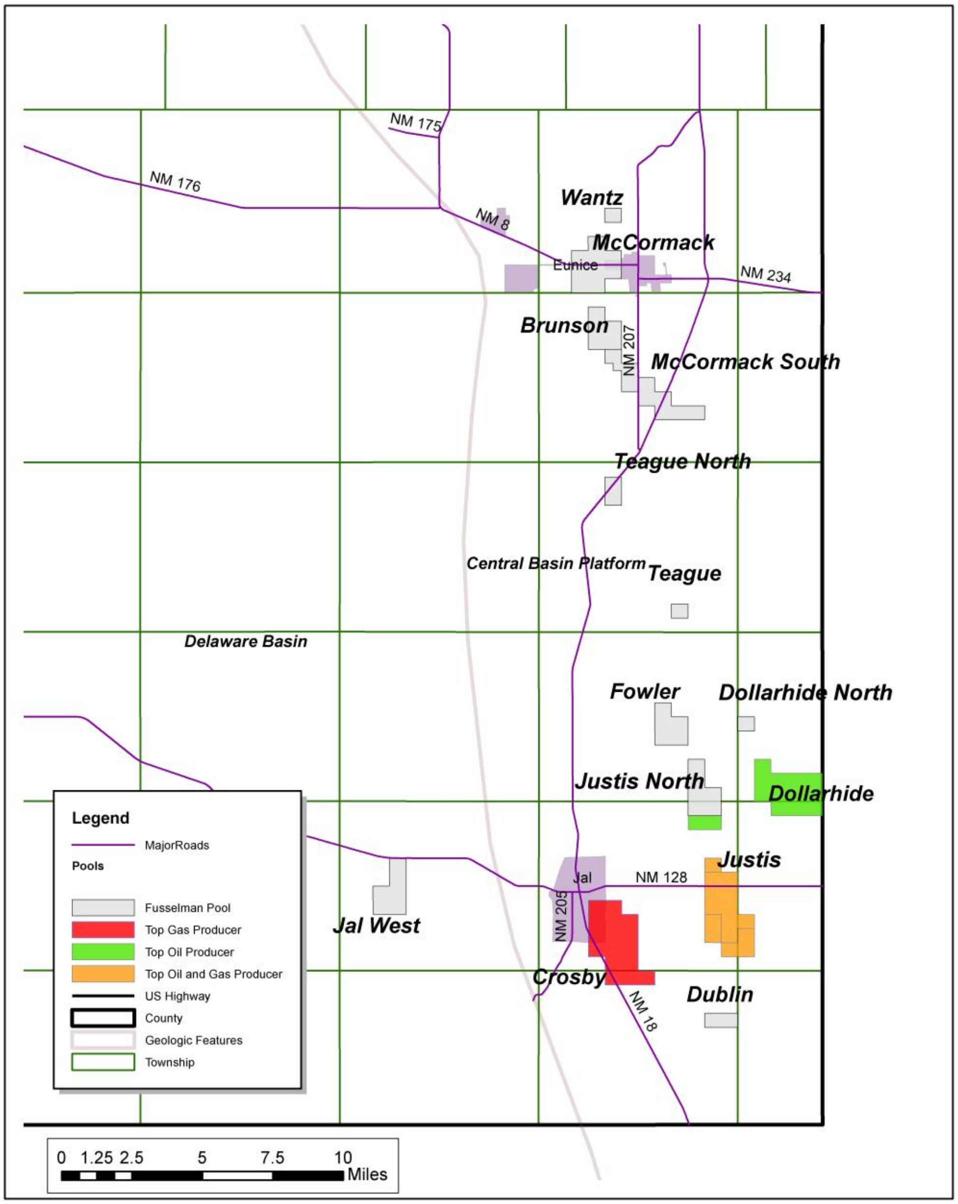


Figure 3. Expanded pool map indicating the top Fusselman pools in the CBP.

Peak production for the play occurred in 1964 at an annual average rate of 7,118 bopd. Since then the play has exhibited a declining trend in oil production with time (figure 4). For 2009 production averaged 447 bopd; the majority from the South Peterson and Justis Fusselman Pools.

Since the trapping is typically structurally controlled, downdip water is typically encountered and results in very active water drive in many pools. Figure 5 is the production curve for the East Caprock Devonian Pool; the most prolific oil pool in this play. Note the excessive water cut and watering out due to the encroaching water.

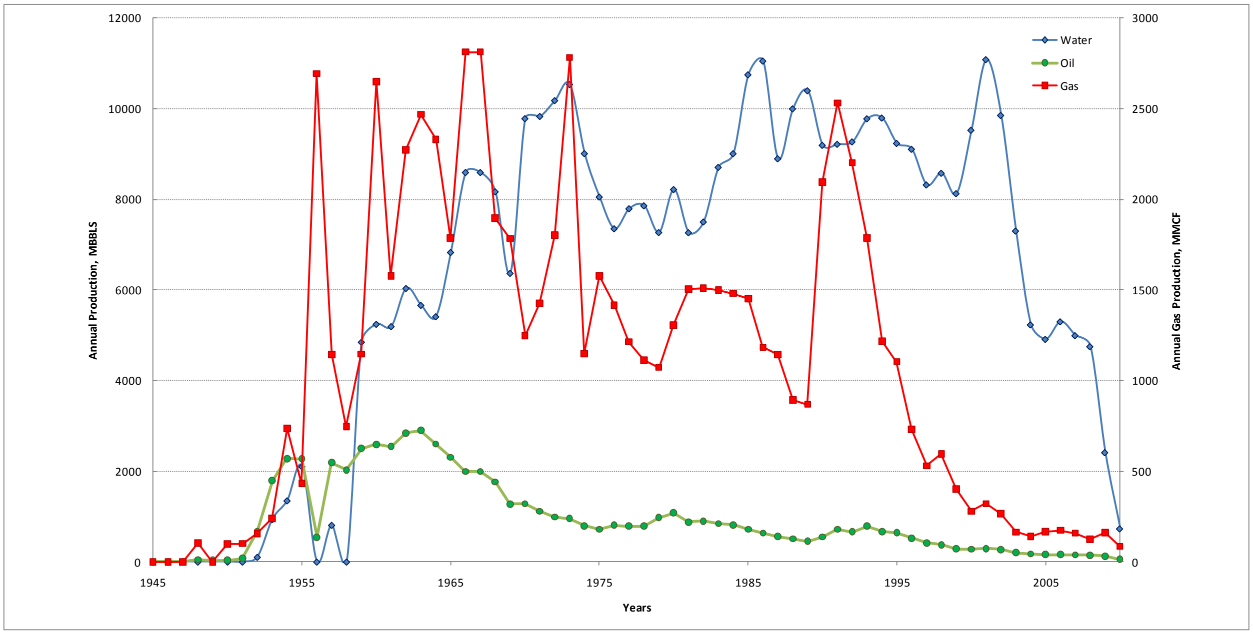


Figure 4. Fusselman play annual oil, gas and water production. (Source: digitized data+ Dwights).

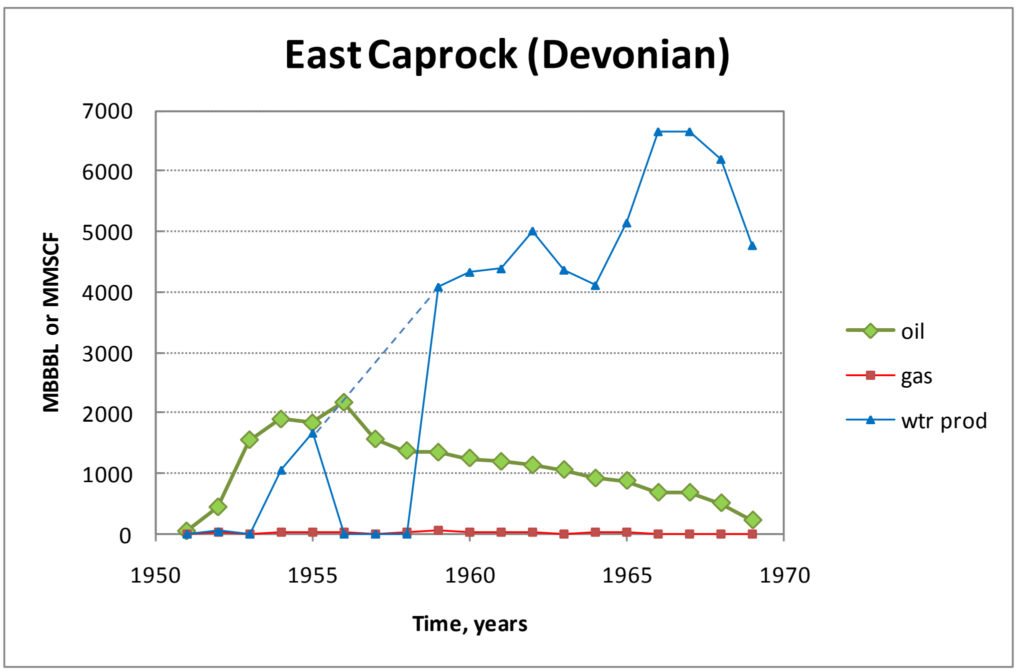


Figure 5. annual oil, gas and water production for East Caprock (Devonian). (Source: digitized data).

Cumulative water production has been 226 MMBW through 2010; resulting in a cumulative WOR of slightly less than 4 to 1. Cumulative gas production has been 73 Bscf; the majority is associated gas; however, several pools are categorized as gas pools; Four Lakes (Devonian) is the largest of these gas pools.

Due to the natural water drive the Fusselman has not been a strong candidate for waterflooding or EOR. In the few pools that have attempted waterflooding the results were poor. An example is the Diablo Field shown in Figure 6. Note, no waterflood response is observed after water injection commenced. The benefit from water injection is most likely the disposal of the high volumes of water and thus make this play a potential candidate for salt water disposal.

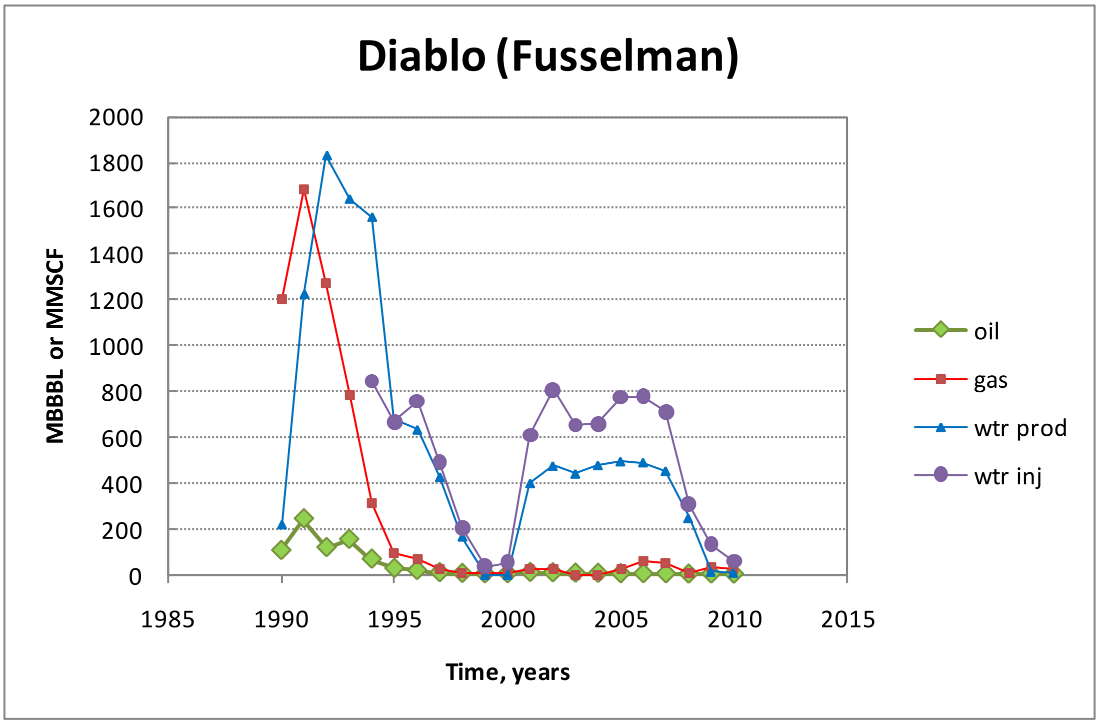


Figure 6. Annual production and injection for the Diablo (Fusselman) Pool

Future Development

Limitations

The limiting factors in further developing the Fusselman are:

1. Limited extent. Most significan reservoirs are confined to the central basin platform, with a few sporadic occurrences in the northwest shelf area; thus the Fusselman does not have widespread potential.
2. It is an old, and poorly documented play. Only 122 wells are active in the entire play in mainly old, well-established pools. Sixteen wells have been completed in the Fusselman since 2004 (1-chaves, 8-lea, 7-Roosevelt), with the Tule Montoya Field the most active with 5 new wells.
3. With regards to most other oil and gas plays the Fusselman is a deep target, thus not considered an uphole potential zone
4. Because wells are old, potential well integrity problems limit their usefulness.

Potential improvement

Redevelopment in existing fields was not observed and thus is not anticipated in the future. With the application of 3D seismic and other tools, additional small discoveries are possible in Northern Lea, Chaves and Roosevelt counties; where the geology is more complex. Latest activity seems to confirm this possibility; however, the likelihood of gas will defer this development.

The installation of a submersible pump significantly increased the fluid production in South Peterson Field. This work resulted in additional oil production and thus extends the well life. It also increases water production and subsequently an increase in disposal is needed. Duplicating this work will require additional water disposal capabilities.

Leonard Restricted Platform Carbonate Play

Future development is very high for this play due to the significant Yeso oil development in Eddy county, and continued gas/oil development in mature pools in Lea county.

BRIEF SUMMARY OF GEOLOGY

Reservoirs of the Leonard Restricted Platform Carbonate play are divided into four stratigraphic units (Figure 1). From descending order they are: Upper Yeso (Paddock and Glorieta Formations), Blinebry , Leonard Tubb, and Leonard Drinkard. Most of these reservoirs are productive from platform dolostones and limestones but some are productive from sandstones.

The play has been divided into two geographic regions; the Central Basin Platform subplay and the Northwest Shelf subplay, respectively (Figure 2).

Production from the four stratigraphic units is mostly from stacked reservoirs on the Central Basin Platform. On the Northwest Shelf, production from the lower three units is only in the Eastern part of the trend.

Most reservoirs in the Leonard Restricted Platform Carbonate play are marine limestones and dolostones deposited on a restricted carbonate-dominated platform. Carbonate reservoirs dominate the Drinkard, Blinebry, and Paddock sections. Fine=grained dolomitic sandstone reservoirs are dominant in some areas in the Tubb and Glorieta sections but dolostone reservoirs are dominant elsewhere in the Tubb and Glorieta.

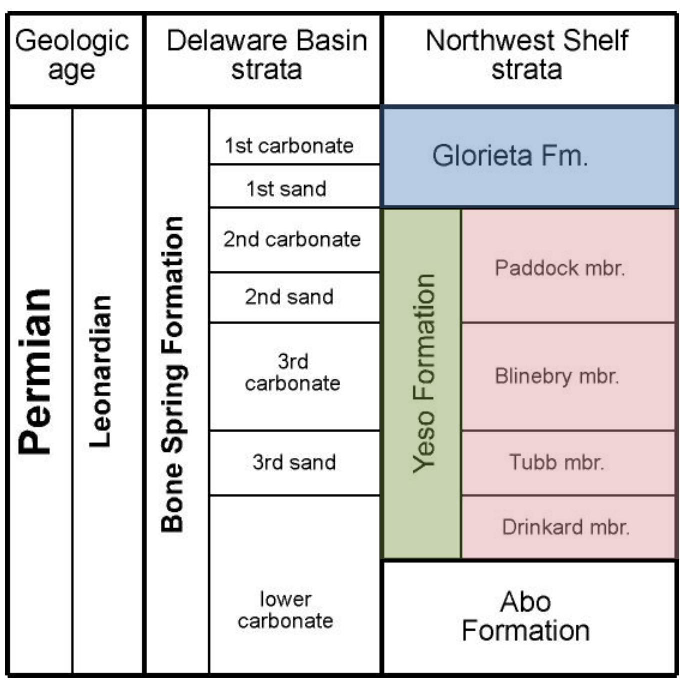


Figure 1. Stratigraphic chart showing correlation of Yeso strata on the Northwest

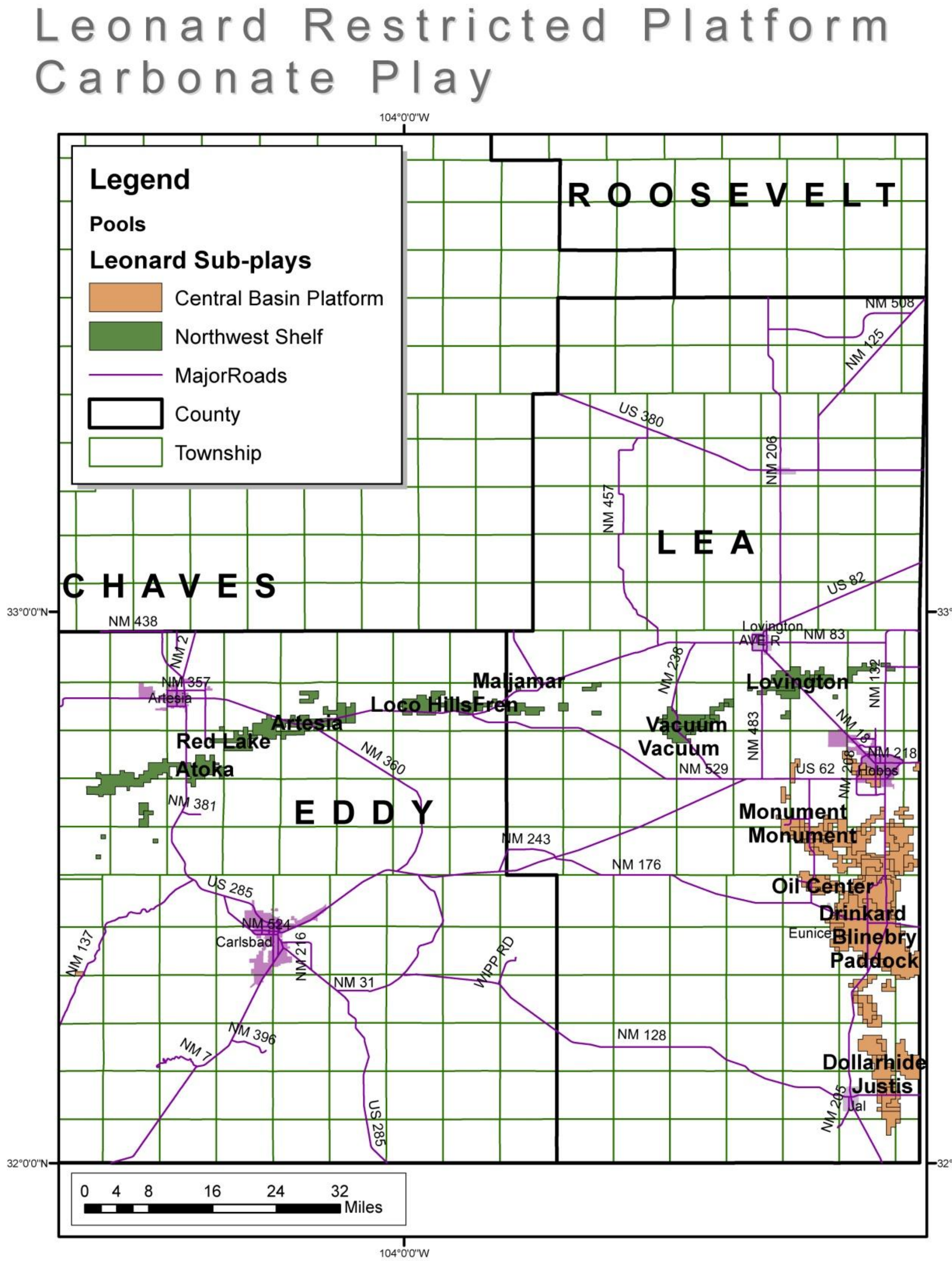


Figure 2. Play map for the Leonard Restricted Platform Carbonate play. The Central Basin Platform and Northwest shelf subplays are identified.

Upper Yeso (Paddock and Glorieta Formations)
The distinction between Glorieta and Paddock is not well defined, therefore some classifications of production in Glorieta is really Paddock. Nevertheless, the Upper Yeso subplay is the most productive subplay in NM. Dolostone reservoirs are dominant in some areas of the Glorieta, while in other areas dolomitic fine-grained sandstones are dominant. Sandstone trend percentages increase westward.

Leonard Drinkard
Drinkard reservoirs are productive from carbonates deposited in a variety of shelf and shelf-edge environments. Reservoir characteristics are dependent upon underlying Abo trend on Northwest Shelf. For this play, traps are generally formed by low-relief anticlines. Vertical variations in rock properties (from seal to reservoir and so on) lead to multiple pay zones. Consequently, all four subplays can be productive in a single well. Similarly, facies variations can create porosity pinchouts and internal compartmentalization.

Historical Development

The discussion on the development history is separated into two focus areas, the Central Basin Platform and the Northwest Shelf. The Northwest shelf area first produced in 1950 from the Maljamar (Paddock) pool (see figure 3). Not until 1963, with the discovery of the Vacuum (Glorieta) pool, did production significantly increase. As seen in Table 1, the Vacuum (Glorieta) pool is the top cumulative producing pool at 83 MMBO or 57% of the total production. Location of the top producing pools is shown in Figure 4.

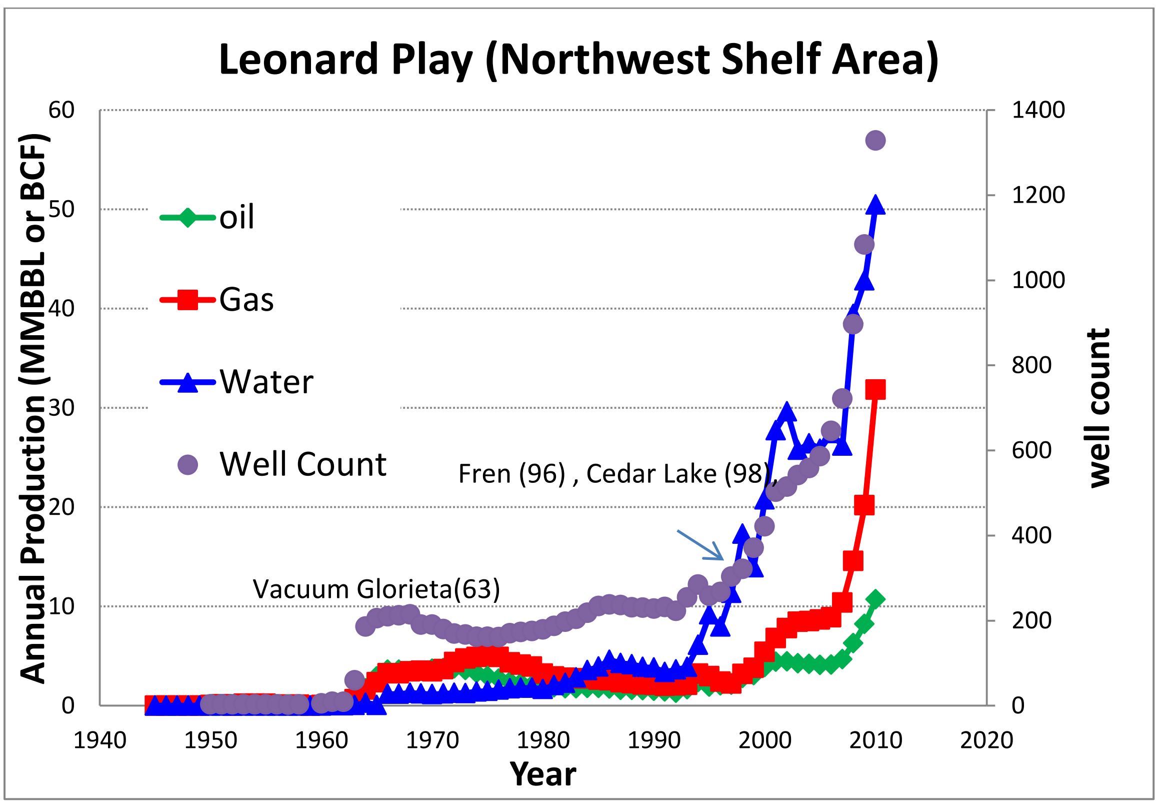


Figure 3. Annual production and well count for the Northwest Shelf area of the Leonard Play. (Data source: Digitized+dwights)

poolName	Cum_Oil, MMBO	percent	Cum %	Yr-1st prod
VACUUM;GLORIETA	82.88	57%	57%	1963
LOCO HILLS;YESO / GLORIETA	24.52	17%	73%	1997
CEDAR LAKE; YESO	8.26	6%	79%	1998
VACUUM;DRINKARD	6.03	4%	83%	1992
MALJAMAR;PADDOCK #	5.39	4%	87%	1950
ATOKA;GLORIETA	4.65	3%	90%	1977
FREN;PADDOCK**	3.52	2%	92%	1996
ARTESIA;YESO*	2.06	1%	94%	1998
VACUUM;BLINEBRY	1.78	1%	95%	1969
ARTESIA;GLORIETA*	0.90	1%	96%	1998

* Artesia (Yeso) and Artesia (Glorieta) now combined as Artesia (Glorieta-Yeso)

** Fren (Paddock) renamed Fren (Yeso)

\# Maljamar (Paddock) renamed Maljamar (Yeso)

Table 1. Top cumulative oil producing pools for the Northwest Shelf area of the Leonard Play. (Data source: digitized + Dwights)

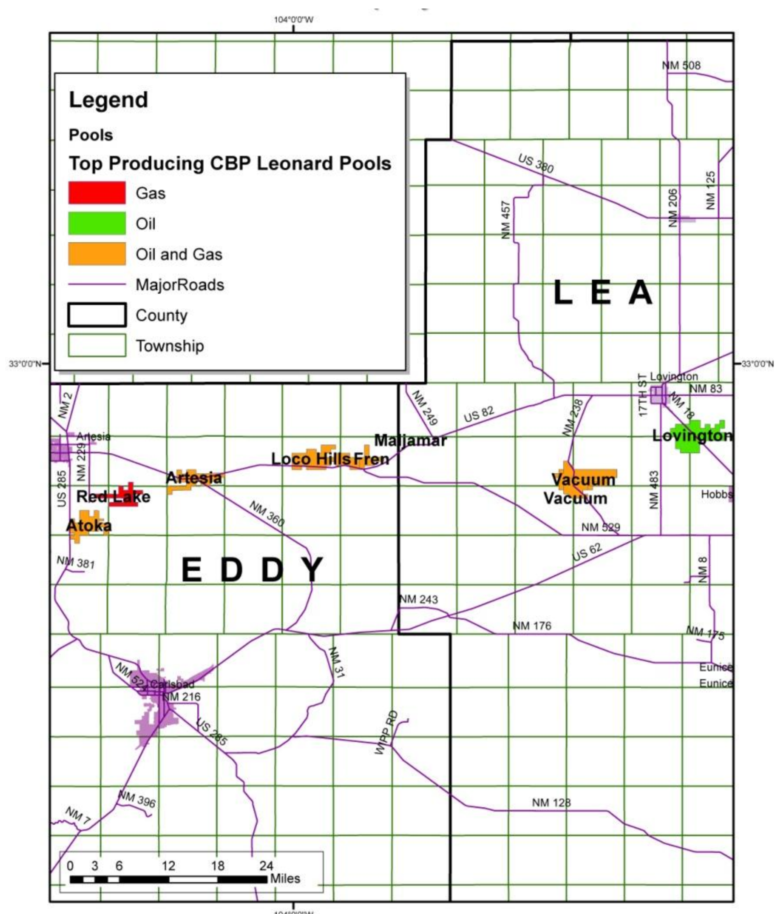


Figure 4. Location of top cumulative producing pools for the Northwest Shelf subplay.

Observe in Figure 3, recent activity has resulted in a significant increase in production. Since the late 1990s, eight pools have been discovered or existing pools extended and infilled. As an example, the Loco Hills (Yeso/Glorieta) pool has become the top producing pool in 2010. For this pool, since 1997 well count has increased from zero to over 450 (Figure 5). During the same time oil production has increased to over 9,500 BOPD (see Table 2) with a corresponding WOR of 3:1.

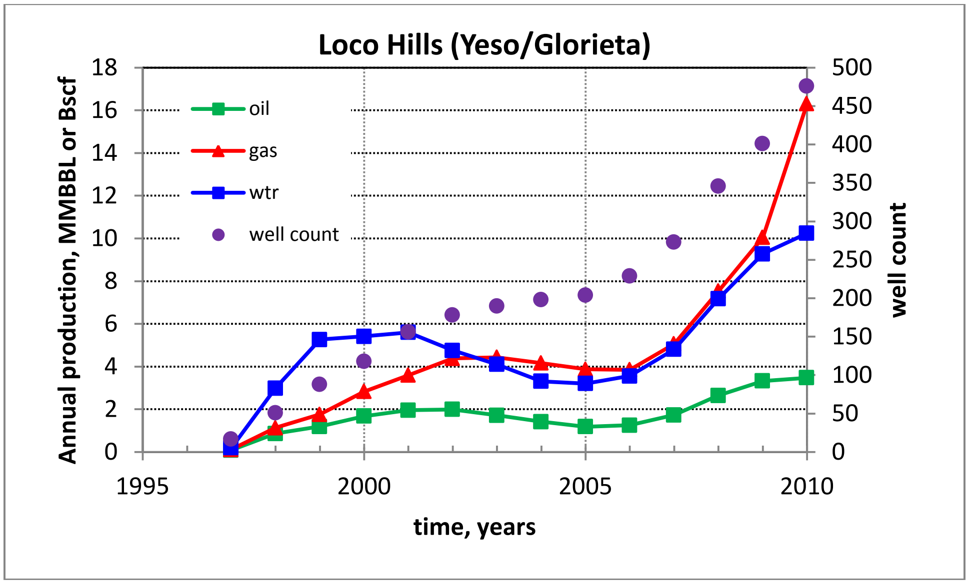


Figure 5. Annual production and well count for the Loco Hills (Yeso/Glorieta) Pool. (Data source: GOTECH)

poolName	2010 oil prod BOPD	horizontal wells	2010 WOR	water flood
LOCO HILLS;YESO / GLORIETA	9531	9	2.9	Y
MALJAMAR;PADDOCK	5393	2	5.2	
FREN;PADDOCK	3675	2	6.9	
CEDAR LAKE; YESO	2672	4	3.8	
VACUUM;GLORIETA	1626	24	17.0	Y
ARTESIA;YESO	1261		3.1	
SEVEN RIVERS NORTH;YESO / GLORIETA	1072	6	1.3	
CEMETARY; YESO	826		2.0	
EMPIRE;YESO / GLORIETA	726	1	4.1	
EMPIRE EAST;YESO / GLORIETA	722		3.0	

Table 2. Top 2010 oil producing pools for the Northwest Shelf area of the Leonard Play. (Data source: digitized + Dwights)

Associated gas production has also been significant, with 246 Bscf of gas produced for the play. Vacuum (Glorieta) has produced 36% or 90 Bscf of the gas (Table 3); however, Loco Hills is the highest gas producing pool in 2010 at a little less than 45 MMscfd (Table 4).

poolName	Cum_gas, Bscf	percent	Cum %
VACUUM;GLORIETA	89.86	36%	36%
LOCO HILLS;YESO / GLORIETA	69.10	28%	64%
CEDAR LAKE; YESO	17.56	7%	72%
ATOKA;GLORIETA	15.25	6%	78%
MALJAMAR;PADDOCK	12.92	5%	83%
VACUUM;DRINKARD	10.30	4%	87%
FREN;PADDOCK	7.73	3%	90%
VACUUM;BLINEBRY	6.24	3%	93%
ARTESIA;YESO	4.46	2%	95%
RED LAKE;GLORIETA	2.45	1%	96%

Table 3. Top cumulative gas producing pools for the Northwest Shelf area of the Leonard Play. (Data source: digitized + Dwights)

poolName	2010 gas prod MCFD
LOCO HILLS;YESO / GLORIETA	44671
MALJAMAR;PADDOCK	13174
FREN;PADDOCK	8062
CEDAR LAKE; YESO	7611
ARTESIA;YESO	3062
EMPIRE;YESO / GLORIETA	1886
EMPIRE EAST;YESO / GLORIETA	1179
ATOKA;GLORIETA	1116
SEVEN RIVERS NORTH;YESO / GLORIETA	1039
RED LAKE;GLORIETA	925

Table 4. Top 2010 gas producing pools for the Northwest Shelf area of the Leonard Play. (Data source: digitized + Dwights)

The Central Basin Platform area began production in 1945 from the Paddock and Drinkard pools (see figure 6). Cumulative production through 2010 has been 404 MMBO and 4.6 Tcf of gas. Initially developed for oil, the pools in this subplay are more prolific gas producers. As seen in Figure 7, peak gas production was delayed and significant. The top oil and gas producing pools for this subplay are listed in Tables 5 and 6. Notice Drinkard and Blinebry pools dominate both oil and gas production.

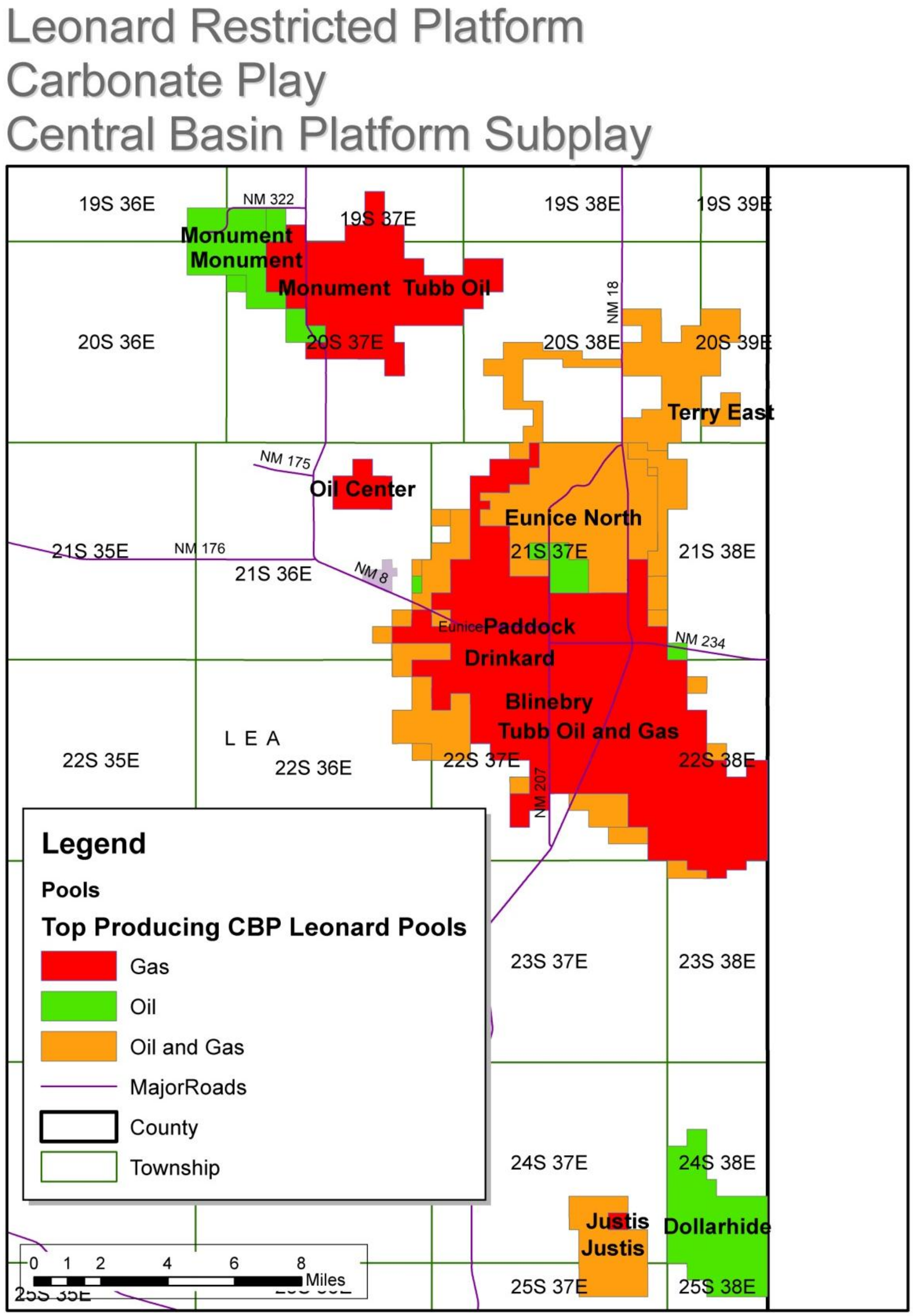


Figure 6. Location of top cumulative producing pools for the Central Basin Platform subplay.

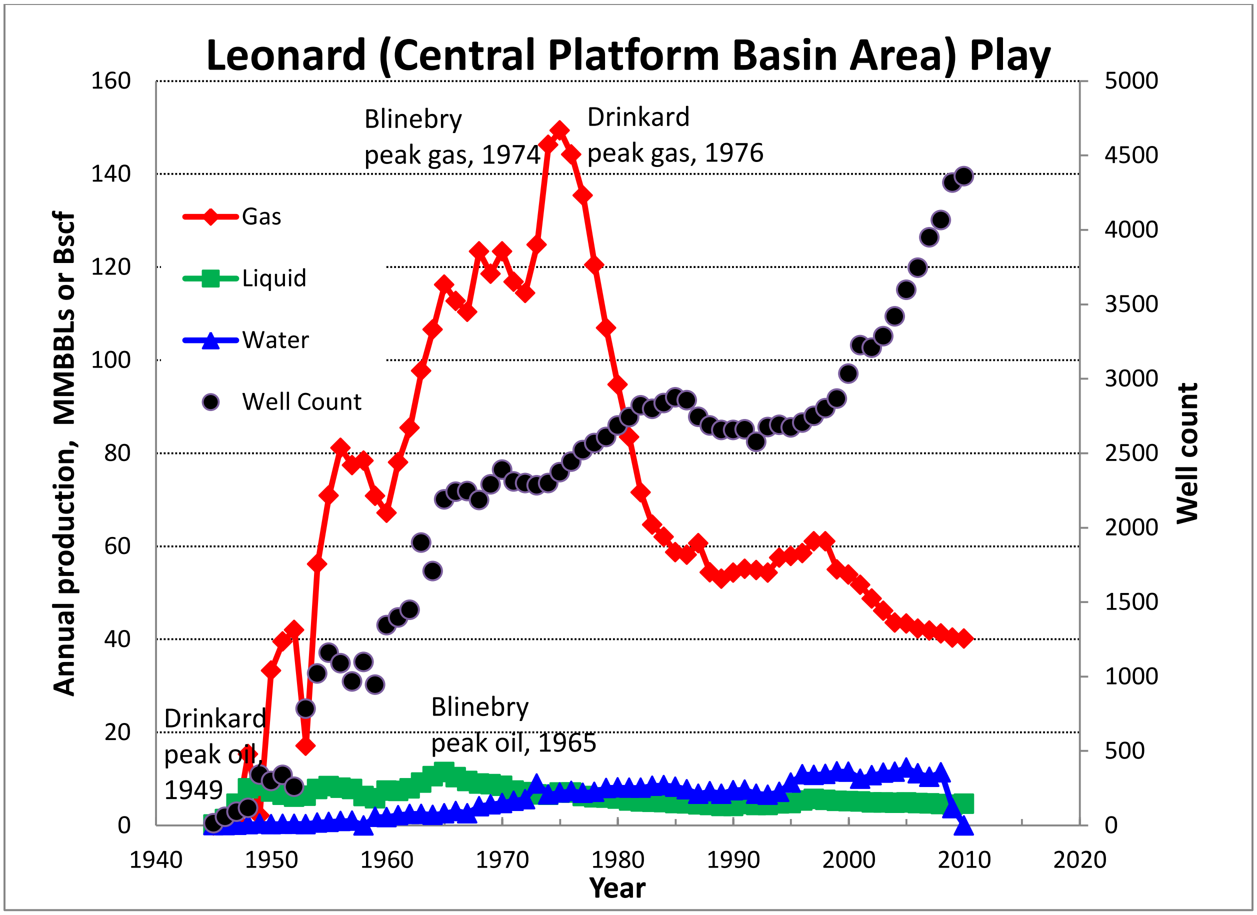


Figure 7. Annual production and well count for the CBP area of the Leonard Play. (Data source: Digitized+dwights)

poolName	Cum_Oil MMBO	percent of total	Cumulative %
DRINKARD;DRINKARD	89.3	22%	22%
BLINEBRY;BLINEBRY	45.7	11%	33%
JUSTIS;BLINEBRY	36.9	9%	42%
PADDOCK;PADDOCK	31.8	8%	50%
DOLLARHIDE;TUBB/DRINKARD	27.4	7%	57%
LOVINGTON;PADDOCK	19.1	5%	62%
EUNICE NORTH;BLINEBRY / TUBB / DRINKARD	17.0	4%	66%
MONUMENT;PADDOCK	10.7	3%	69%
MONUMENT;BLINEBRY	10.2	3%	71%
TERRY EAST;BLINEBRY	9.7	2%	74%

Table 5. Top cumulative oil producing pools for the Northwest Shelf area of the Leonard Play. (Data source: digitized + Dwights)

poolName	Cum_Gas Bscf	percent of total	Cumulative %
BLINEBRY;BLINEBRY	1284	28%	28%
DRINKARD;DRINKARD	1011	22%	50%
TUBB;TUBB	589	13%	63%
EUNICE NORTH;BLINEBRY / TUBB /	240	5%	68%
JUSTIS;BLINEBRY	239	5%	74%
BRUNSON SOUTH;DRINKARD	161	4%	77%
PADDOCK;PADDOCK	144	3%	80%
TERRY EAST;BLINEBRY	91	2%	82%
MONUMENT;TUBB	90	2%	84%
JUSTIS;GLORIETA	82	2%	86%

Table 6. Top cumulative gas producing pools for the Northwest Shelf area of the Leonard Play. (Data source: digitized + Dwights)

Figure 8 displays the Drinkard production history. Initially a dominate oil pool it later became the second largest gas pool for this play. The response to waterflooding commencing in the mid-1970s can be observed.

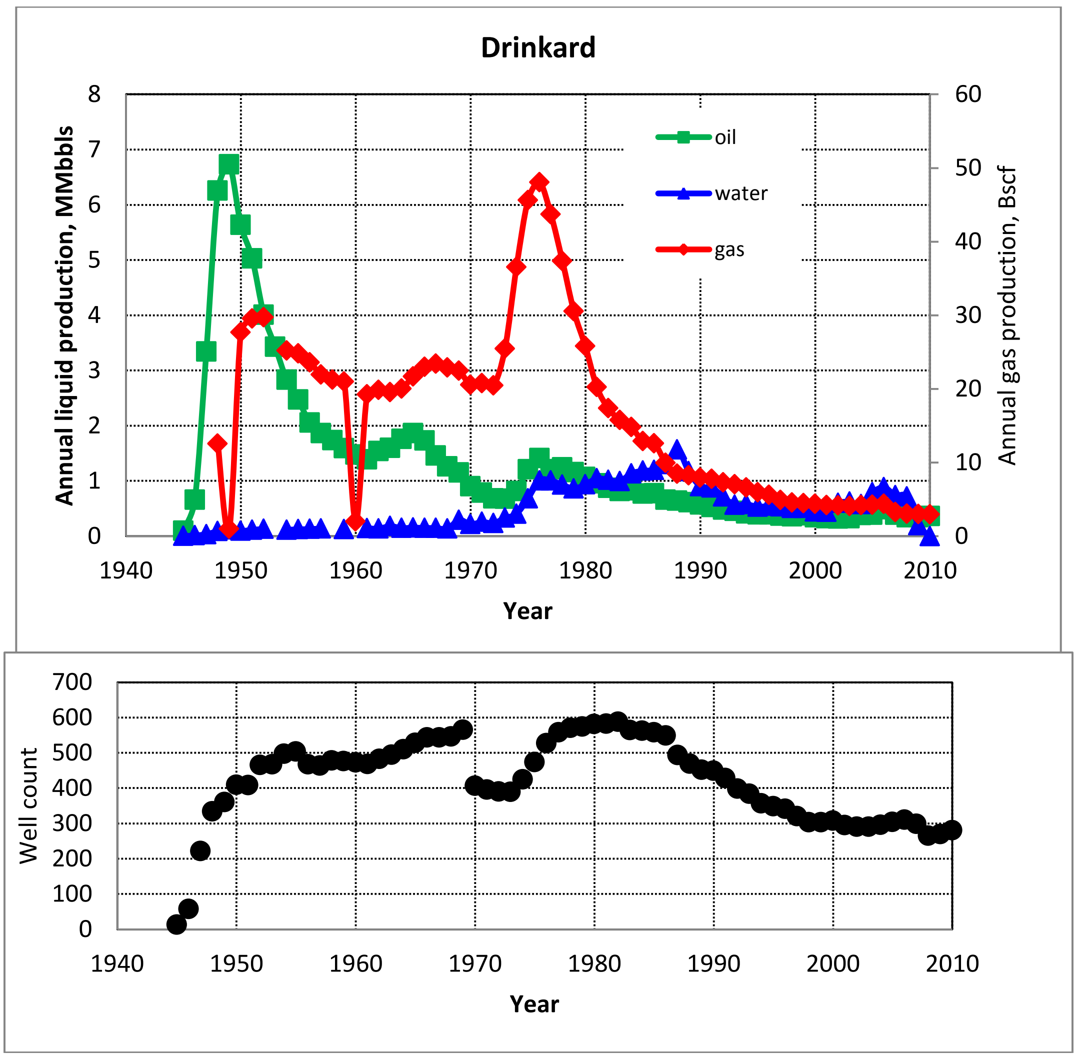


Figure 8. Drinkard pool performance. (Data Source: digitized + Dwights)

Blinebry production history is shown in Figure 9. Observe for a 15 year period from 1963 to 1977 this pool averaged 36 Bscf per year (slightly less than 100,000 MCFD).

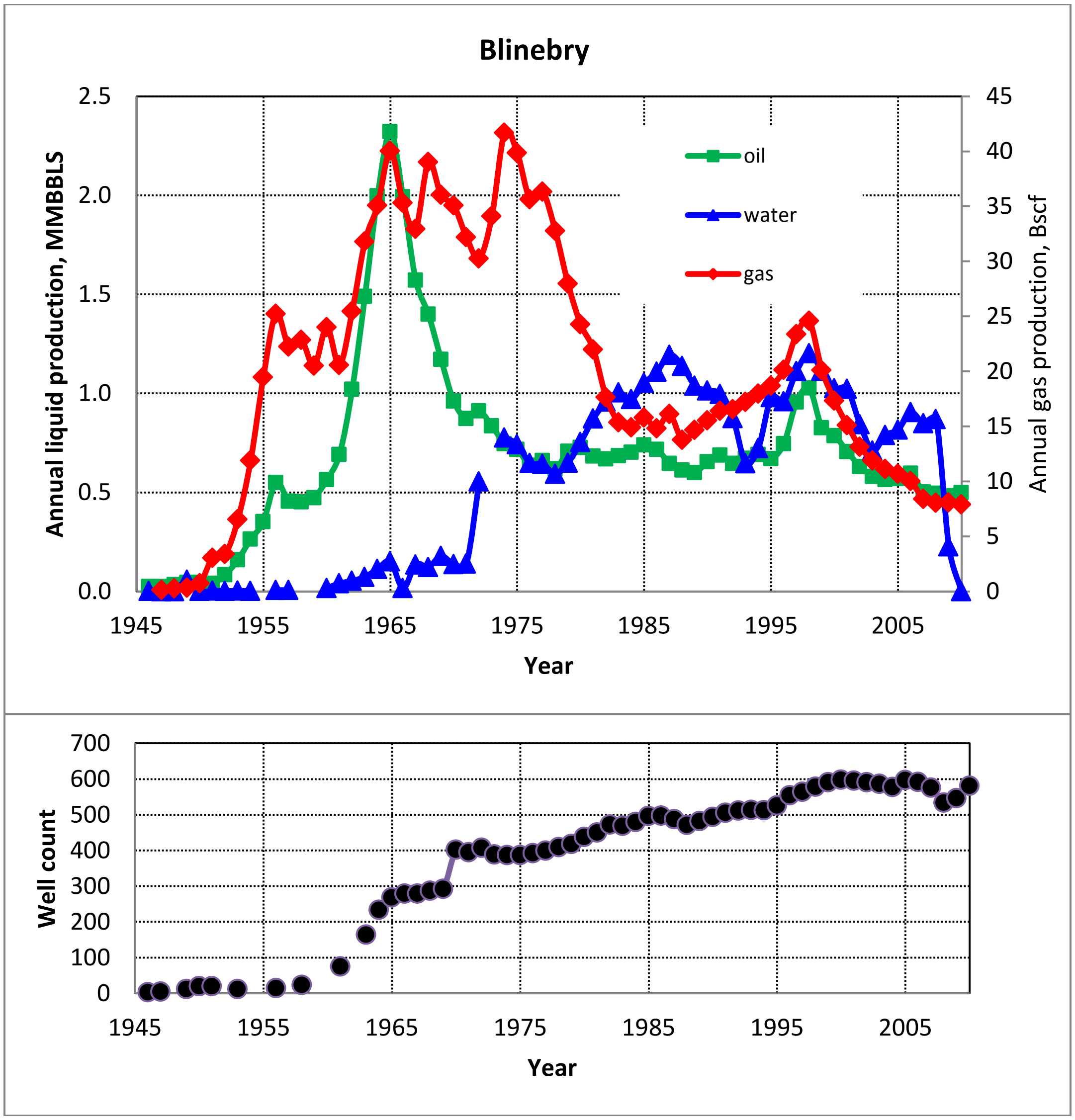


Figure 9. Blinebry pool performance. (Data Source: digitized + Dwights)

Top 2010 oil production rate (Table 7) and gas rate (Table 8) has been lead by recent development in the North Eunice (Blinebry/Tubb/Drinkard) pool. As shown in Figure 10, expansion of waterflood operations in the late 1990s and additional infill well development subsequent to this expansion, has lead to significant production increases in both oil and gas.

poolName	2010 oil rate BOPD	2010 WOR	Waterflood
EUNICE NORTH;BLINEBRY / TUBB / DRINKARD	3284	4.2	Y
BLINEBRY;BLINEBRY	1367	4.6	
DRINKARD;DRINKARD	1000	6.0	Y
JUSTIS;BLINEBRY	708	23.6	Y
DOLLARHIDE;TUBB	628	9.6	Y
WARREN;BLINEBRY	569	2.6	Y
PADDOCK;PADDOCK	454	10.8	
TUBB;TUBB	351	14.1	
MONUMENT;TUBB	341	4.3	
LOVINGTON;PADDOCK	296	16.2	Y

Table 7. Top 2010 oil producing pools for the CBP area of the Leonard Play.
(Data source: digitized + Dwights)

poolName	2010 gas rate MCFD	2010 wells
EUNICE NORTH;BLINEBRY / TUBB /	26389	367
BLINEBRY;BLINEBRY	21629	581
TUBB;TUBB	8500	274
DRINKARD;DRINKARD	8047	280
PADDOCK;PADDOCK	5581	112
MONUMENT;TUBB	3703	111
BRUNSON SOUTH;DRINKARD	3410	105
JUSTIS;BLINEBRY	3163	174
SKAGGS;DRINKARD	2862	69
WARREN;BLINEBRY	2805	93

Table 8. Top 2010 gas producing pools for the CBP area of the Leonard Play.
(Data source: digitized + Dwights)

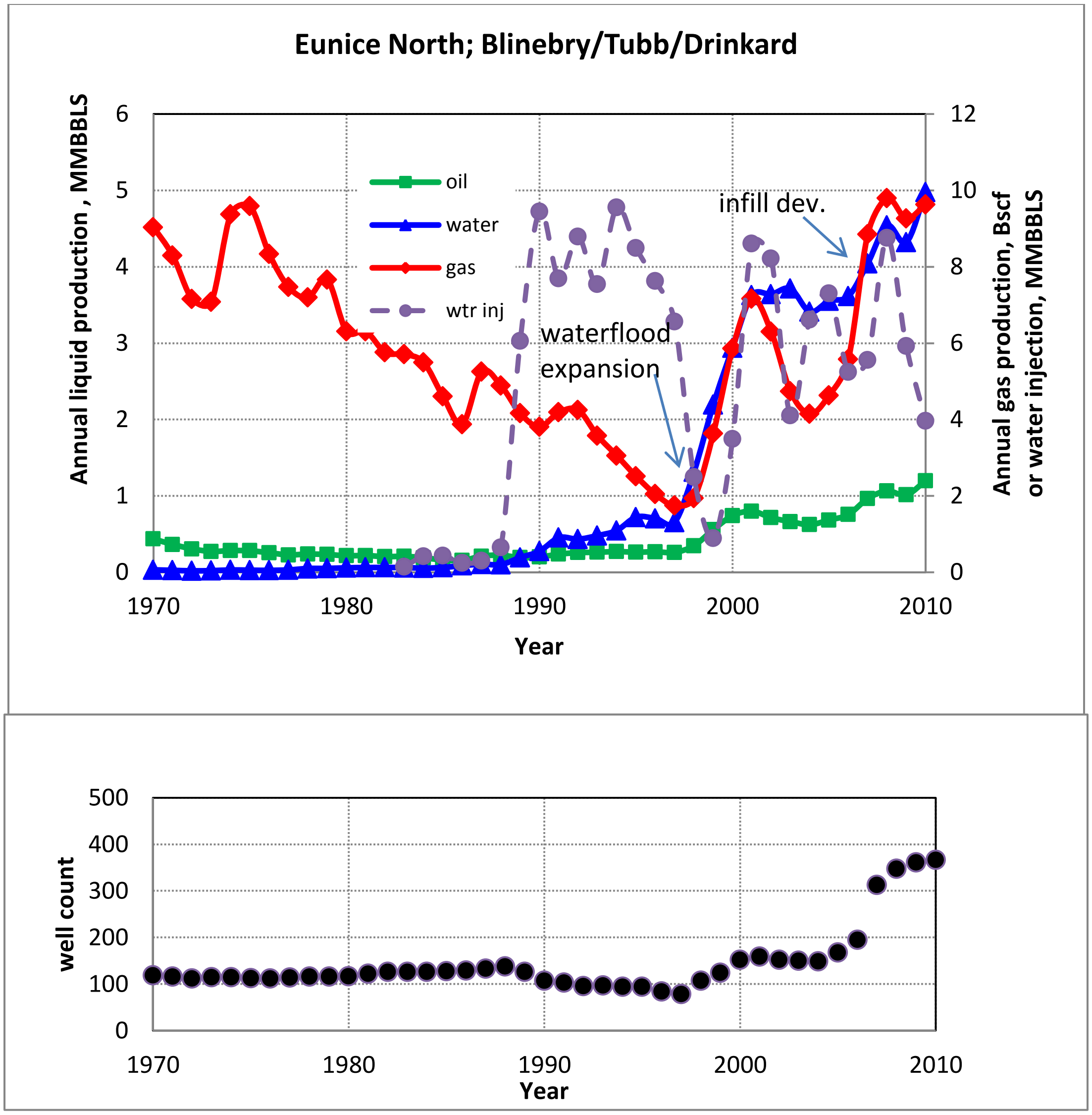


Figure 10. North Eunice (Blinebry/Tubb/Drinkard) pool performance.
(Data Source: digitized + Dwights)

Due to the high fracture intensity of many Leonard carbonate reservoirs, waterflooding has frequently resulted in premature water breakthrough in fractured zones and has left significant volumes of oil unflooded and unrecovered in the nonfractured zones. An example is the early flooding of the North Eunice pool shown in Figure 10. From the start of injection in 1983 through 1988, the volume of water injected was insufficient to develop any sweep efficiency. In 1989 the injection volume increased an order of magnitude, and remained for the following ten years; however, no oil response was observed. In 1999, a change in flooding pattern and increased density drilling finally resulted in a significant oil response.

Horizontal wells have seen limited use in the Leonard play. Figure 11 compares the number of vertical wells drilled in a given year to horizontal wells in the same year. It is evident from the graph that horizontals have a minor role; contributing only 3% to the Leonard development. The lack of horizontal wells is a consequence of the thick vertical section of stacked pay zones from the Upper Yeso through the Drinkard. A vertical well can penetrate all potential pay zones, while a horizontal well penetrates only the one selected zone. The largest concentration (25%) of horizontal wells was drilled in the West Vacuum Glorieta Unit. In this unit, horizontal laterals were drilled into porous but unfractured reservoir zones resulting in increased incremental production.

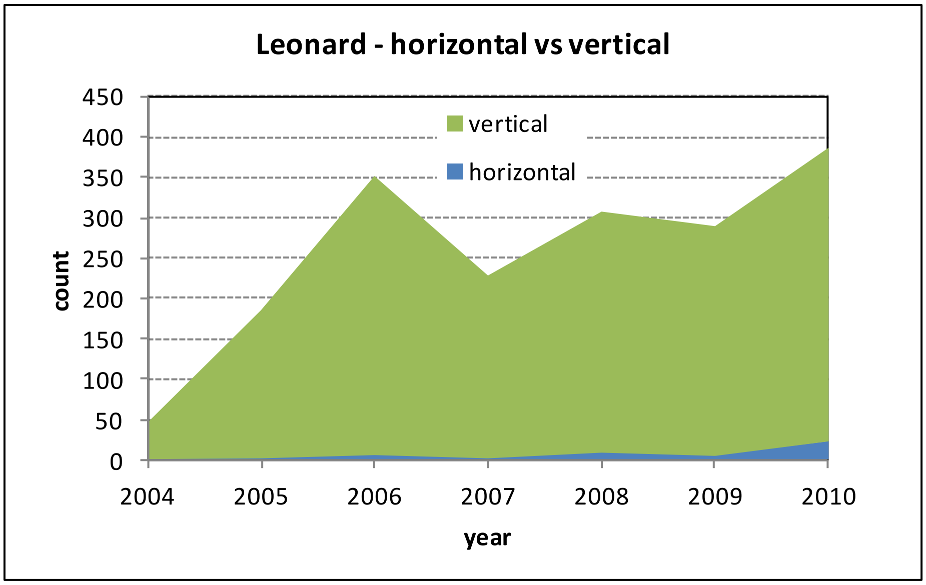


Figure 11. Comparison of horizontal and vertical well development over the last seven years for all of the Leonard Play. (Source: Gotech)

Due to the stacked multiple pay zones in this play, opportunity exists to commingle or dual complete the various subplays. Figure 12 compares completion type for the Leonard (CBP) sub play. A multiple completion indicates a well that is dual completed or commingled in two or more zones. A single completion is initially developed in one zone. In 2010 approximately 40% of Leonard wells in the CBP subplay were multiple completions. This is efficient from a reservoir development perspective while simultaneously reducing the number of wells and associated surface disturbance.

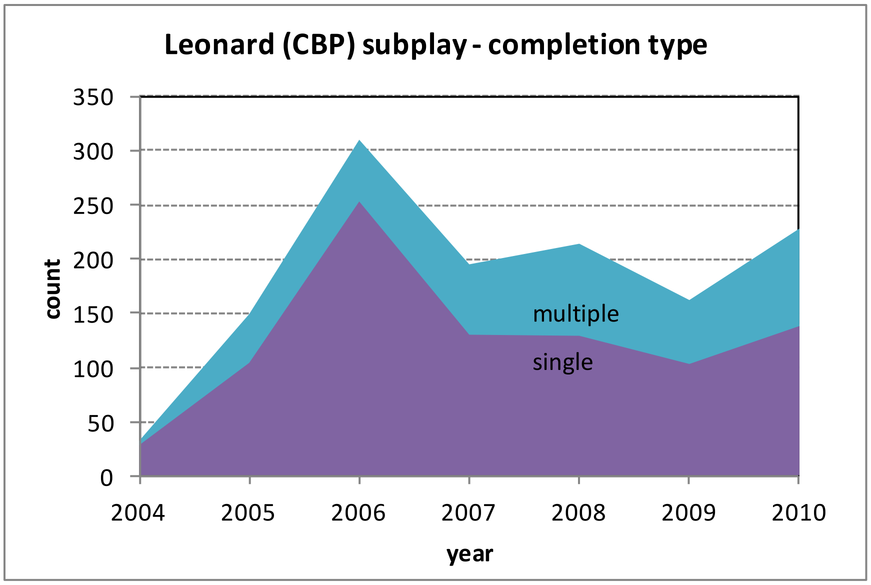


Figure 12. Comparison of single and multi-completion wells over the last seven years for the Leonard (CBP) Subplay. (Source: Gotech)

Predicted Development

Significant potential exists for this play (Figure 13). In order of priority, the potential development is:

1. **High** potential for continued Yeso (NW shelf) infill and extension drilling. Well count has been increasing by several hundred per year and growing.

2. **Moderate** potential exists for development drilling in the Central Basin Platform subplay, the majority being multiple completions.

3. Due to the thick productive zone, these formations are not a strong candidate for horizontal wells; therefore a **low** potential exists. Localized horizontal well development will occur in some areas of single thick productive zone, e.g., Vacuum Glorieta. Some pilot tests have also occurred in the Yeso, but results are not convincing evidence to promote growth.

4. **Low** potential exists for new waterflood development. Existing waterfloods have not shown good recovery performance due to heterogeneity of the reservoirs and anisotropy created by the natural fractures.

5. Blinebry, Dollarhide (Tubb-Drinkard), Drinkard, Hobbs (Blinebry), Justis (Blinebry), Lovington (Paddock), and Vacuum (Glorieta) have all been identified as amenable to CO2-EOR. However, low potential is assigned because of poor performance in waterflooding in these reservoirs, lack of CO_2 and transportation, and better targets for CO2-EOR in the San Andres.

Leonard Restricted Platform Carbonate Play

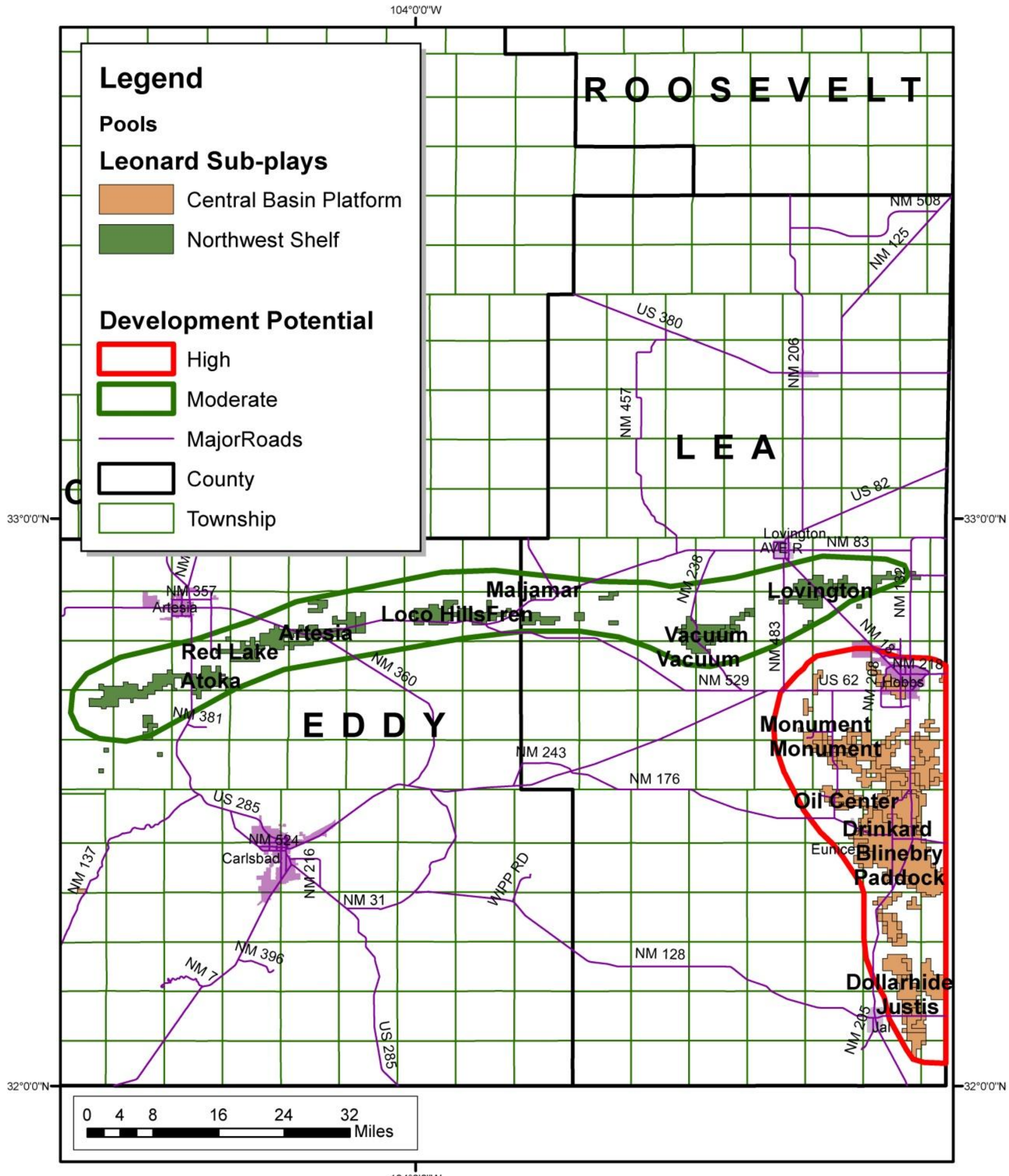


Figure 13. Potential map for the Leonard Play. Green line – high potential, red line – moderate potential

Mississippian Play

The potential for future development is ***very low***.

BRIEF SUMMARY OF GEOLOGY

An excellent discussion of Mississippian geology in Southeast New Mexico was published by Broadhead in 2009; and is recommended if additional background is desired. Depth to the top of the Mississippian ranges from 5,500 ft in the northwest to 17,000 ft in the southeast. Lower Mississippian strata are 0–800 ft thick and comprised of marine limestones and minor shales and chert. Upper Mississippian strata are 0–600 ft thick and comprised of shallow marine limestones and shales. The Barnett Shale, which is of interest as an emerging shale play, is also Mississippian age but will be discussed in a separate section.

HISTORICAL DEVELOPMENT

The first production from the Mississippian was in the Bronco pool in 1959. Since discovery, 50 pools have produced 1.5 MMBO and 39 Bscf from the Mississippian (see Figure 1). The majority of pools are small, less than several wells and 1 Bscf in cumulative gas production. Top oil and gas pools are listed in Tables 1 and 2, respectively. The largest oil pool is the Bronco (Miss), accounting for 27% of the total oil production from the play. The Austin (Mississippian) pool is the largest gas pool, accounting for 42% of the total play's gas production.

poolName	Cum_Oil MBO	percent of total	Cumulative %
BRONCO;MISSISSIPPIAN	416524	27	27
GLADIOLA;MISSISSIPPIAN	208003	13	40
EIDSON NORTHEAST;MISSISSIPPIAN	198976	13	53
AUSTIN;MISSISSIPPIAN	182774	12	65
PETERSON;MISSISSIPPIAN	159749	10	76
TOWNSEND NORTH;MISSISSIPPIAN	80631	5	81
CAPROCK NORTH;MISSISSIPPIAN	70981	5	85

Table 1. Top cumulative oil producing pools for the Mississippian play. (Data Source: Dwights+digitized)

Mississippian Play

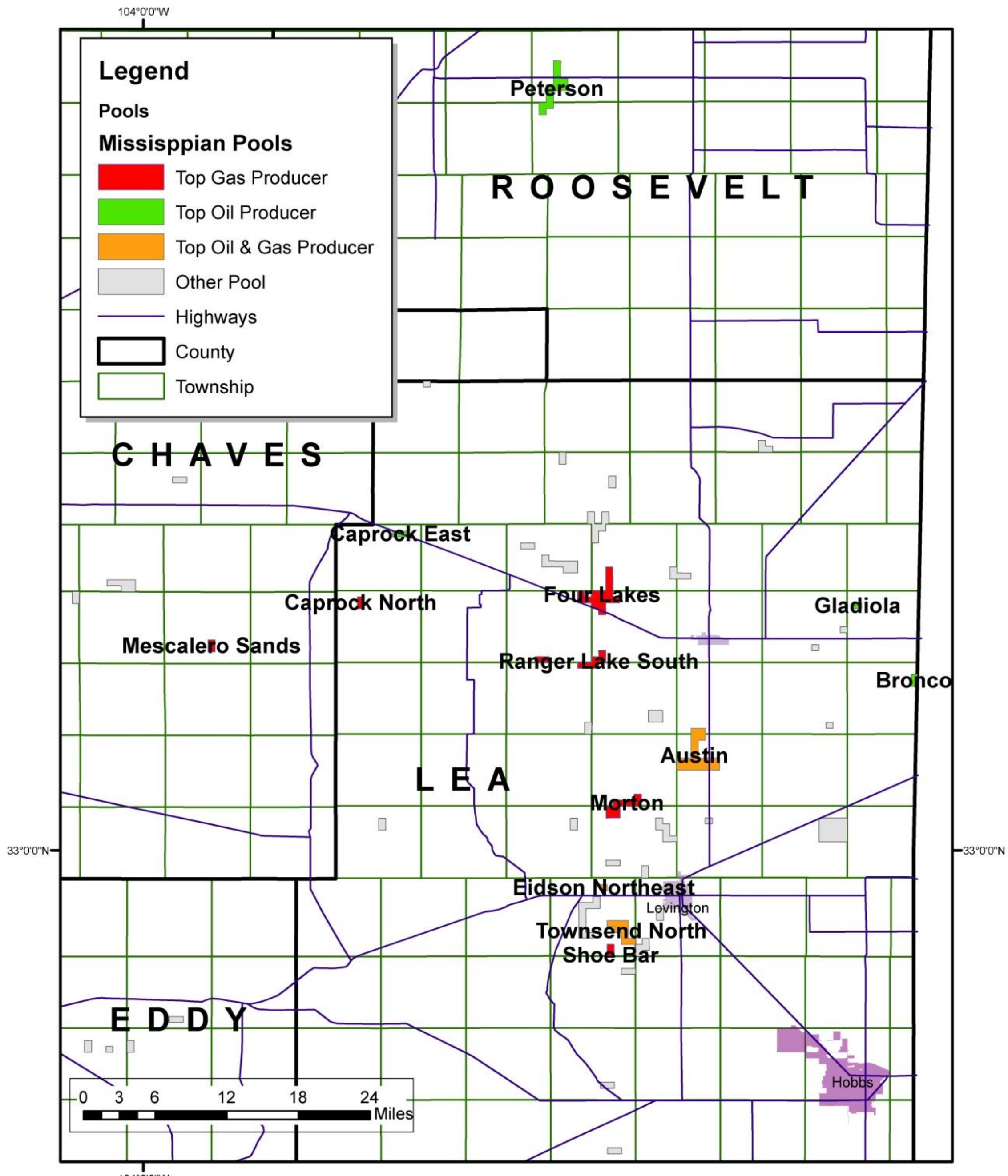


Figure 1. Pool map for the Mississippian Play

poolName	Cum_gas MSCF	percent of total	Cumulative %
AUSTIN;MISSISSIPPIAN	16417097	42.3	42.3
TOWNSEND NORTH;MISSISSIPPIAN	4079868	10.5	52.8
CAPROCK NORTH;MISSISSIPPIAN	2707325	7.0	59.7
RANGER LAKE SOUTH;MISSISSIPPIAN	2053474	5.3	65.0
EIDSON NORTHEAST;MISSISSIPPIAN	2019667	5.2	70.2
MESCALERO SANDS;MISSISSIPPIAN	1415565	3.6	73.8
MORTON;MISSISSIPPIAN	1307946	3.4	77.2
SHOE BAR;MISSISSIPPIAN	1280783	3.3	80.5
FOUR LAKES;MISSISSIPPIAN	1166470	3.0	83.5

Table 2. Top cumulative gas producing pools for the Mississippian play. (Data Source: Dwights+digitized)

Historical development of the play is shown in Figure 2. Initial production in the early 1960s is from the Bronco pool. In the 1980s, production increased in response to the development of the Austin pool. The third peak in the early 2000s is the addition of North Townsend and South Ranger Lake pools. The Austin pool production performance is shown in Figure 3.

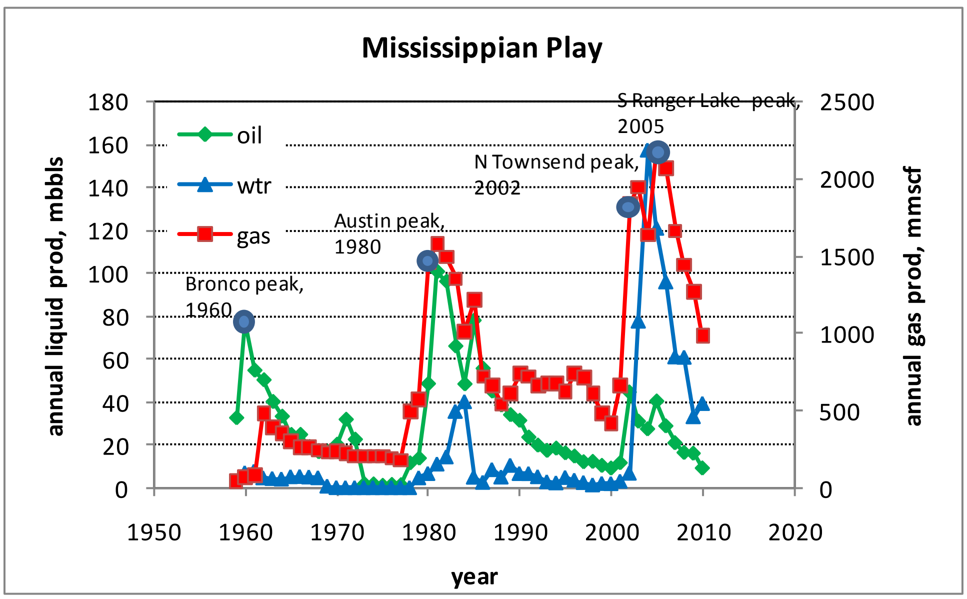


Figure 2. Annual production for the Mississippian play. (Data source: Dwights+digitized)

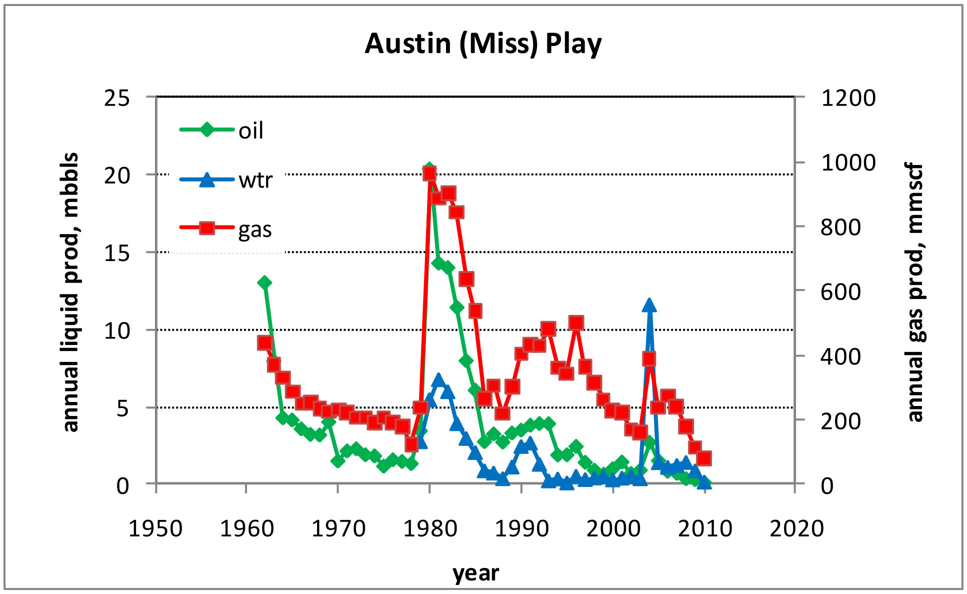


Figure 3. Annual production for the Austin (Miss) gas pool. (Data source: Dwights+ digitized)

Predicted Development

The Mississippian play is dominantly a gas play. For that reason, current low natural gas prices have significantly reduced this development (See Fig 4). Since projections for natural gas prices are too remain relatively constant, there is no economic incentive to develop these gas pools. As a result predicted completions will remain low. Furthermore, the pools are small in size and typically discovered by an uphole recompletion in an existing well. As a result the Mississippian is not a primary target for development.

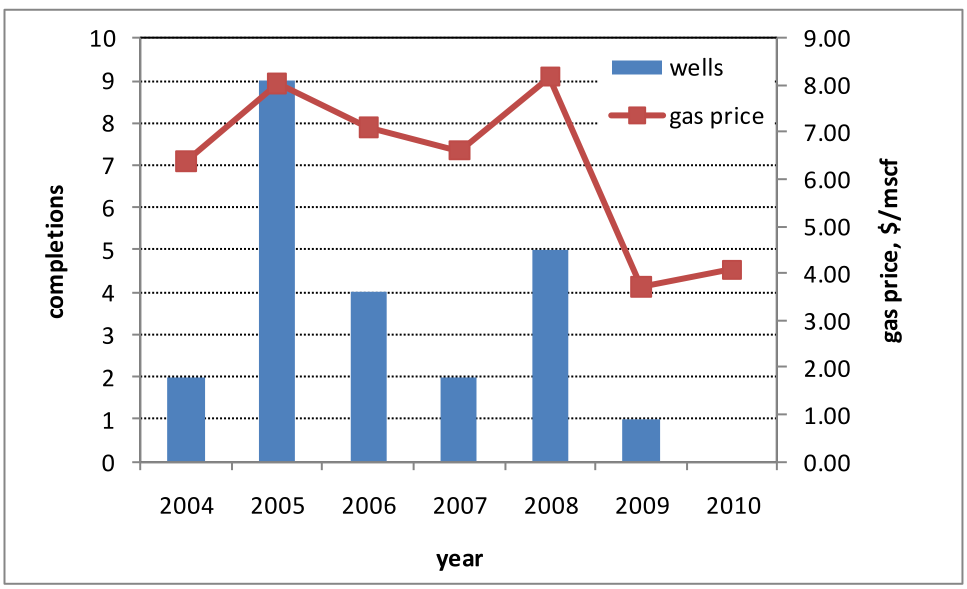


Figure 4. Mississippian well completions correlated with wellhead gas prices from 2004 to 2010. (Data Source: GOTECH and EIA)

The Mississippian pools are not conducive to secondary recovery methods and no horizontal wells have yet to be completed in this play. Future development is limited to uphole recompletions and small extensions to existing areas.

Morrow Play

The potential for future development is strongly dependent upon natural gas prices and therefore is in the ***low*** range. Based on the EIA predictions for gas prices, only a slight increase is seen in the next 25 years. Consequently, only limited gas development is forecasted.

Brief Summary of Geology

The Morrow Formation in southeast New Mexico unconformably overlies Mississippian limestones. The Morrow is subdivided into three distinct intervals commonly designated as either the lower, middle, and upper Morrow, or the "A," "B," and "C" Morrow zones (Fig 1.).The Lower and middle Morrow intervals are primarily clastic in composition and are by far the dominant Morrow producing horizons, whereas the upper Morrow is principally composed of transgressive, ooliticlimestonesinterbedded with thin shales and minor sandstones.

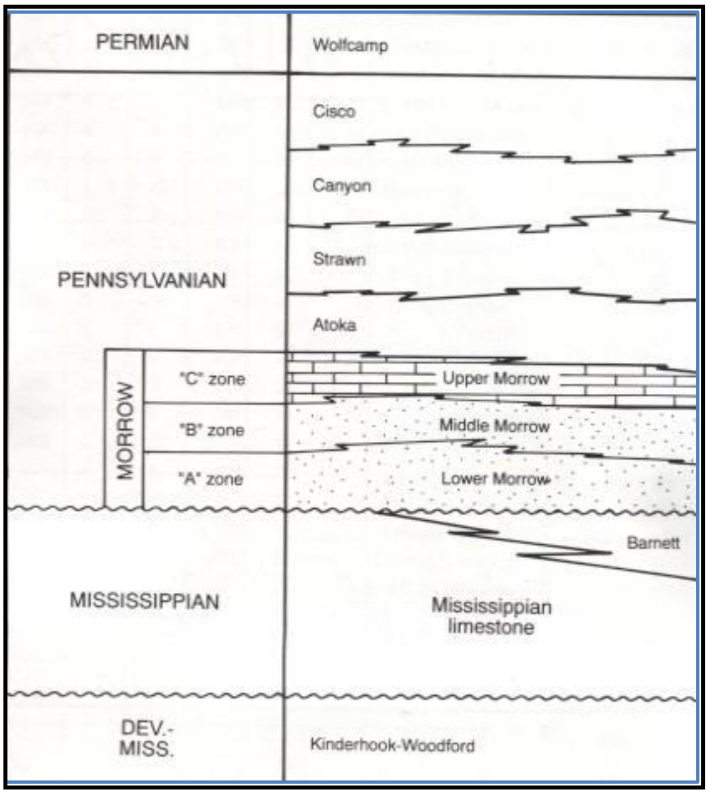


Figure 1. Stratigraphic section delineating the Morrow intervals [Speer, 1993]

The Morrow sands were deposited in a fluvial-deltaic environment as meandering channel sands. Reservoirs are stratigraphic traps.

The Pennsylvanian-age Morrow sands are primarily located in the Delaware Basin (Fig 2). Approximately 300 designated reservoirs produce gas fromthe Morrow, with one-third having produced at least 10 BCF. All reservoirs produce nonassociated gas with varying amounts of condensate.

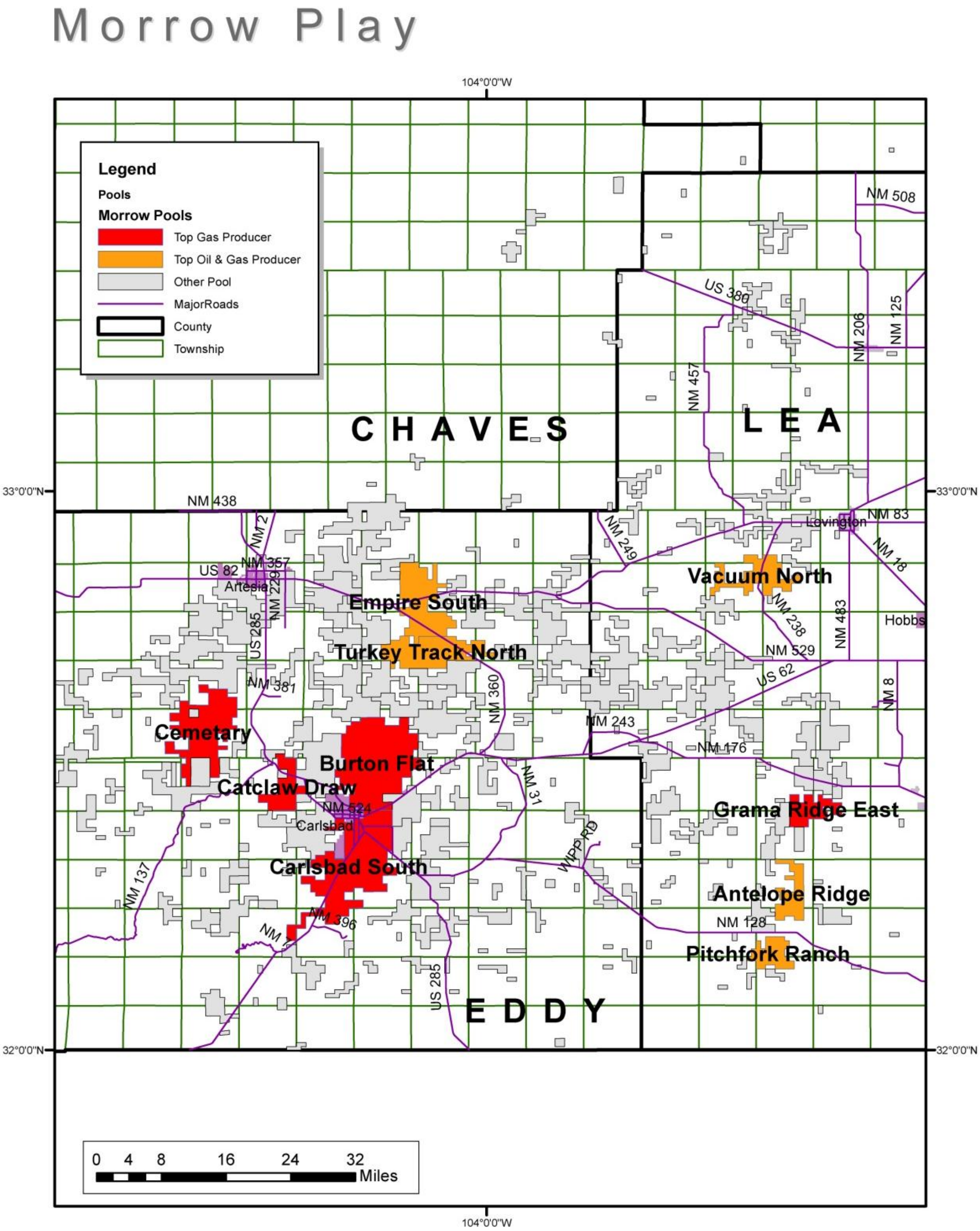


Figure 2. Location of Morrow gas reservoirs.

Reservoirs can be found at depths ranging from 9,000 ft on the west of the Delaware Basin to more than 14,000 ft in the Eastern part of the basin in Lea County. Multiple pay zones are typically encountered, resulting in a combined net pay ranging from 5 to more than 40 ft. Porosity of productive sandstones average 10%. The Morrow gas sand reservoirs in southeast New Mexico have permeability values that can range across three orders of magnitude. The best wells are completed naturally; the poorer quality rock usually needs to be fracture stimulated to produce commercially. Early attempts to fracture stimulate the Morrow with water-base systems were only marginally successful. Previous studies have suggested that the poor fracturing response to water-base systems was due to a combination of water-sensitive clays and capillary pressure effects.

Historical Development

Gas production from the Morrow sands was initially discovered in 1962 in the Quail Ridge Field. Significant development occurred in the early to mid-1970s and again in the late 1990s. In both cases development was driven by the increase in natural gas prices (See Figure 3).

The Morrow Play has been a prolific gas reservoir, producing 5.1 TCF gas with 35 MMBO. Currently, 1847 wells produced in 2010.

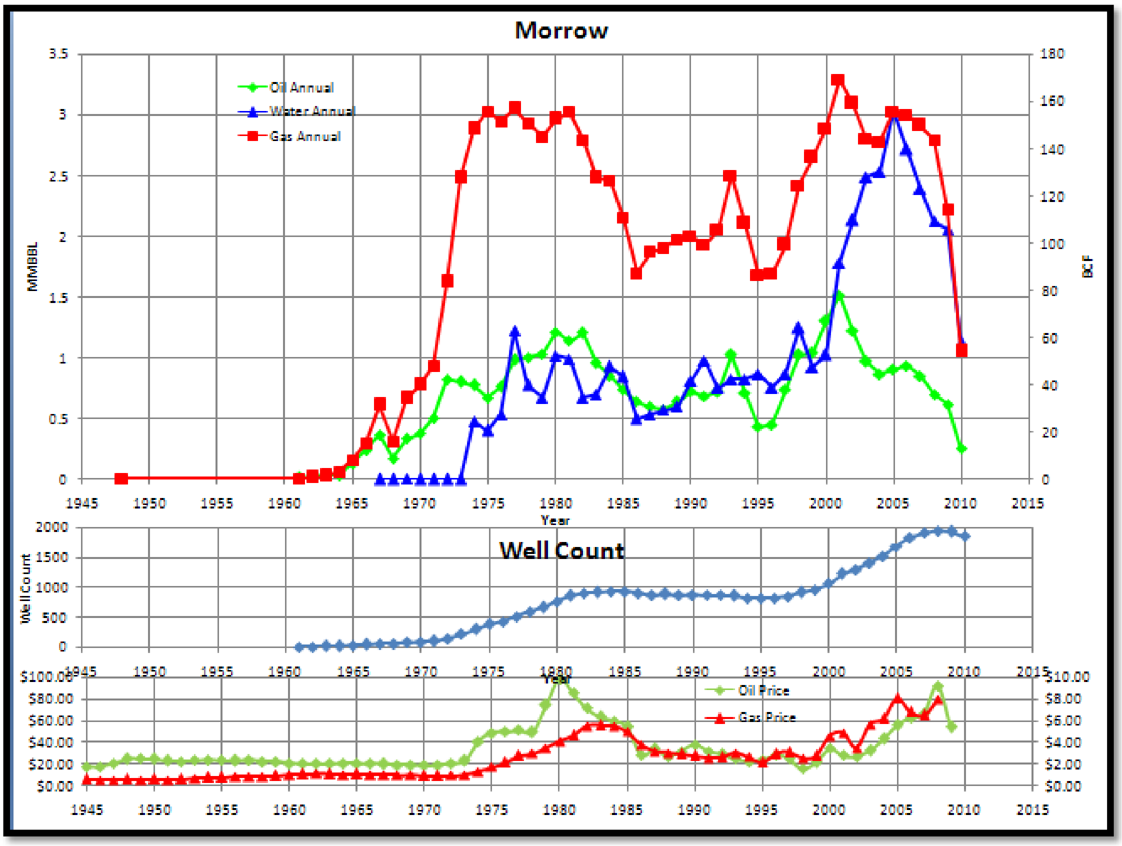


Fig. 3 Historical production and well count for theMorrow play [source: Annual Report of the New Mexico Oil & Gas Engineering Committee (prior to 1970) and Dwight's Energydata, Inc. from 1970 to present]

The top oil and gas producing pools are shown in Figure 4 and tables 1 and 2, respectively.

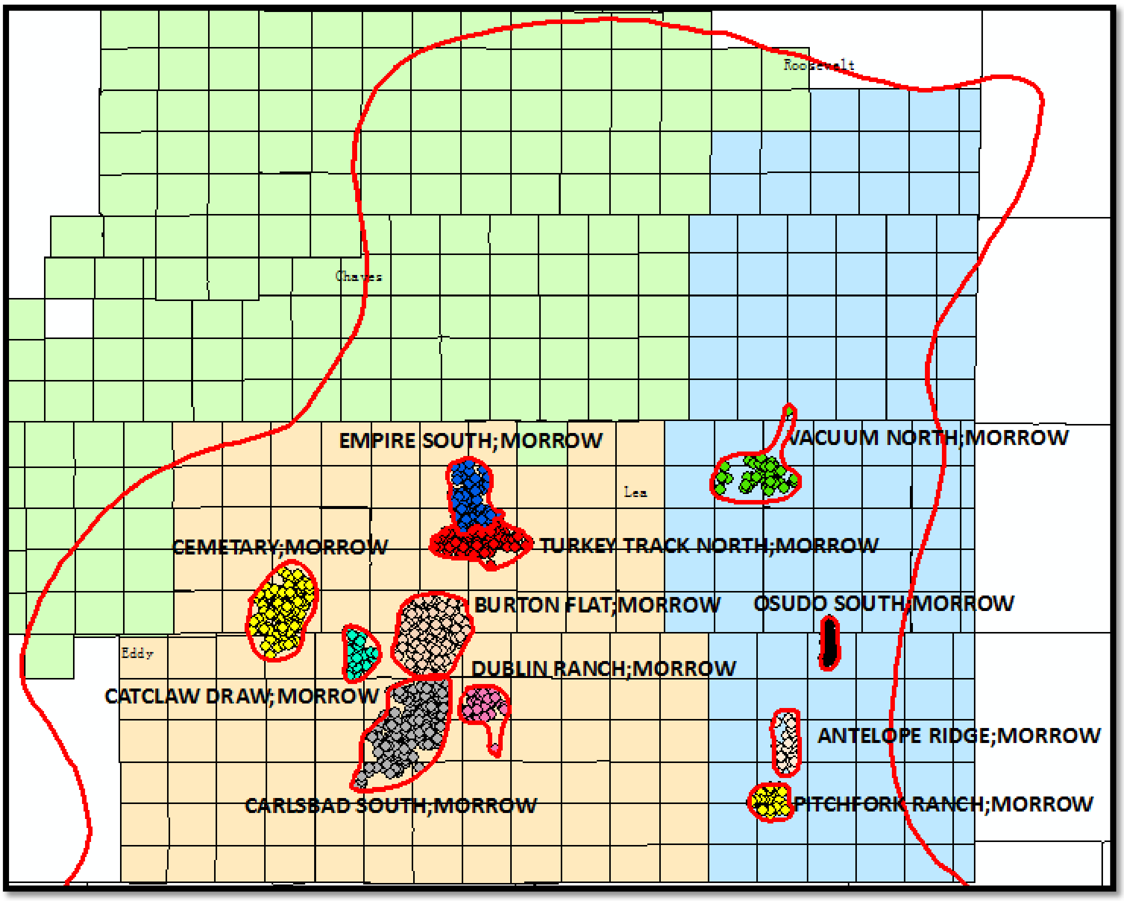


Figure 4. Top Morrow producing pools

	Pool Name	Cum_gas(BCF)	percent	Cum %
1	CARLSBAD SOUTH;MORROW	352	6.85%	6.85%
2	BURTON FLAT;MORROW	313	6.10%	12.95%
3	PITCHFORK RANCH;MORROW	261	5.08%	18.03%
4	EMPIRE SOUTH;MORROW	186	3.62%	21.65%
5	VACUUM NORTH;MORROW	165	3.21%	24.86%
6	CEMETARY;MORROW	145	2.82%	27.68%
7	CATCLAW DRAW;MORROW	136	2.64%	30.33%
8	ANTELOPE RIDGE;MORROW	117	2.28%	32.61%
9	TURKEY TRACK NORTH;MORROW	104	2.03%	34.64%
	Cumulative Gas Production	**1779**		
	Total Morrow Field	**5134**		

Table 1. Top gas producing reservoirs in the Morrow play as of August, 2010.

	Pool Name	Cum_Oil (MBE	Percent	Cum %
1	QUAIL RIDGE;MORROW	2314	6.54%	6.54%
2	EMPIRE SOUTH;MORROW	1819	5.14%	11.69%
3	VACUUM NORTH;MORROW	1711	4.84%	16.53%
4	ANTELOPE RIDGE;MORROW	933	2.64%	19.16%
5	QUAIL RIDGE NORTH;MORROW	933	2.64%	21.80%
	Cumulative Gas Production	**7710**		
	Total Morrow Field	**35369**		

Table 2. Top oil producing reservoirs in the Morrow play as August, 2010.

The top nine pools only account for approximately one-third of the total production from the Morrow. This indicates production is evenly distributed among many pools. South Carlsbad Morrow Pool is the most prolific reservoir of the Morrow play, with cumulative gas production of 352BCFG. The historical production curves for South Carlsbad are shown in Figure 5. Notice the renewed development in the early 2000s. This increase coincides with an increase in wellhead natural gas price.

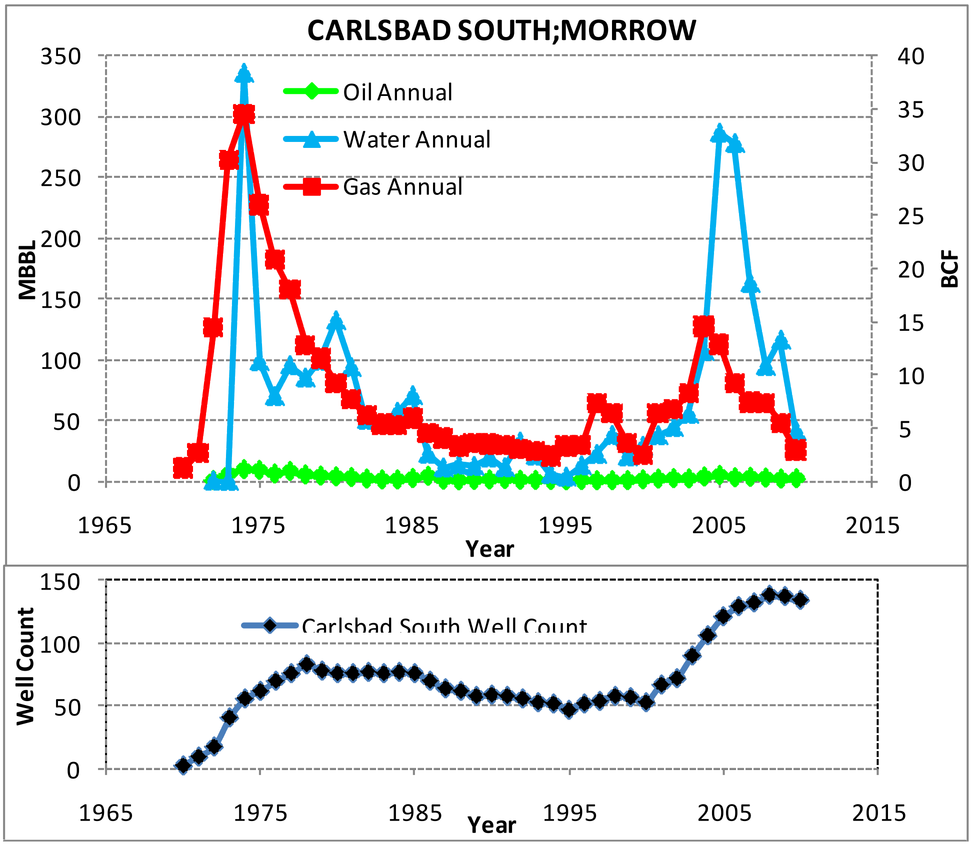


Fig. 5 Annual oil production and well count for South Carlsbad (Morrow) Pool.
(Source: digitized data and DwightsEnergydata, Inc.)

Recent activity in the Atoka, Atoka-Morrow and Morrow gas plays is shown in Figure 6. Within the past seven years, completions peaked in 2005 and have been steadily declining in response to falling natural gas prices. Approximately 1000 wells were completed in these gas plays over this seven year time period.

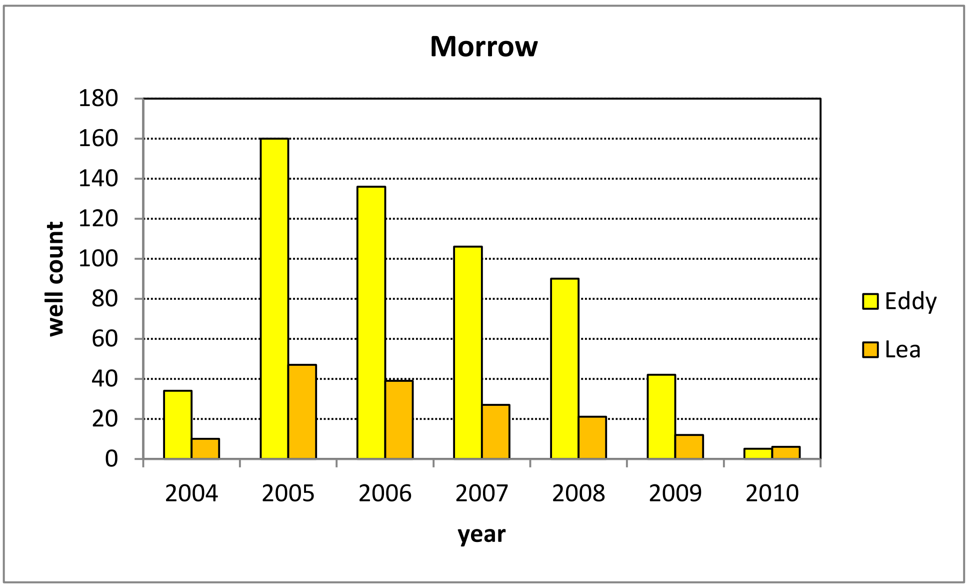


Fig 6. Recent annual completions in the Morrow play in Lea and Eddy Counties. (Data source: GOTECH)

A significant number of these completions can be attributed to renewed (infill and/or stepout drilling) development in existing fields. The south Carlsbad Pool (Fig 5) is one example. A second example is the Turkey Track (Morrow) Pool shown in Figure 7. Within a 5 year time span (1995 to 2000) annual gas production increased 503% (1.2 to 7 Bcf) and simultaneously the well count increased 111% (18 to 38). The map in Figure 7 shows the location of the additional development was primarily on the southern part of the pool.

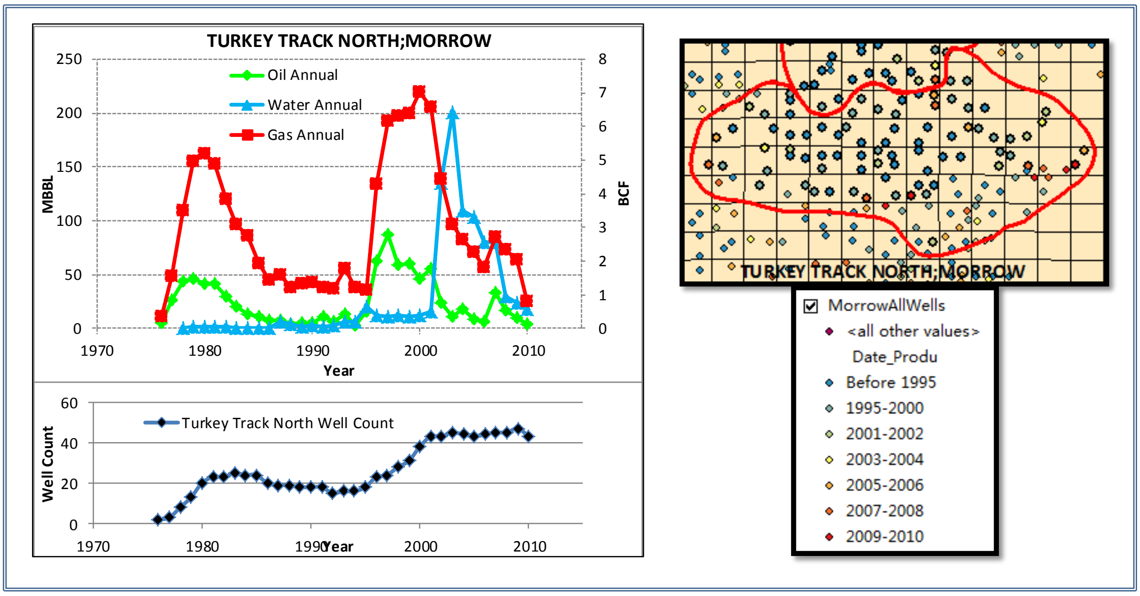


Fig 7.Annual production and well count for Turkey Track (Morrow) Pool and location map of wells coded to the date of first production. (Data Source: Dwights Energydata, Inc.)

A review of the top nine pools showed a similar trend in development for seven of the nine pools. Table 3 lists the increase in gas production and well count observed.

Pool name	Increase in annual gas prod Bcf	Increase in annual gas prod %	Increase in well count	Increase in well count %
CARLSBAD SOUTH;MORROW	12.1	484%	53	100%
BURTON FLAT;MORROW	7.4	224%	38	69%
PITCHFORK RANCH;MORROW	none observed			
EMPIRE SOUTH;MORROW	2.2	73%	17	68%
VACUUM NORTH;MORROW	1.6	66%	9	60%
CEMETARY;MORROW	4.9	368%	42	124%
CATCLAW DRAW;MORROW	none observed			
ANTELOPE RIDGE;MORROW	2.8	809%	1	7%
TURKEY TRACK NORTH;MORROW	5.8	503%	20	111%

Table 3. Increase in annual gas production and well count due to additional development in the top nine Morrow pools.

Only five horizontal wells have been drilled in the Morrow, the first in 2000 (Fig. 8). A comparison of the cumulative production of the horizontal wells in the Morrow to conventional vertical wells is shown in figure 9.

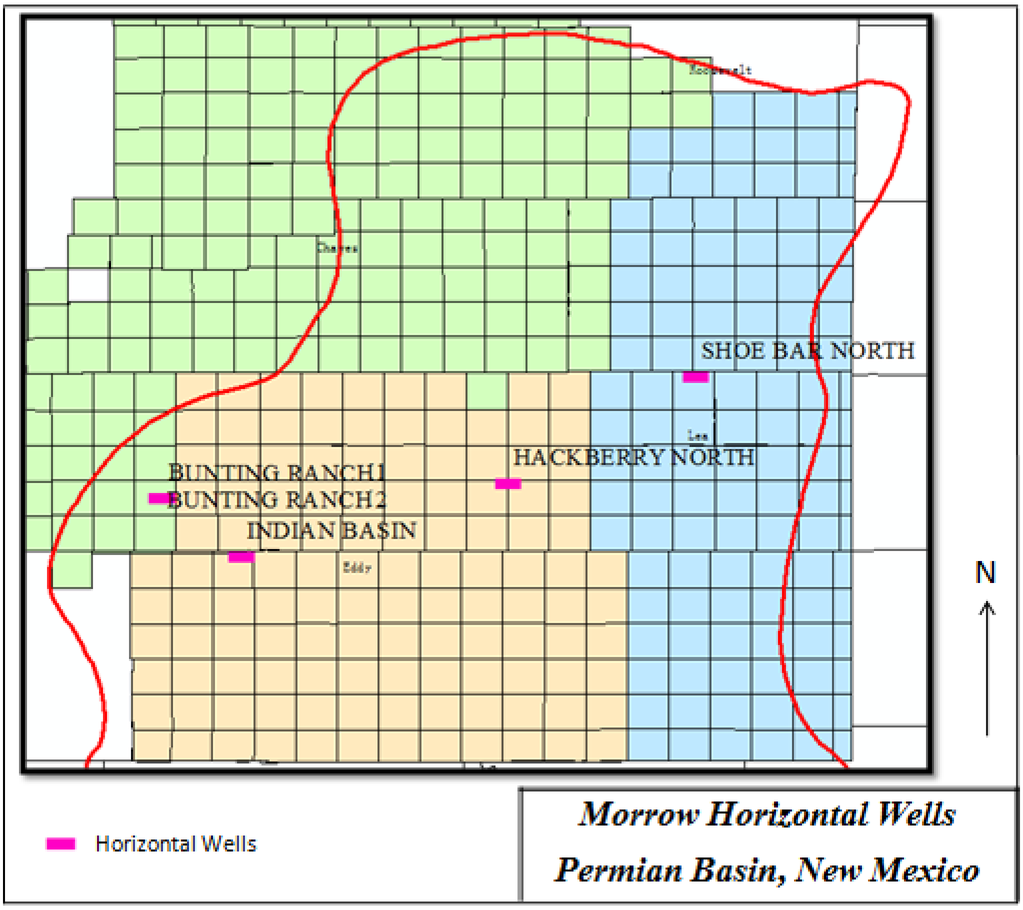


Fig. 8 Location of Horizontal wells in the Morrow play

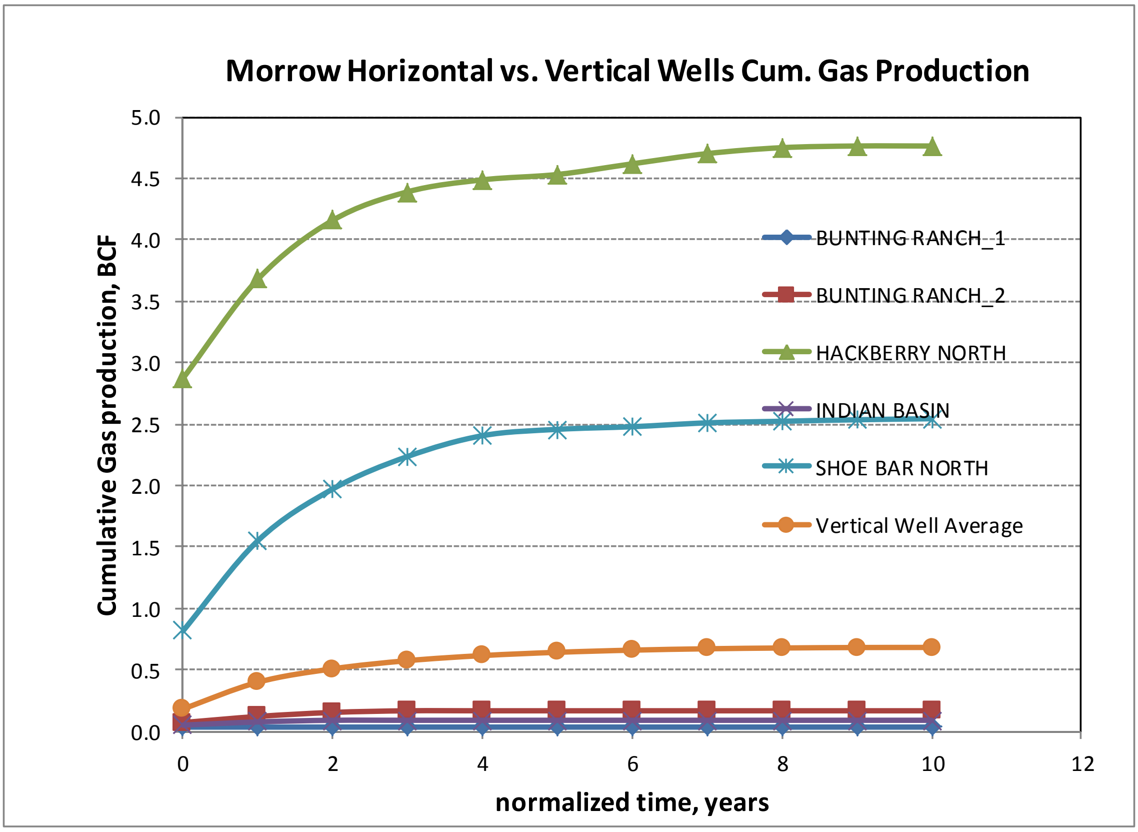


Fig. 9 Cumulative Production of individual horizontal wells to the average vertical well in the Morrow Play

The time scale for all wells in fig 9 has been shifted such that first production begins at time zero. In this way we are comparing first year production for all wells and so on. The vertical well curve is the average of 1513 vertical wells completed in the Morrow since 2000, the year of the first horizontal well. Observe two of the five horizontal wells (40%) did better than the vertical well average, while the remaining three out of five did not. Unfortunately the sample set is small and therefore statistics are not representative.

Predicted Development

Additional infill/stepout locations are available in a number of the Morrow Pools. As an example, in the Turkey Track pool (Fig 7) approximately 90 160-acre locations are within the pool boundary outlined in red on the figure. Other pools have similar opportunities; however, the current low natural gas prices have significantly reduced this development (See Fig 6). Since projections for natural gas prices are to remain relatively constant, there is no economic incentive to develop these gas pools. As a result predicted Morrow potential will remain low, with any activity expected to be confined to the currently top producing pools listed in Tables 1 and 3.

Too few horizontal wells have tested the Morrow and those that have, the results are mixed. Due to the depth, complex reservoir and natural gas prices, horizontal wells are not predicted to be significant.

Northwest Shelf Upper Pennsylvanian Carbonate Play

BRIEF SUMMARY OF GEOLOGY

Reservoirs of the Northwest Shelf Upper Pennsylvanian Carbonate trend extends from the shelf edge near Carlsbad in Eddy County onto the shelf interior in Roosevelt and Chaves Counties (Fig. 1).

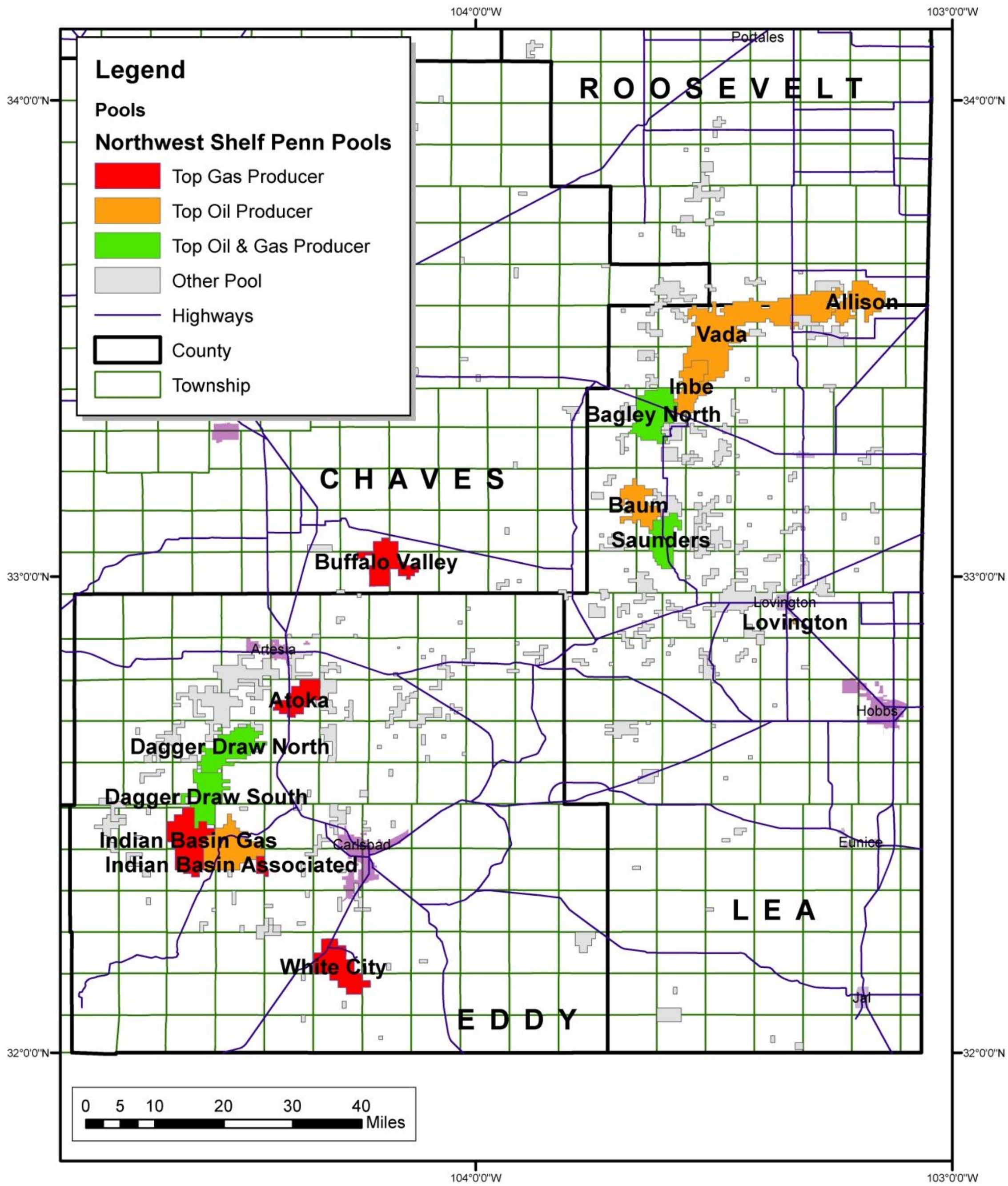


Figure 1. Pool map for Northwest Shelf Upper Pennsylvanian Carbonate Play

Reservoirs included in this play are carbonates of the Upper Penn Canyon, Cisco and Bough D zones and the Lower Wolfcampian Bough B and C (Figure 2). The boundary between reservoirs included in this play and the Wolfcamp play is not well-established and at times somewhat arbitrary; however available data indicate that the reservoirs assigned to the Wolfcamp Platform carbonate play are younger than those assigned to this play.

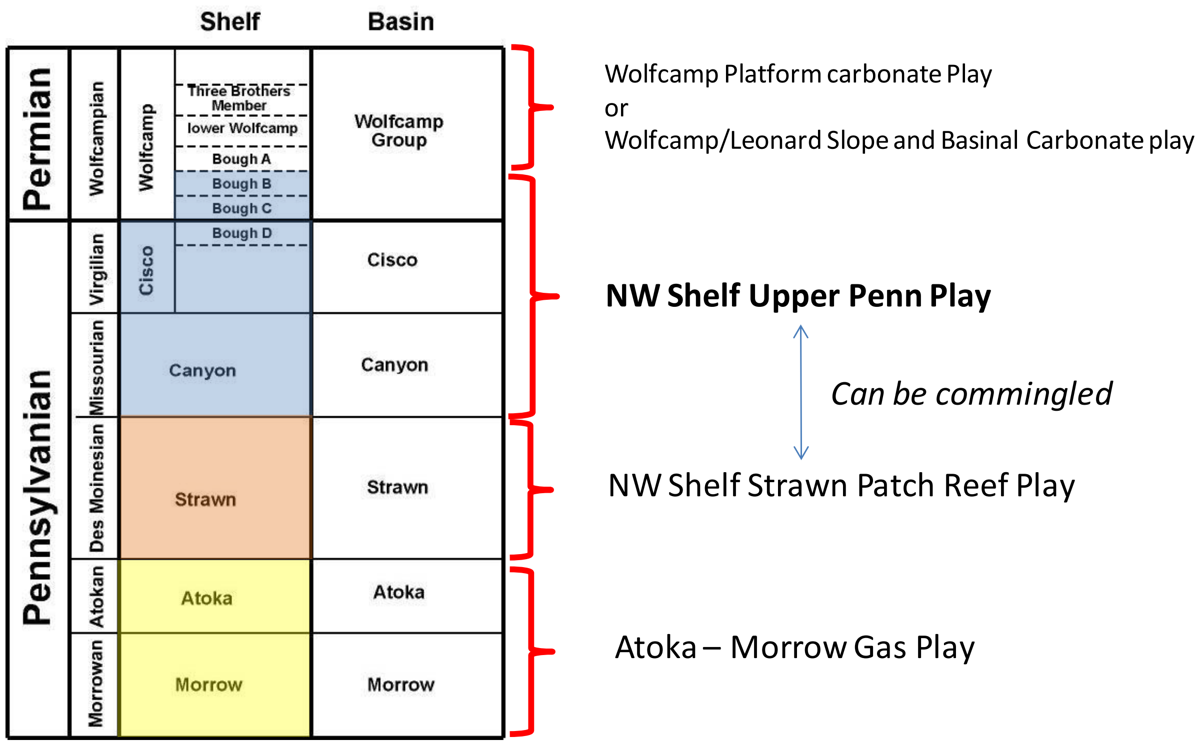


Figure 2. Stratigraphic units that comprise the NW Shelf Upper Penn Play

Broadhead (1999) provides an excellent summary of the Upper Penn and Lower Wolfcamp geology and potential for finding underdeveloped oil reservoirs.

Initial exploration considered trapping in the Upper Penn as structurally controlled; subsequently initial development of Upper Pennsylvanian carbonate reservoirs was generally concentrated on the crests of the anticlines. Later development off structure resulted in increased production. The stratigraphic nature of entrapment was often not recognized until large portions of the reservoir were drilled out many years after initial discovery. Traps in the Northwest Shelf Upper Pennsylvanian carbonate play are primarily stratigraphic.

Reservoirs on the Northwest Shelf are limestones; progressively becoming more dolomitized towards the southwest (Dagger Draw area). Productive porosity is mostly intercrystalline, intergranular, and vugular; the porosity system is dominated by vugular porosity. Depth to production varies from 7400 ft to 11,500 ft.

Historical Development

First production from this play was in 1949 from the Bagley and Crossroads pools. Since then, over 240 pools have reported cumulative production of 424 MMBO, 4.6 Tscf, and 1,763MMBW for this play. Figure 3 shows the performance and activity of this play since inception, with several of the more prolific pools highlighted.

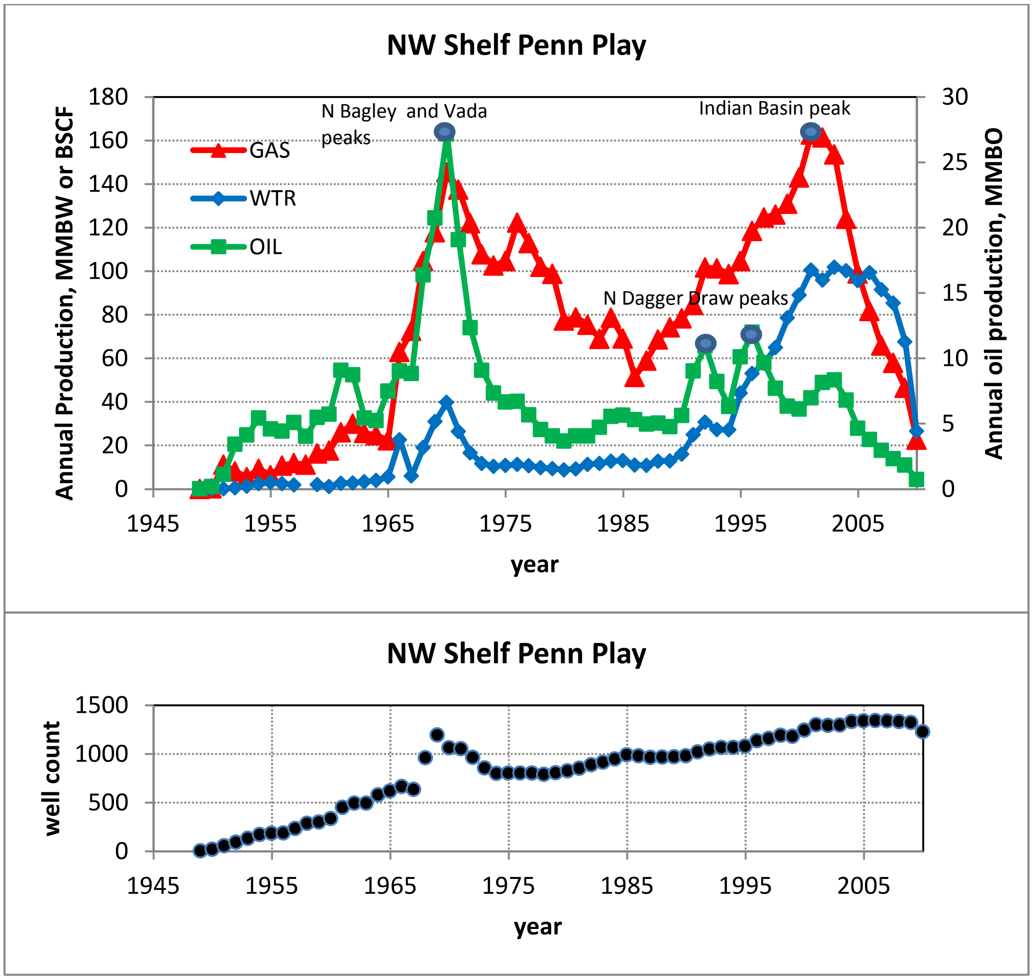


Figure 3. Annual production and well count for the Northwest Shelf Upper Penn Play. (Source: digitized+dwights)

The top oil pools by cumulative production are listed in Table 1. These ten pools represent 75% of the play's total oil production, thus dominating the play's production. Peak production for these pools occurred in 1970 at ~74,000 bopd, when both North Bagley and Vada pools were initially developed.

poolName	Cum_Oil* MMBO	percent of total	Cumulative %
DAGGER DRAW;UPPER PENN, NORTH	53.0	12%	12%
VADA;UPPER PENN	50.8	12%	24%
INDIAN BASIN;UPPER PENN	43.3	10%	35%
BAGLEY;PERMO PENN, NORTH	42.4	10%	45%
SAUNDERS;PERMO UPPER PENN	39.5	9%	54%
ALLISON;UPPER PENN	22.3	5%	59%
LOVINGTON;UPPER PENN, NORTHEAST	18.3	4%	64%
DAGGER DRAW;UP PENN, SOUTH (ASSOC)	17.5	4%	68%
BAUM;UPPER PENN	14.5	3%	71%
INBE;PENNSYLVANIAN / PERMIAN	14.4	3%	75%

Table 1. Top pools by cumulative oil production through July 2010*.
(Source: digitized+dwights)

Current (2010) top oil producing pools are shown in Table 2. Pools highlighted in blue in the table are not listed in Table 1 as a top cumulative pool.

poolName	2010* oil prod BOPD	horiz wells
INDIAN BASIN;UPPER PENN	1059	4
LOVINGTON;UPPER PENN, NORTHEAST	319	1
BAGLEY;PERMO PENN, NORTH	217	
DAGGER DRAW;UPPER PENN, NORTH	185	3
MESCALERO;UPPER PENN, NORTH	130	
SAUNDERS;PERMO UPPER PENN	125	
VACUUM;UPPER PENN	94	
CAUDILL;PERMO UPPER PENN	69	1
TEAS;PENN (GAS)	68	
TOBAC;UPPER PENN	64	

Table 2. Top pools by average oil production rate for 2010 (Through July 2010*).
(Source: digitized+dwights)

The most prolific oil pool is the North Dagger Draw (Upper Penn) in Eddy County. Remarkably, peak production did not occur until 1996, *over thirty years after initial discovery*. Figure 4 illustrates the pool performance and location map for this pool. Notice significant water is also produced, indicating the active water drive system and thus requiring submersible lift equipment.

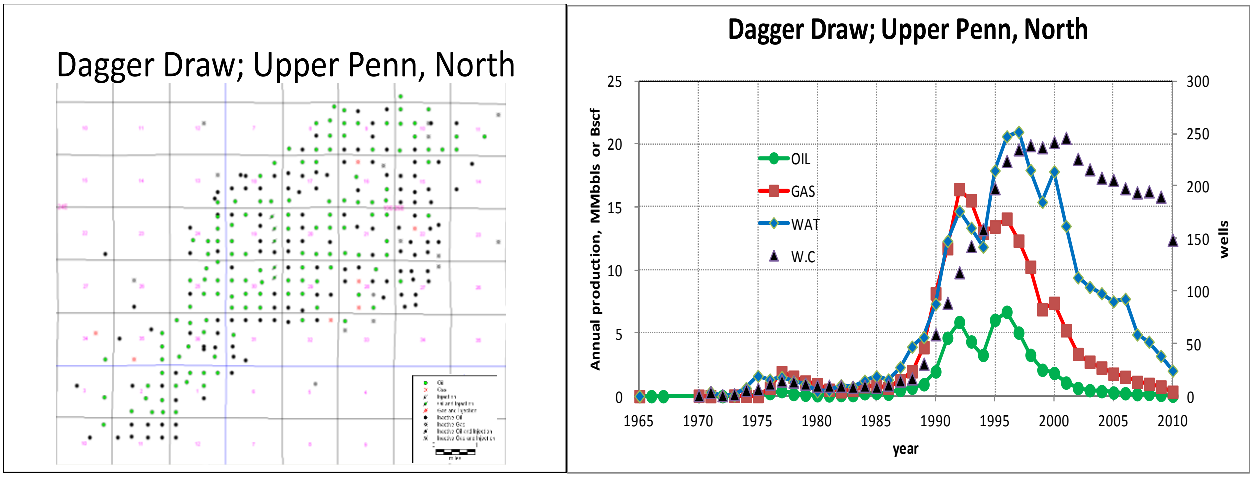


Figure 4. Location map and performance curves for North Dagger Draw (Upper Penn) pool. (Data Source: digitized+Dwights)

The second most prolific pool was the Vada (Penn) Field discovered in 1967 and reaching peak production three years later. Figure 5 illustrates the location map and performance curves for this pool. Notice only initial development occurred for this pool followed by a subsequent decline in production and well count.

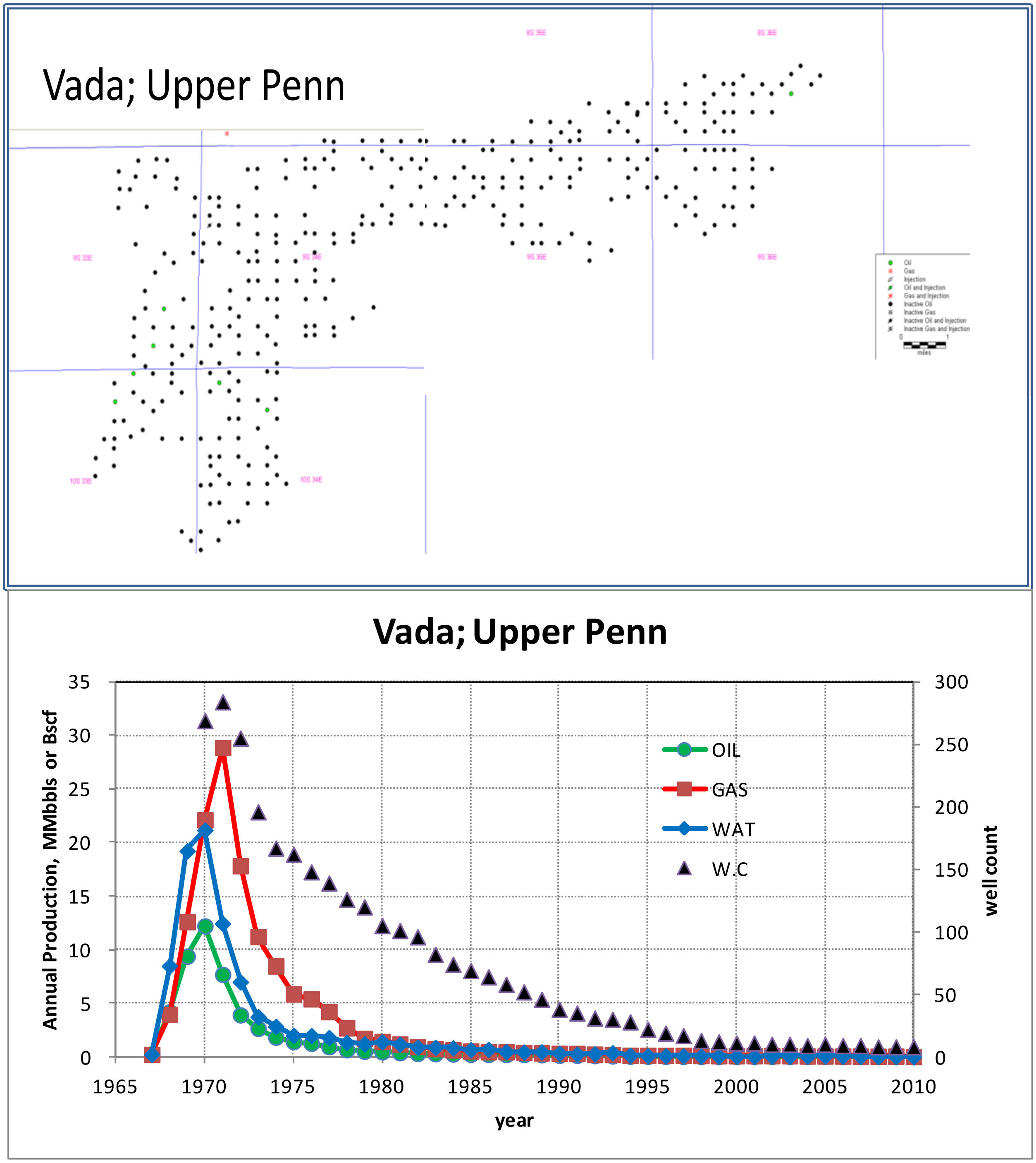


Figure 5. Location map and performance curves for Vada (Upper Penn) pool. (Data Source: digitized+Dwights)

The top gas field is the Indian Basin (Upper Penn) pool; contributing over 50% of the total gas production from this play or approximately 2.4 Tcf (see Table 3).

poolName	Cum_Gas* BCF	percent of total	Cumulative %
INDIAN BASIN;UPPER PENN (PRO GAS)	2392	52%	52%
DAGGER DRAW;UP PENN, SOUTH (ASSOC)	263	6%	57%
WHITE CITY;PENN (GAS)	217	5%	62%
DAGGER DRAW;UPPER PENN, NORTH	167	4%	66%
ATOKA;PENN	165	4%	69%
BAGLEY;PERMO PENN, NORTH	154	3%	72%
BUFFALO VALLEY;PENN (PRORATED GAS)	153	3%	76%
SAUNDERS;PERMO UPPER PENN	85	2%	78%
EMPIRE; PENN (GAS)	60	1%	79%
MCKITTRICK HILLS;UPPER PENN (GAS)	59	1%	80%

Table 3. Top pools by cumulative gas production through July 2010*.
(Source: digitized+dwights)

The location map and performance curves are shown in Figure 6. Even though discovered in 1965, peak production didn't occur until 2002 at over 300MMscfd. Currently this pool produces over 19 MMscfd, making it the most productive pool for 2010 (see Table 4).

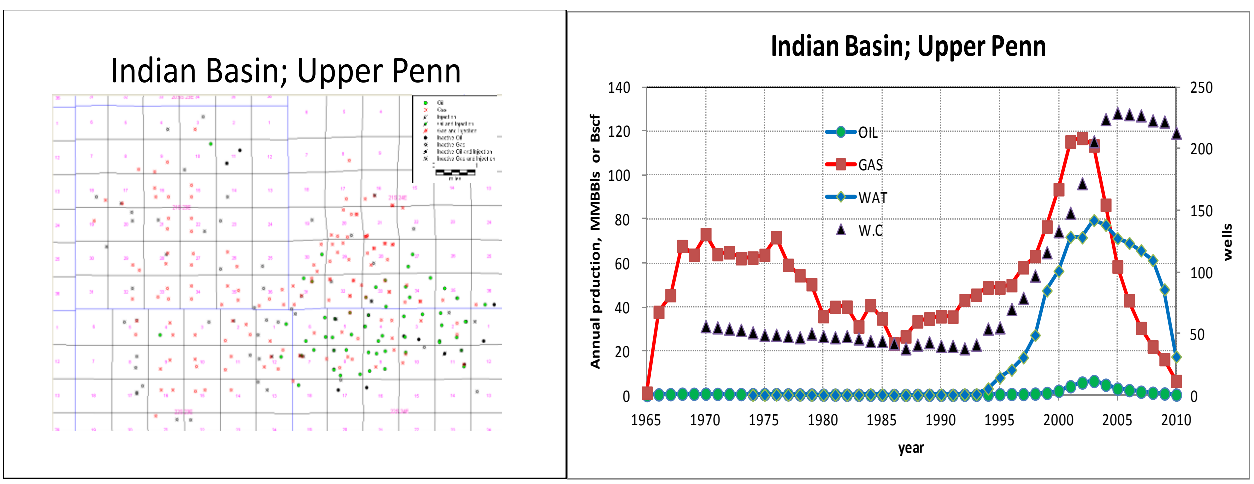


Figure 6. Location map and performance curves for Indian Basin (Upper Penn) pool. (Data Source: digitized+Dwights)

poolName	2010 gas prod MSCFD	horiz wells
INDIAN BASIN;UPPER PENN (ASSOC)	19547	4
MCKITTRICK HILLS;UPPER PENN (GAS)	12330	
INDIAN BASIN;UPPER PENN (PRO GAS)	11737	
WHITE CITY;PENN (GAS)	8949	
DAGGER DRAW;UP PENN, SOUTH (ASSOC)	3720	8
BUFFALO VALLEY;PENN (PRORATED GAS)	2945	
PENASCO DRAW;PERMO PENN (GAS)	2788	
LEA;PENN (GAS)	2378	
BAGLEY;PERMO PENN, NORTH	2323	
EMPIRE; PENN (GAS)	2319	

Table 4. Top pools by average gas production rate for 2010 (Through July 2010*). (Source: digitized+dwights)

Development in the last seven years has been limited to infill drilling in the large pools and random one or two well wildcat tests in a variety of locations. New wells peaked in 2005 (See figure 7) and has been steadily declining since. Due to the significant gas production from this play, the declining trend mirrors the decline in gas price. As a result, the forecasted low gas prices will limit the future development in this play.

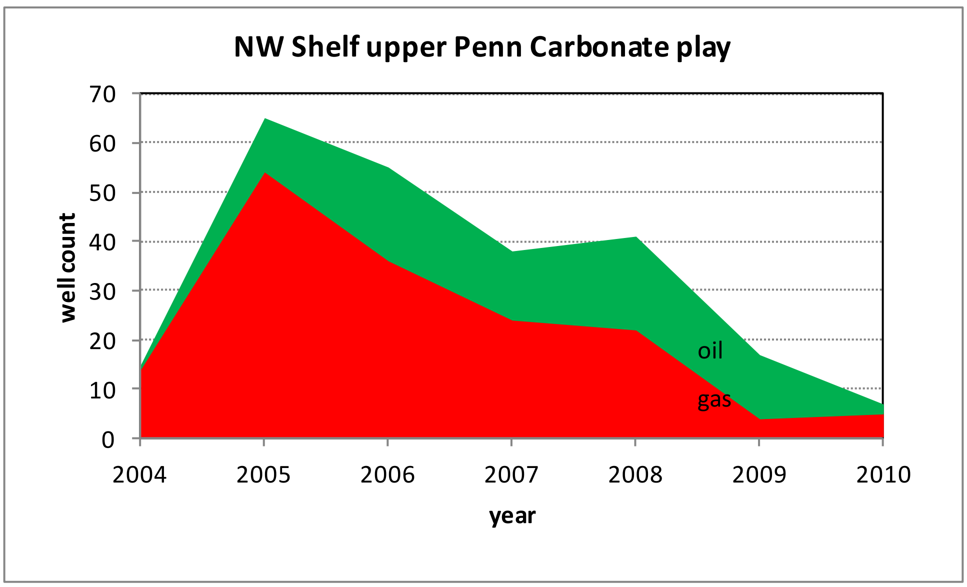


Figure 7. Recent new well activity for the Northwest Shelf (Uppen Penn) Carbonate play. Both gas and oil wells are shown. (Data source: GOTECH).

The Upper Penn play has not been a prime target for horizontal well development; primarily because of the rather thick vertical section of pay zone available, not conducive to horizontal drilling. Limited horizontal wells have been drilled (See Tables 2 and 4), but have not provided significant production increases.

Water injection in these pools is primarily for disposal purposes of the significant produced water volumes. Subsequently no genuine waterflood pattern has yet to be developed. Also the active water drive in the majority of these reservoirs eliminates the need for waterflooding.

FUTURE DEVELOPMENT

No major future development is expected for this play. Recent activity has shown that horizontal well development and waterflood potential are limited. Furthermore, the low to stable predicted gas prices will suppress gas play development such as the Upper Penn.

Several of these pools (Allison , North Bagley, Inbe, Saunders, and Vada) have been screened as amenable to EOR – CO_2 (ARI Report, 2006). From a technical viewpoint, bypassed oil in these reservoirs can be contacted by the CO_2 resulting in increase in production. This has been demonstrated in several Penn (Mostly Canyon Reef) pools in West Texas. From a feasibility viewpoint, the lack of availability of CO_2, the cost to implement and the availability of other more promising EOR-CO_2 areas, are all significant obstacles to overcome.

Northwest Shelf Strawn Patch Reef Play

The potential for future development is ***low***.

BRIEF SUMMARY OF GEOLOGY

Reservoirs of the Northwest Shelf Strawn Patch Reef play lie on the Northwest Shelf and in the Delaware Basin (Figure 1). Pools in Lea County are predominantly oil productive; while pools in Eddy County are mostly gas productive. Reservoirs are patch reefs of Strawn age; built on localized pre-existing structures at the time of deposition. Seals are interbedded marine mudstones.

Porosity in the productive unit is intercrystalline and vuggy and the limestone is extremely fractured. Reservoirs are internally complex and very heterogeneous and anisotropic.

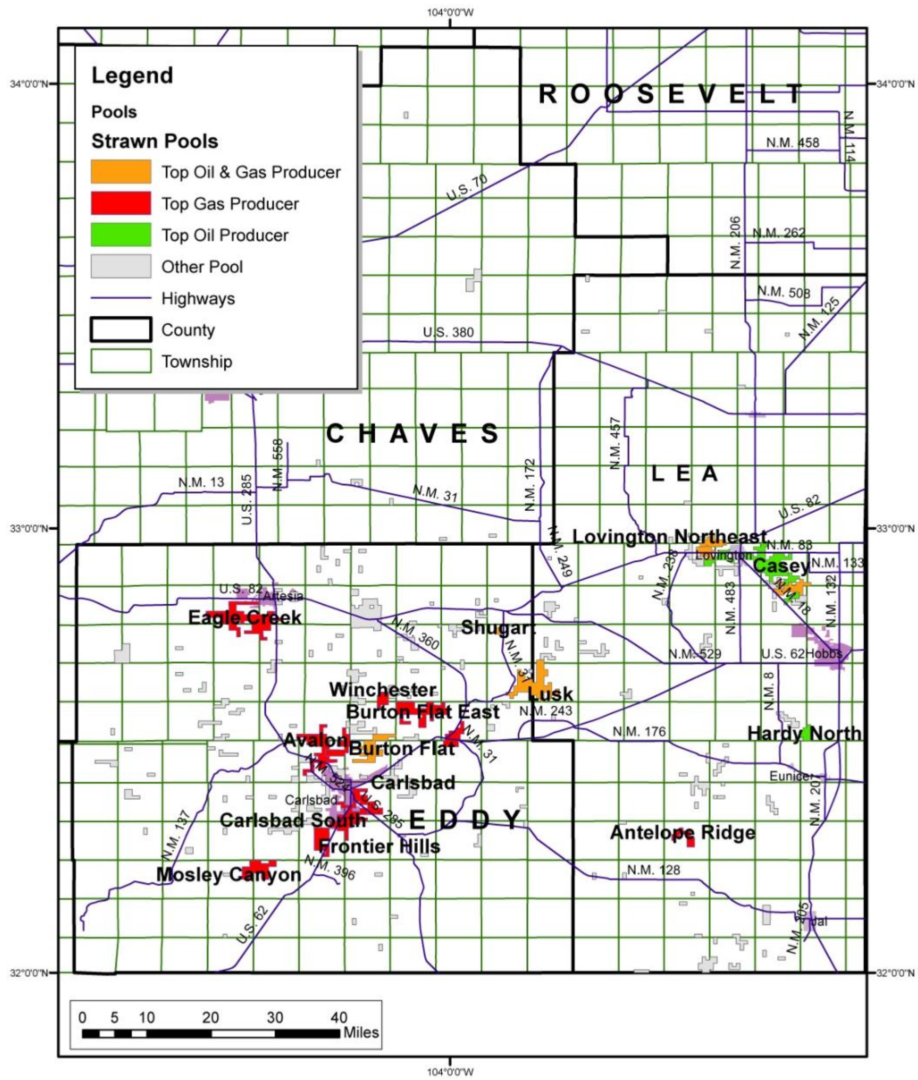


Figure 1. Pool map for the Northwest Shelf Strawn Patch Reef Play

HISTORICAL DEVELOPMENT

Approximately 200 pools have produced 103 MMBO, 703 Bcf gas, and 89.5 MMBW from this play since 1946 (Figure 2). Development has been consistent since the early 1970s, with well count continuously increasing over the time period. Gas has been the dominant target and demonstrates a cyclic pattern of production as a result of the gas price.

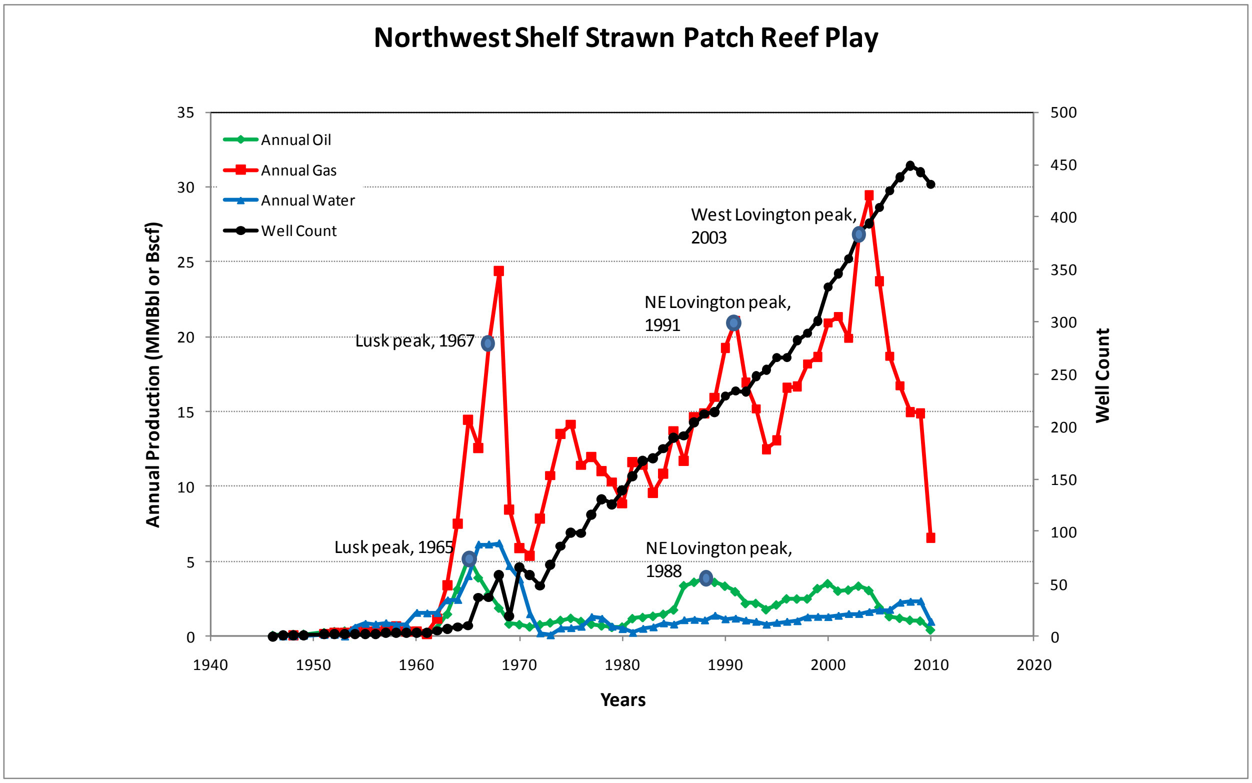


Figure 2. Annual production and well count for the Northwest Shelf Strawn Patch reef play. (Source: digitized+dwights)

The top cumulative oil producing plays is shown in Table 1. The top two pools, the Lusk and

poolName	Cum_Oil MMBO	percent of total	Cumulative %
LOVINGTON NORTHEAST;PENN	20.0	19%	19%
LUSK;STRAWN	19.6	19%	39%
SHIPP;STRAWN	9.2	9%	48%
LOVINGTON WEST;STRAWN	9.0	9%	56%
CASEY;STRAWN	3.5	3%	60%
BURTON FLAT EAST;STRAWN	3.3	3%	63%
HARDY NORTH;STRAWN	3.2	3%	66%
HUMBLE CITY SOUTH;STRAWN	3.1	3%	69%
CASS;PENN	2.8	3%	72%
BIG DOG SOUTH;STRAWN	2.3	2%	74%

Table 1. Top pools by cumulative oil production. (Source: digitized+dwights)

Northeast Lovington, represent 39% of the total plays oil production. Peak production for these two pools is shown in Figure 1. Table 2 lists the top oil producing pools for 2010. The pools highlighted in blue are not listed in Table 1 and thus are recent developments. Horizontal wells are also indicated; but have not played a significant role in this play.

poolName	2010 oil prod BOPD	horizontal wells	Secondary recovery
LOVINGTON;STRAWN, WEST	411	1	wtr, gas
LOVINGTON;UPPER PENN, NORTHEAST	348		
ARENA ROJA;STRAWN, SOUTH (GAS)	141		
LUSK;STRAWN	109		wtr
HARDY;STRAWN, NORTH	101		
BENSON;STRAWN (GAS)	78		
BIG DOG;STRAWN, SOUTH	75	3	
SHIPP;STRAWN	68		wtr
SHOE BAR;STRAWN, NORTHWEST	61		
SHOE BAR;STRAWN, NORTHEAST	60	1	

Table 2. Top pools by 2010 oil production rate. (Source: digitized+dwights)

Gas pools with cumulative production greater than 10 Bscf are listed in Table 3 and top producing pools for 2010 in table 4.

poolName	Cum_Gas Bscf	percent of total	Cumulative %
LUSK;STRAWN	90.7	13%	13%
LOVINGTON WEST;STRAWN	45.6	7%	20%
CARLSBAD SOUTH;STRAWN	42.4	6%	26%
GOLDEN LANE;STRAWN	36.9	5%	32%
CARLSBAD;STRAWN	35.1	5%	37%
BURTON FLAT EAST;STRAWN	30.7	5%	42%
FRONTIER HILLS;STRAWN	26.6	4%	46%
BURTON FLAT;STRAWN	26.1	4%	49%
SHIPP;STRAWN	22.1	3%	53%
AVALON;STRAWN	19.0	3%	55%
SHUGART;STRAWN	18.5	3%	58%
MOSLEY CANYON;STRAWN	17.4	3%	61%
ANTELOPE RIDGE;STRAWN	15.3	2%	63%
BURTON FLAT WEST;STRAWN	15.0	2%	65%
EAGLE CREEK;STRAWN	10.7	2%	67%
WINCHESTER;STRAWN	10.2	2%	68%

Table 3. Top pools by cumulative gas production. (Source: digitized+dwights)

poolName	2010 gas prod MCFD
ARENA ROJA;STRAWN, SOUTH (GAS)	4218
LOVINGTON;STRAWN, WEST	2041
GOLDEN LANE;STRAWN (GAS)	1303
MOSLEY CANYON;STRAWN (GAS)	1226
BENSON;STRAWN (GAS)	1212
SHUGART; STRAWN	1188
LOVINGTON;UPPER PENN, NORTHEAST	1052
PARKWAY;STRAWN, WEST (GAS)	962
BURTON FLAT;STRAWN, EAST (GAS)	893
SALT DRAW; STRAWN (G)	889

Table 4. Top pools by 2010 gas production rate. (Source: digitized+dwights)

An example of recent development is shown in Figure 3 for the South Arena Roja pool. The addition of two new wells has significantly improved production in this pool to be within the top 2009 gas and oil producing lists.

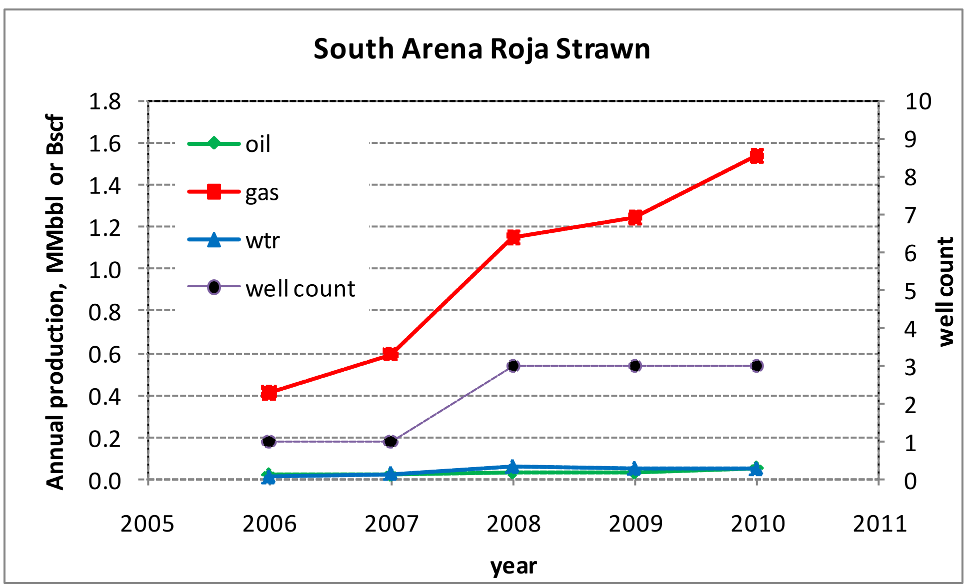


Figure 3. Annual production and well count for South Arena Roja pool. (Source: digitized+dwights)

Despite the success of South Arena Roja, overall activity over the last seven years has been minor (Figure 4) in this play; averaging 17 new completions per year. The maximum was 25 in 2006 and the minimum was two in 2004. The majority of completions are gas wells, and thus with the subsequent decline in gas prices the activity in this play has also declined.

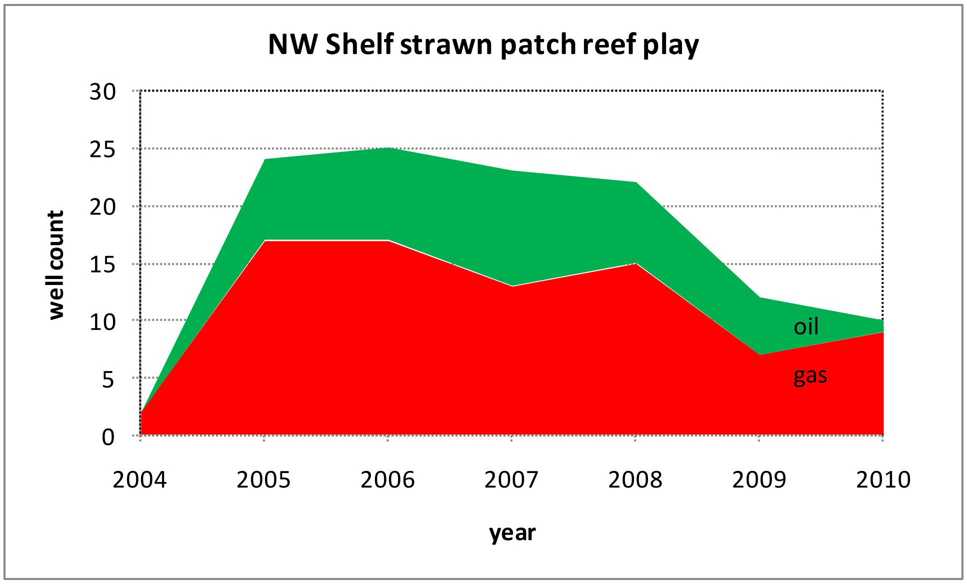


Figure 4. Recent activity in the Northwest shelf strawn patch reef play. (Source: GOTECH)

Several pressure maintenance projects have been implemented in this play; however the majority are small in areal extent and/or short lived; thus results are difficult to assess. Only the West Lovington pool has been the most active and developed pressure maintenance project.

The West Lovington Strawn pool was discovered in 1992(figure 5), but by 1995 the pressure in this solution gas drive reservoir had declined rapidly approaching the critical gas saturation and reducing ultimate oil recovery. Pressure maintenance in the pool was started in 1995 (case no 11194) to mitigate this problem by injecting gas at 2700 psi surface pressure into the Strawn formation, and create a gas cap and thus slow down reservoir energy depletion. Gas injection ended in 2002. In 2009 pressure maintenance was re-initiated by injecting water injection down dip in the reservoir to reinforce the partial water drive.

As can be seen in the production curves in Figure 5, the gas injection project was successful in reducing decline and improving oil recovery.

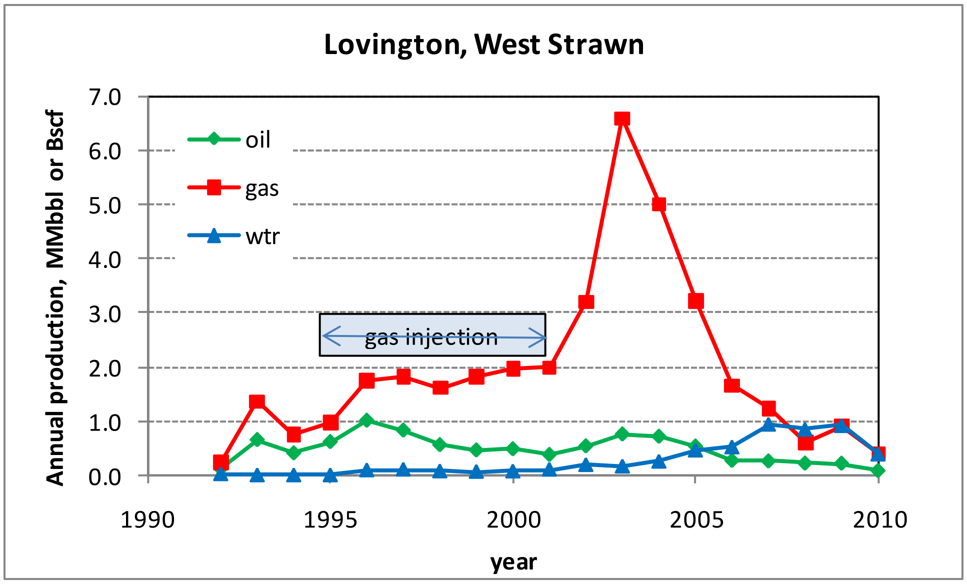


Figure 5. Annual production and well count for the West Lovington Strawn pool. (Source: digitized+dwights)

Predicted Development

Opportunities for additional development such as in South Arena Roja exist, but will be sporadic and minor in overall effect. Neither horizontal well development or secondary recovery have been meaningful.

Pre-Permian Play

BRIEF SUMMARY OF GEOLOGY

The pre-Permian play is confined to the deeper producing horizons in Chaves County (Figure 1). Defined producing formations include the Cisco, Strawn, Pennsylvanian, Permian, Mississippian, Ordovician, Siluro-Devonian, and Silurian.

The development of the Pre-Permian play is based on the occurrence of trapped hydrocarbons found below an unconformable surface near an erosional (pinchout) edge of the lower Paleozoic formations.

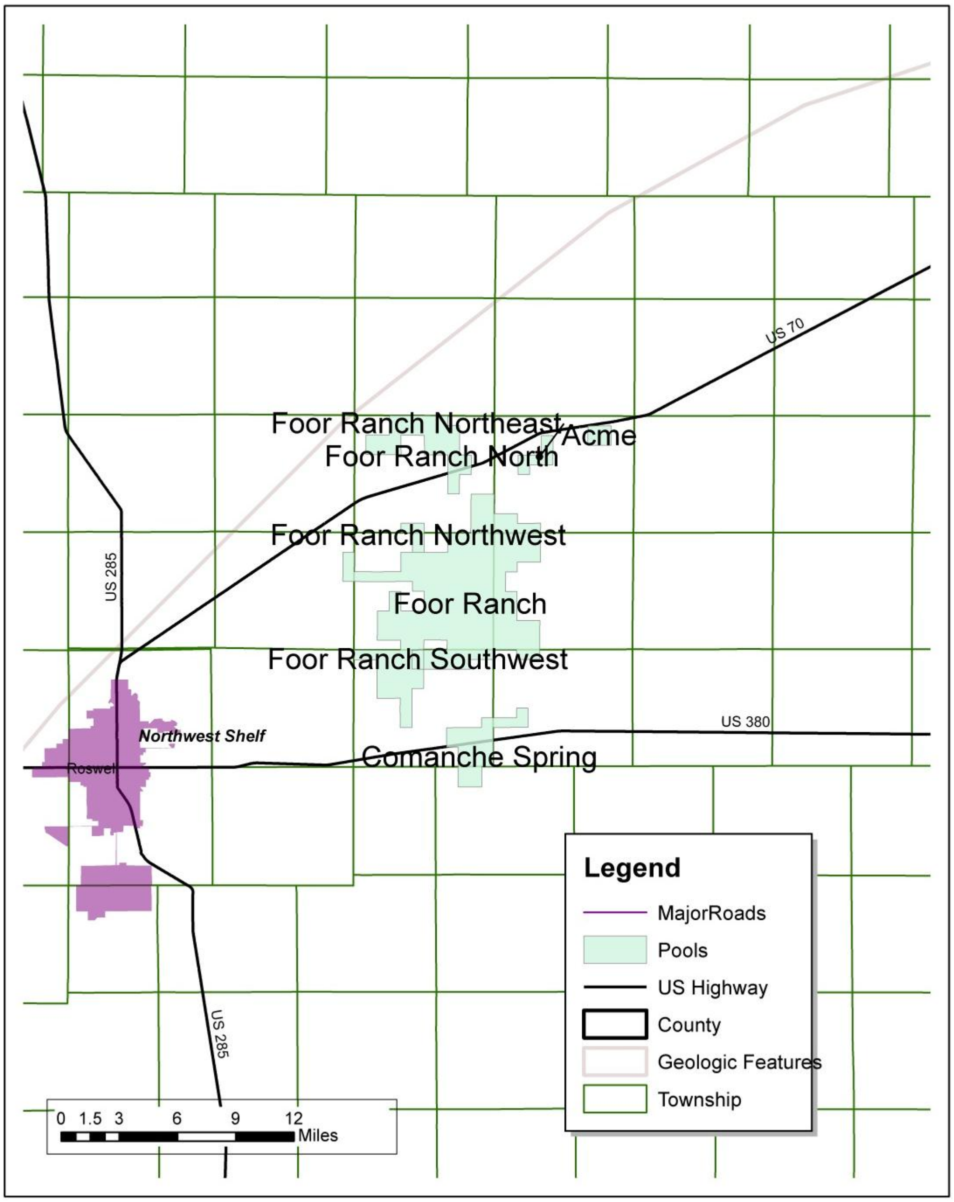


Figure 1. Pre-Permian pool map

Historical Development

Cumulative gas production for this play has been 120 Bscf, with production dominated by the Foor Ranch (Pre-permian) complex, contributing 89% of the cumulative gas production from this pool (See Table 1).

poolName	Gas rate 2010, mscfd	Cum_gas, Bscf	percent	Cum %	Wells_2010
FOOR RANCH;PRE PERMIAN (GAS)	13967	107.40	89%	89%	74
FOOR RANCH; PRE-PERMIAN, N. (G)	214	6.30	5%	94%	9
COMANCHE SPRING;PRE-PERMIAN (GAS)	145	6.20	5%	99%	9
FOOR RANCH; PRE-PERMIAN, NW (G)	49	0.61	1%	100%	2
ACME; PRE-PERMIAN (G)	21	0.24	0%	100%	2
LEA LAKE; PRE-PERMIAN (G)	46	0.09	0%	100%	1
FOOR RANCH; PRE-PERMIAN,NE (G)	26	0.04	0%	100%	2
FOOR RANCH; PRE-PERMIAN, SW (G)	0	0.00	0%	100%	1

Table 1. Cumulative gas production, 2010 gas production rate and well count for pools designated in the Pre-Permian gas play. (Data Source: Dwights)

The Foor Ranch pool was discovered in 1981. In 2000-01, additional development occurred in the Foor Ranch (Penn) pool and new development in the Foor Ranch (Permian) and (Silurian) pools; in response to the increase in gas price (Figure 2). With recent gas prices depressed the development in this play has dropped dramatically.

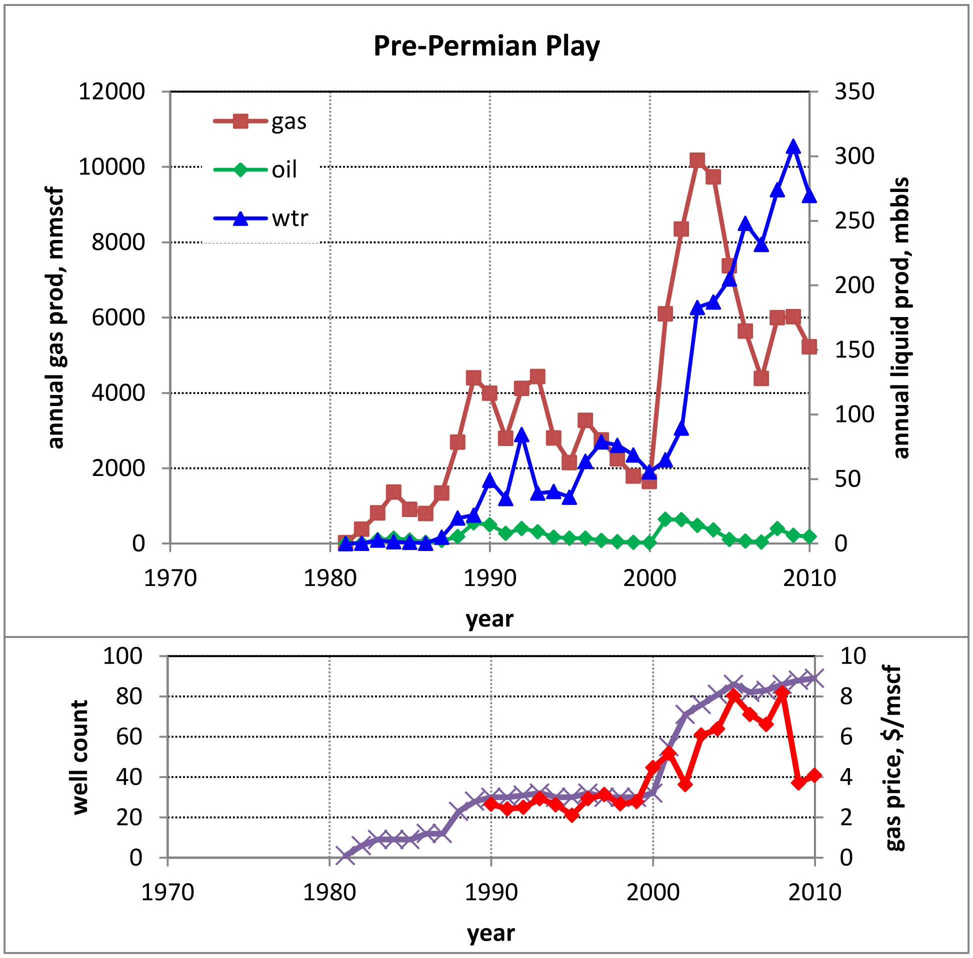


Figure 2.Annual oil, gas and water production curves, well count and gas price for the Pre-Permian play. (Data Source: Dwights, EIA)

Predicted Development

Pre-Permian activity has been minor since 2004 (Figure 3), averaging only 3 new well completions per year. The spike in 2005 was additional development in Comanche Springs and Foor Ranch pools in response to stable gas prices. Since projections for natural gas prices are too remain relatively constant, there is no economic incentive to develop these gas pools. As a result predicted completions will remain low. Furthermore, the pools have limited expansion capabilities, and thus development will more likely be infill drilling, which requires a better gas price. As a result the Pre-Permian is not a primary target for development.

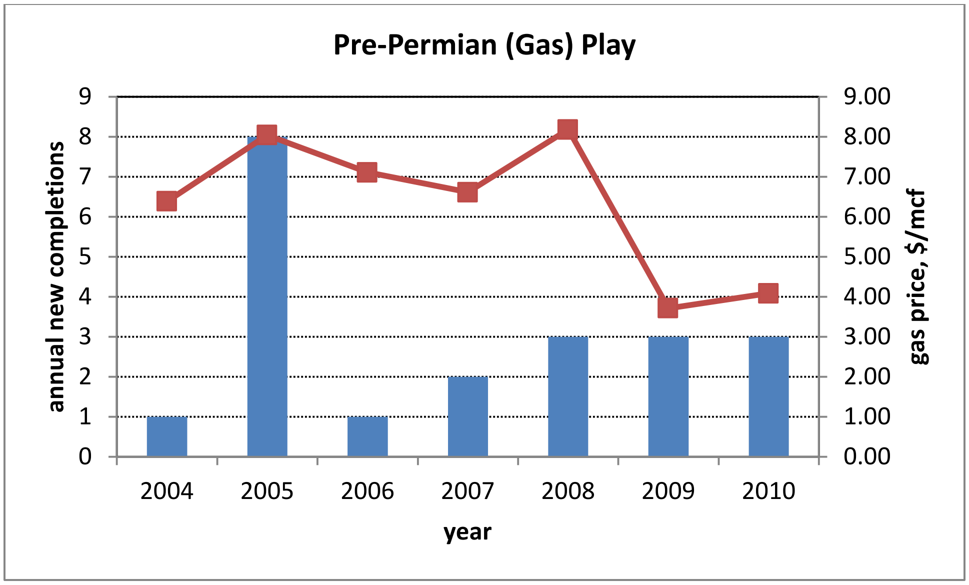


Figure 3. Pre-Permian well completions correlated with wellhead gas prices from 2004 to 2010. (Data Source: GOTECH and EIA)

Upper San Andres and Grayburg Platform Mixed-
Artesia Vacuum Trend Play

The future potential for this play is ***moderate***.

Brief Summary of Geology

Reservoirs in this play extend in an east to west direction along the Artesia-Vacuum arch; a shallow east-west trending structure that overlies the deeper, older Abo shelf edge reef trend and Bone Spring flexure (Broadhead, 1993).

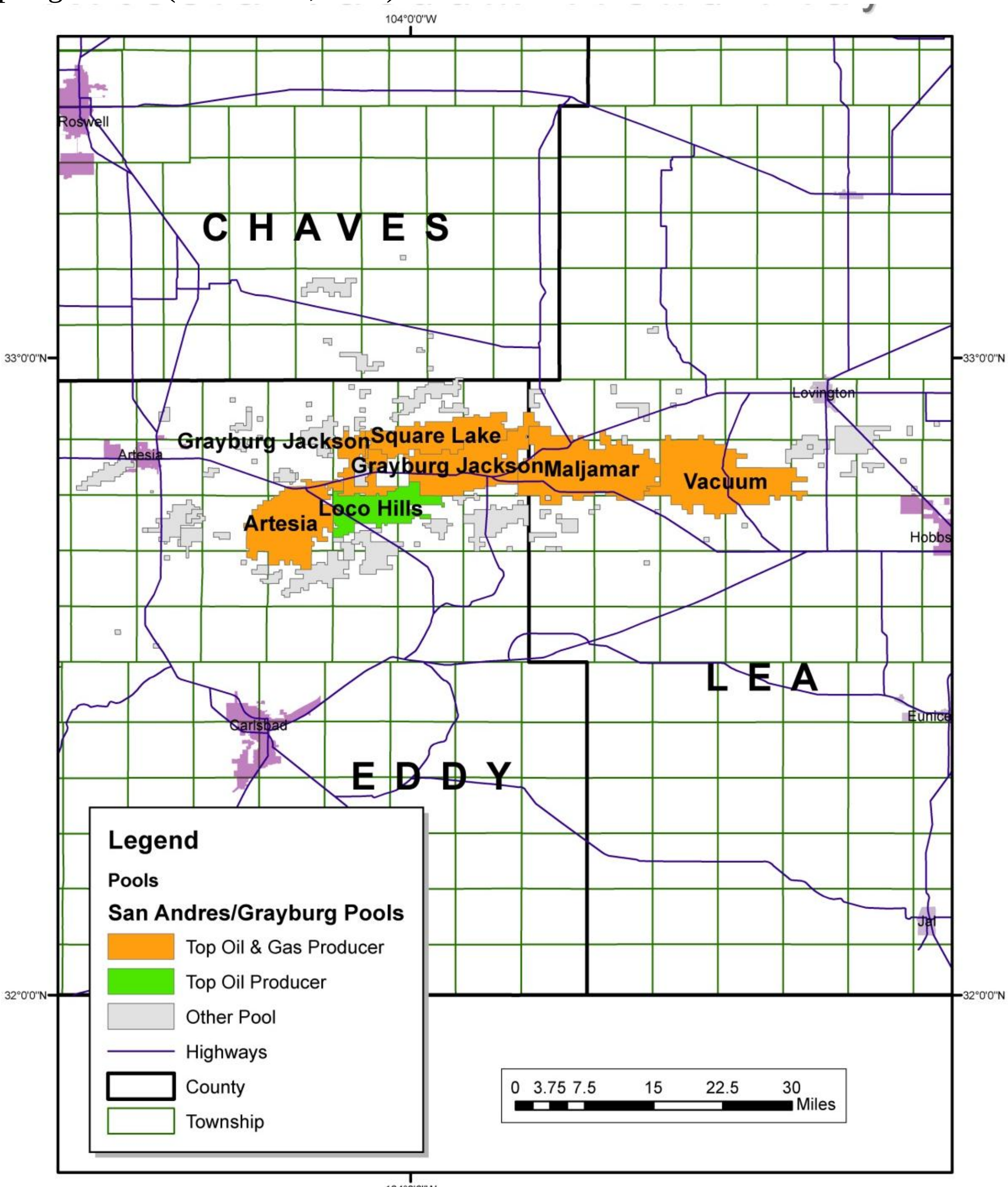


Figure 1. Pool map for the Upper San Andres and Grayburg Platform Mixed-Artesia Vacuum Trend Play

The San Andres Formation is characterized as a sequence of carbonate depositional cycles with production in the San Andres principally from the dolostones. As a result, the reservoir zones in the San Andres exhibit lateral as well as vertical variation in permeability. The Grayburg Formation consists of interbedded sandstones, siltstones, dolomitic carbonates, and evaporates with the majority of production from the sandstones.

Traps are a combination structural and stratigraphic. The position of the reservoir with respect to the axis of the Artesia-Vacuum arch dictates whether the Grayburg Formation or the upper part of the San Andres Formation is more productive. Those reservoirs located along the crest (e.g. Maljamar, Vacuum, Grayburg-Jackson) have sufficient structural elevation for the Grayburg and upper San Andres Formations to be in the oil zone, while on the flanks of the structure the San Andres is wet and only the overlying Grayburg is in the regional oil leg (Broadhead, et al, 2004). The updip porosity pinchout into the evaporitic lagoonal facies create the stratigraphic trapping component (Ward et al., 1986).

HISTORICAL DEVELOPMENT

Production in this play began in 1945 in the Vacuum, Maljamar and Lovington pools. Since then almost 100 pools have reported production from the Grayburg/San Andres in this trend; with cumulative production through 2010 of 842 MMBO (includes pre-1945 oil production), 1 TCF, and 1928 MMBW. Figure 2 shows the performance and activity of this play since 1945.

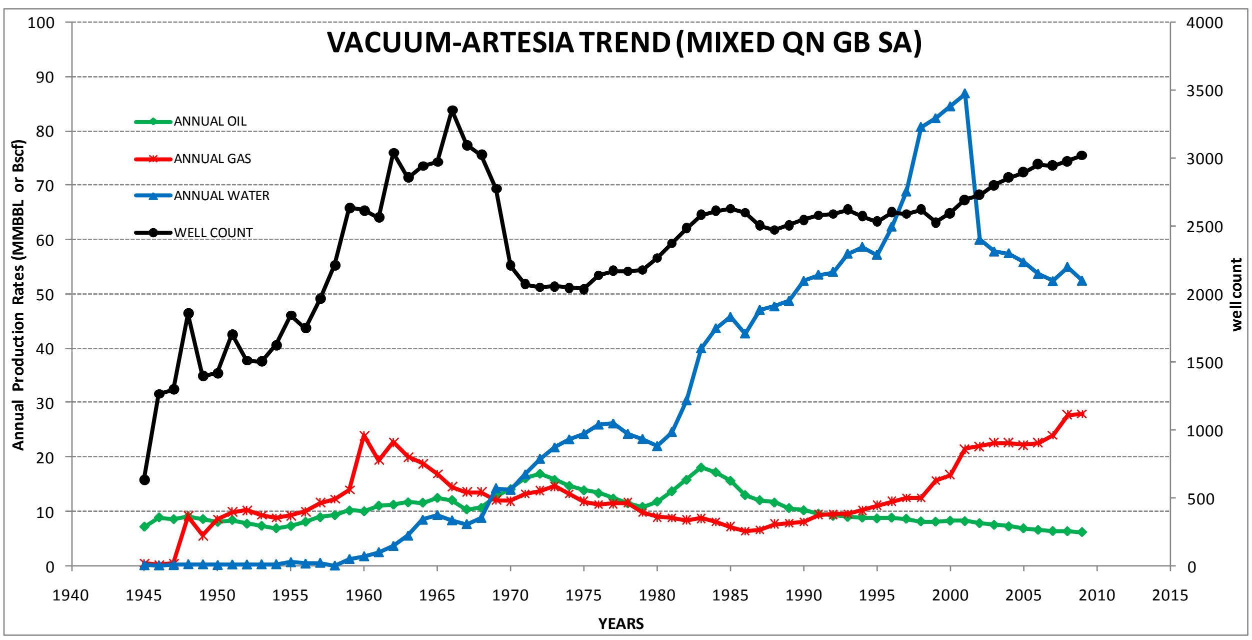


Figure 2. Annual production and well count for the Vacuum-Artesia (GB/SA) trend. (Source: digitized+dwights)

The top oil producing pools are listed in Table 1. These six pools represent 91% of the play's total oil production, thus dominating the play's production.

poolName	Cum_Oil* MMBO	percent of total	Cumulative %
VACUUM;GRAYBURG SAN ANDRES	388	46%	46%
MALJAMAR;GRAYBURG SAN ANDRES	166	20%	66%
GRAYBURG JACKSON;SR Q G SA	123	15%	80%
ARTESIA;QUEEN GRAYBURG SAN ANDRES	31	4%	84%
SQUARE LAKE;GRAYBURG SAN ANDRES	25	3%	87%
LOCO HILLS;GRAYBURG SAN ANDRES	21	3%	90%
LOCO HILLS;QUEEN GRAYBURG SAN ANDRE	15	2%	91%

Table 1. Top pools by cumulative oil production. (Source: digitized+dwights)

Peak production for these pools is shown in Figure 3. The maximum peak occurred in 1983 at ~50,000 bopd, primarily due to the Vacuum pool development.

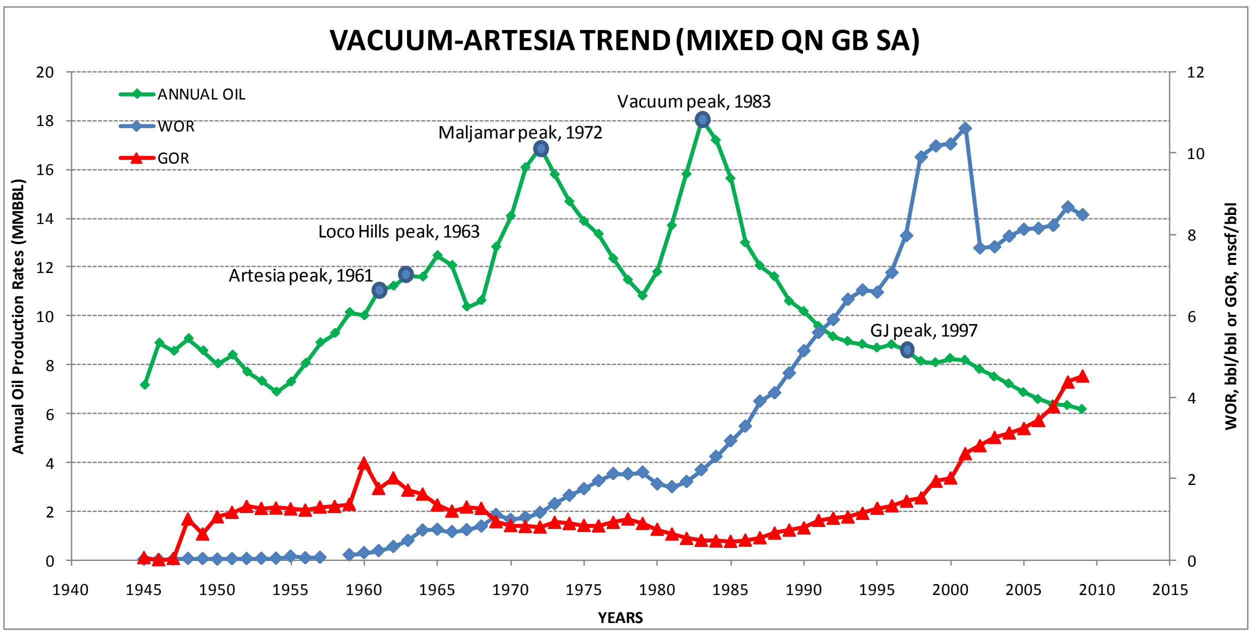


Figure 3. Annual oil production, WOR and GOR for the Vacuum-Artesia (GB/SA) trend. (Source: digitized+dwights)

Top oil producing pools in 2010 are shown in Table 2. Three pools, Shugart, Red Lake and East Millman (highlighted in green), are not in the top cumulative pool production list (Table 1) due to recent development.

poolName	2010 oil rate BOPD	2010 WOR
VACUUM;GRAYBURG SAN ANDRES	10330	10
GRAYBURG JACKSON;SR Q G SA	4601	5
MALJAMAR;GRAYBURG SAN ANDRES	2638	7
RED LAKE;QUEEN-GRAYBURG-SA	1142	8
ARTESIA;QUEEN GRAYBURG SAN ANDRES	630	7
SHUGART;YATES-7RS-QU-GRAYBURG	598	12
MILLMAN EAST;QUEEN GRAYBURG SAN AN	521	9
SQUARE LAKE;GRAYBURG SAN ANDRES	299	7
LOCO HILLS;QUEEN GRAYBURG SAN ANDRE	237	15

Table 2. Top pools by 2010 oil production rate. (Source:GOTECH)

The reservoir drive mechanism for the majority of these pools is solution gas drive. After primary recovery significant oil-in-place remained; therefore many of these reservoirs in this play have been successfully waterflooded. All of the pools listed in Table 1 have been waterflooded at some period of time. Furthermore, enhanced recovery techniques have been implemented in several of the reservoirs in this play. CO_2-EOR flooding has been employed in portions of the Vacuum and Maljamar reservoir with positive results (Pranter et al., 2004). As a result of injection the producing WOR has increased significantly. Notice in Figure 3 the WOR has been increasing since the 1960s to a little more than 8 barrels of water per barrel of oil in 2010. Future projections must account for this increase in water production.

The largest of the Grayburg/San Andres reservoirs is the Vacuum San Andres in Lea County; responsible for almost half of the total oil production from the play. Figure 4 exhibits the production and injection for the entire reservoir. Well spacing is a strong function of the complex horizontal and vertical compartmentalization of flow units that formed as a result of cyclic deposition of permeable and impermeable facies. In response, full development of reservoirs with vertical wells has been on 20-acre spacing or less.

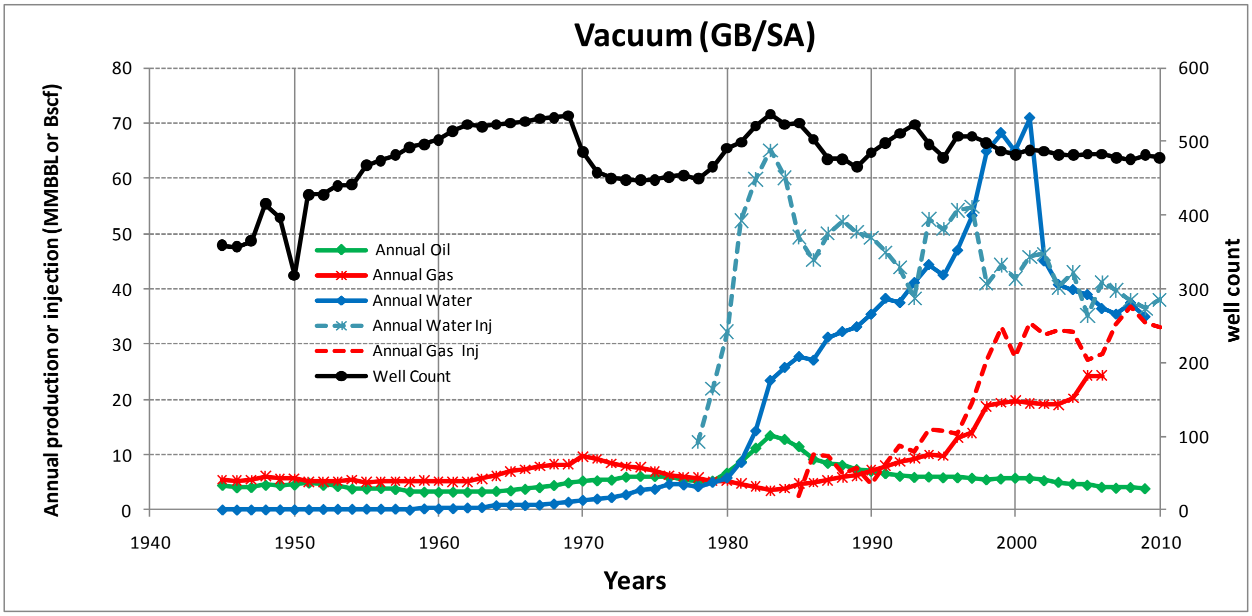


Figure 4. Annual production and well count for the Vacuum San Andres pool. (Source: digitized+dwights)

The massive size of the Vacuum reservoir led to the development of various units to operate efficiently. The location of the units is outlined in figure 5. East (EVGSA) and Central (CVU) Vacuum are the largest and most prolific of the units. Table 3 provides a summary of the secondary and tertiary development in these and other units.

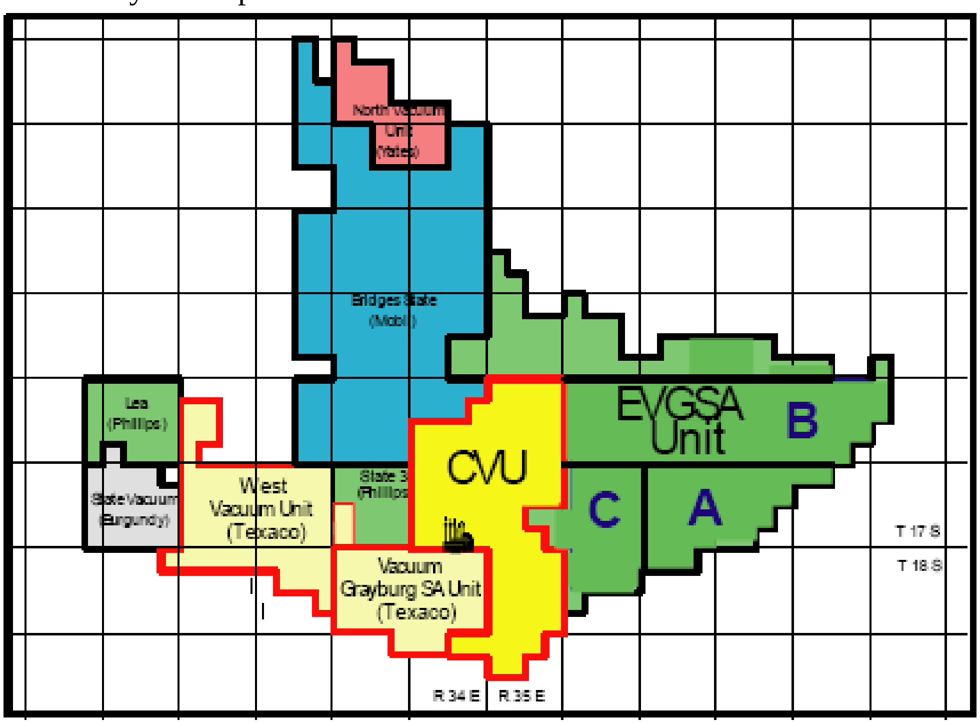


Figure 5. Schematic of the various production units within the Vacuum GB/SA reservoir. (ARI,2006)

	ConocoPhillips (VGSAU & CVU)	ChevronTexaco (EVGU & WVGU)	Mobil Oil (Bridges State Unit)
Pressure Maintenance	2000 (with water, CO2 and produced gases)		1972
Unitized/Waterflood	Pilot (1965) Full Scale (1968-1971) 1973 (VGSAU) 1978 (CVU) Project expansion (1992 and 1998)	1973 (EVGU)	Pilot (1958) Full scale (1967) Project Expansion (1987-19992)
CO_2-EOR (MPZ)	2007 (VGSAU)	Pilot 1985 (EVGU) Full scale 1997 (with water, CO_2 and produced gases)	
CO_2-EOR (ROZ)	2008	Proposed 2011	

Table 3. History of secondary and tertiary development for several units in the Vacuum reservoir

Previous work (Pranter et al., 2004) proposes that vertical and horizontal compartmentalization has resulted in significant bypassed pay that has not been drained adequately by vertical wells or completely swept during enhanced recovery. Subsequently, horizontal laterals aimed at intersecting undrained pay were drilled from an existing vertical well and resulted in an increase in production of approximately 20-fold compared to what the pre-existing vertical well yielded Production from existing vertical offset wells was not affected by the newer lateral wells, indicating that the lateral wells penetrated untapped reservoir compartments. Rather than drill the horizontal laterals as flat segments, they were drilled in a serpentine pattern so that multiple vertical reservoir compartments are penetrated by a single wellbore (Broadhead, et al, 2004).

Well activity since 2004 is shown in Figure 7. For this seven year time period, 608 completions occurred or approximately 90 per year. Development in the Grayburg-Jackson pool is responsible for 25% of the total completions and for the peak in activity in 2006. The latest increasing trend in 2010 is due to additional development in Grayburg-Jackson, Loco Hills and Red Lake pools.

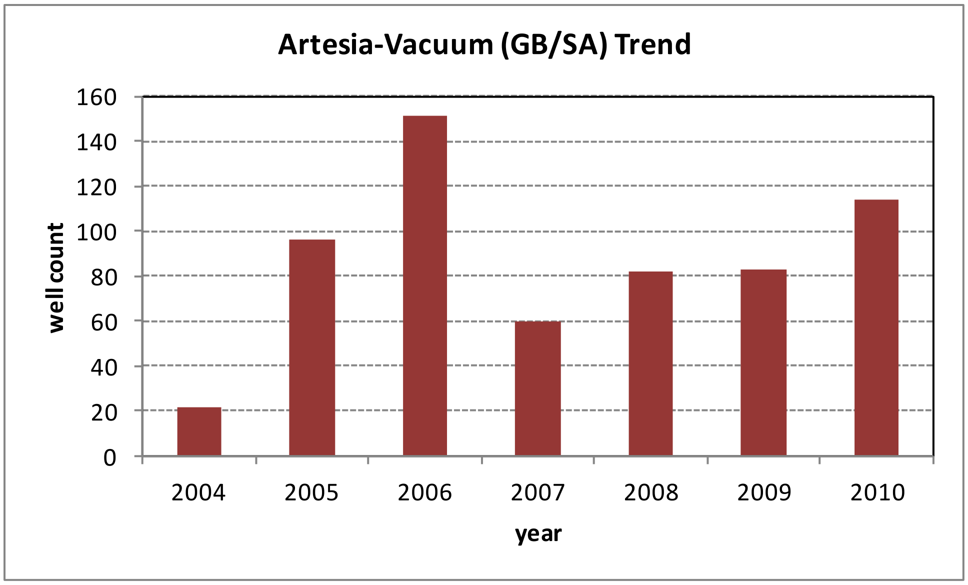


Figure 7. Annual new completions for the Artesia-Vacuum (GB/SA) Trend. (Data source: GOTECH).

FUTURE DEVELOPMENT

Future well development is predicted to remain constant at approximately 100 new completions per year. As shown in Figure 8, the majority of this future development is anticipated to occur in the main trend body from Vacuum to Grayburg-Jackson. The majority of activity is infill wells in large established units either for downspacing or waterflood pattern development. An example of the later is in Vacuum field where the regular 40 acre inverted five-spot pattern was converted into a direct line drive injection pattern. Other activity will be for developing lower permeability Grayburg sandstones. An example is the Grayburg Jackson reservoir where during the mid-1990's development of these sandstones was successful to the point of reversing production decline. Horizontal wells have been successful for the few locations attempted; but are not predicted to have a significant impact due to the shallow depth and multiple, stacked reservoirs of these pools.

The majority of pools in this trend have been waterflooded; particularly the large units. These are mature waterfloods and thus the water-oil ratio is high, ranging from 5 to 15 barrels of water produced for every barrel of oil (Table 2). Water disposal and injection facilities will be in need of upgrades and/or expanded.

CO_2 pipeline infrastructure has been developed to the Maljamar field from the Cortex Pipeline that carries CO_2 from McElmo Dome in Southwest Colorado. Additional lateral extensions will be required to develop tertiary recovery in nearby fields in the trend. A report by ARI in 2006 identified significant tertiary (EOR-CO_2) potential for the Grayburg/San Andres pools of New Mexico.

Additional potential is available in the deeper residual oil zones of the GB/SA (See Results/Discussion section for more information on ROZs). The resource potential currently existing in the residual oil zones along the Vacuum-Artesia trend is estimated to be about 4.5 billion barrels. Existing wellbores that penetrate the ROZ or deepening of existing wellbores will be necessary to acquire this potential. Thus both the main pay zone and the residual oil zone can be CO_2 flooded to increase recovery along the trend.

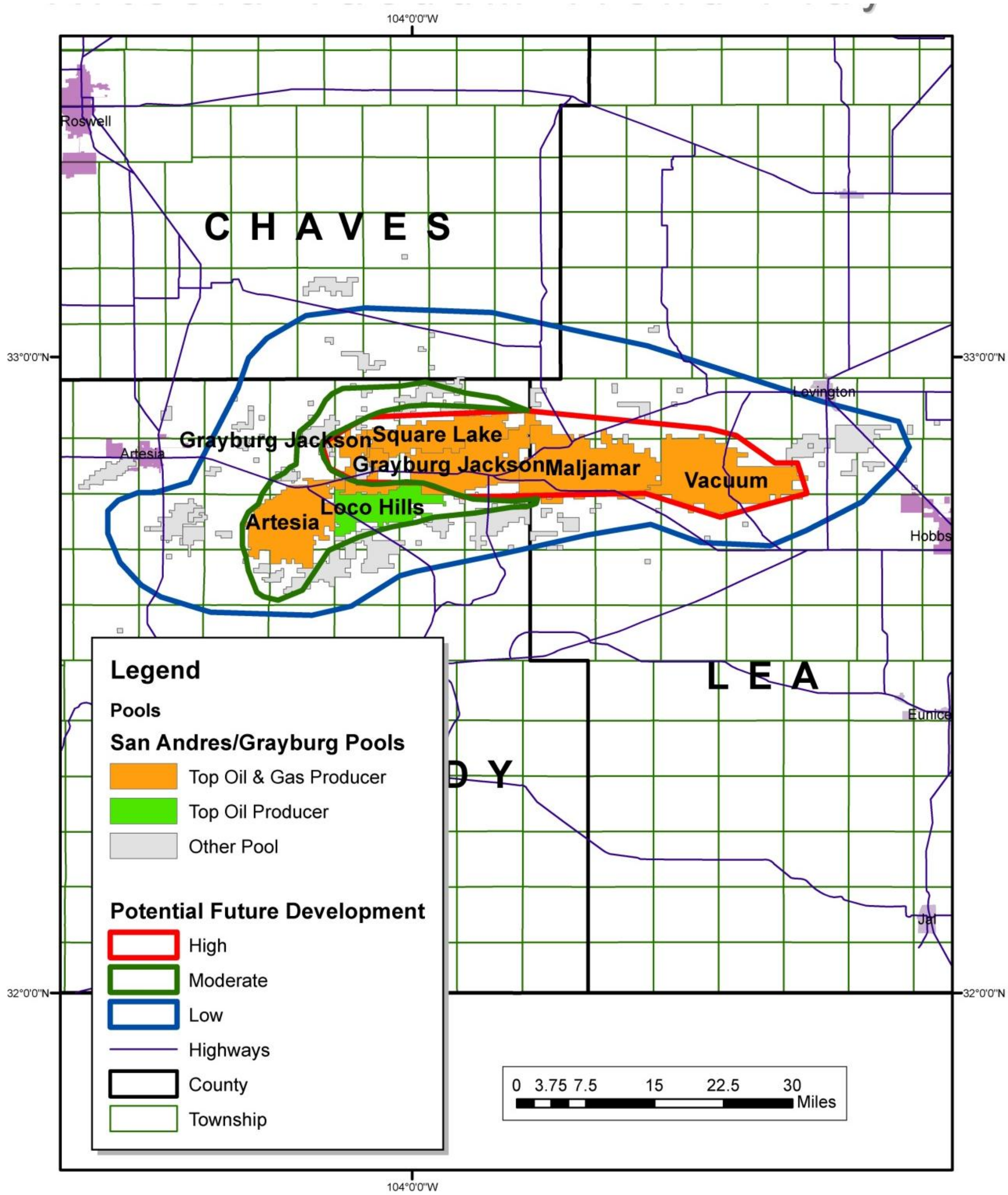


Figure 8. Potential map for the Artesia-Vacuum GB/SA Play. Red line – high, green line – moderate, and blue line – low potential for development.

Upper San Andres and Grayburg Platform Mixed- Central Basin Platform Trend Play

BRIEF SUMMARY OF GEOLOGY

The Upper San Andres and Grayburg (GB/SA) Platform Mixed—Central Basin Platform (CBP) Trend is located on the northwestern part of the Central Basin Platform in Lea County (see figure 1). Initially discovered in the 1920s, the majority of these reservoirs are very mature and have been extremely prolific with cumulative production through 2010 of 844 MMBO (includes pre-1945 oil production), 1,867 Bscf, and 4,333 MMBW from 42 defined pools. High water production is due to natural water drive and implementation of several large pressure maintenance projects in the GB/SA in this play.

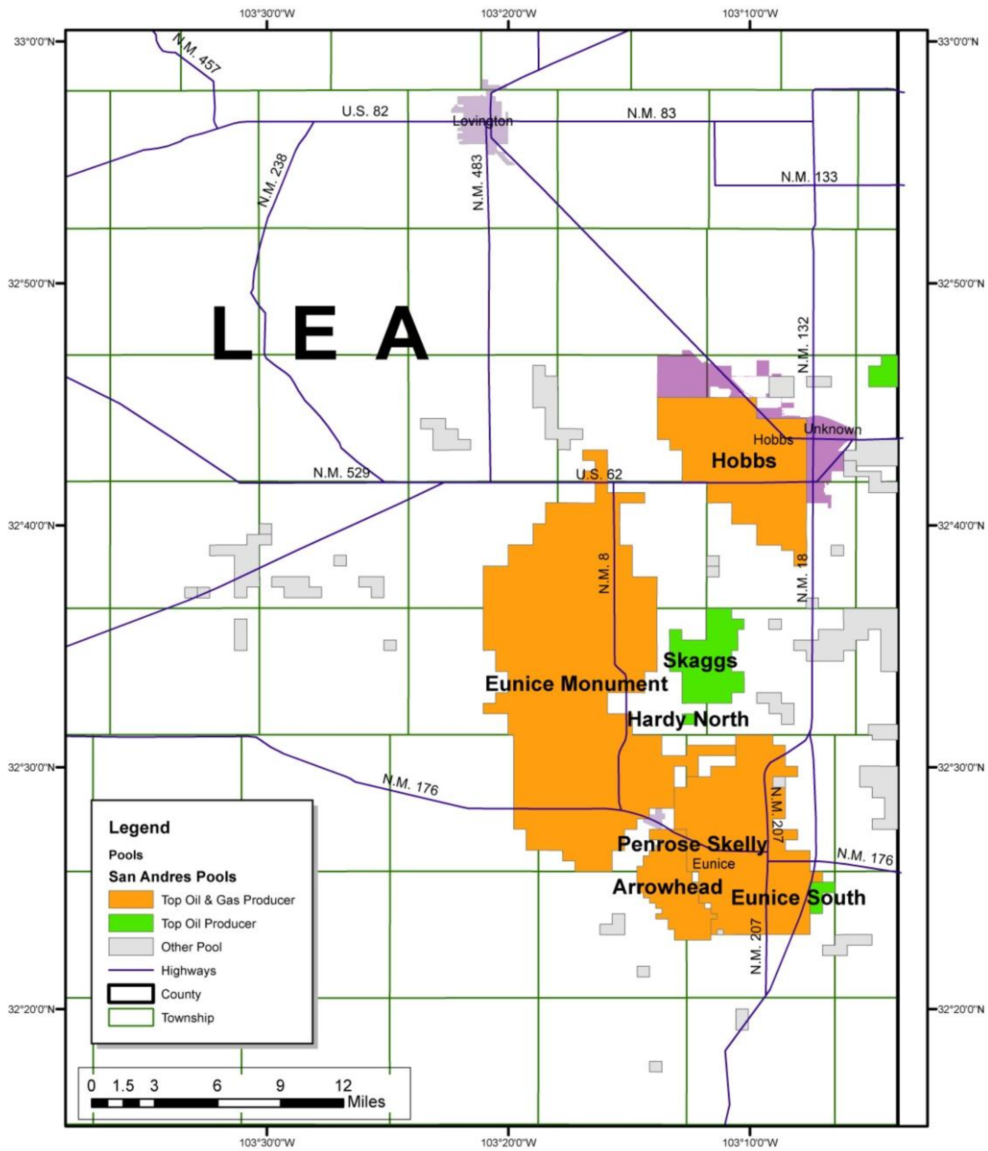


Figure 1. Pool map for Upper San Andres and Grayburg Platform Mixed- Central Basin Platform Trend Play

Reservoirs of the upper San Andres and Grayburg Formations are primarily shallow marine dolomites and dolomitic sandstones. Typically these reservoirs are characterized as heterogeneous both vertically and laterally. Traps are mainly formed by gentle, north-south trending anticlines, with evaporates above forming an impermeable seal. Porosity is generally intergranular to intercrystalline with locally developed secondary porosity present. The dominant production mechanisms in the play are water drive and solution gas drive. Waterflooding and pressure maintenance have been successfully implemented in many of the reservoirs in this play and have resulted in substantial increases in recovery.

Historical Development

The production from this play is dominated by two pools; the Eunice-Monument and the Hobbs. As shown in Table 1, both have exceeded 200 MMBO in cumulative oil production, and account for 87% of the total play's oil production. The remaining 32 pools in this play account for less than 1% of the total oil production, and thus are minor in comparison.

poolName	Cum_Oil MMBO	percent of total	Cumulative %
HOBBS;GRAYBURG / SAN ANDRES	378	45%	45%
EUNICE MONUMENT;GRAYBURG / SAN ANDRE	360	43%	87%
ARROWHEAD;GRAYBURG	38	5%	92%
PENROSE-SKELLY;GRAYBURG	39	5%	97%
SKAGGS;GRAYBURG	12	1%	98%
HOBBS EAST;SAN ANDRES	7	1%	99%
CARTER SOUTH;SAN ANDRES	2	0%	99%
EUNICE SOUTH;SAN ANDRES	2	0%	99%
HARDY;QUEEN,GRAYBURG	1	0%	99%

Table 1. Top oil producing pools by cumulative production through 2010 (Data Source: digitized+Dwights).

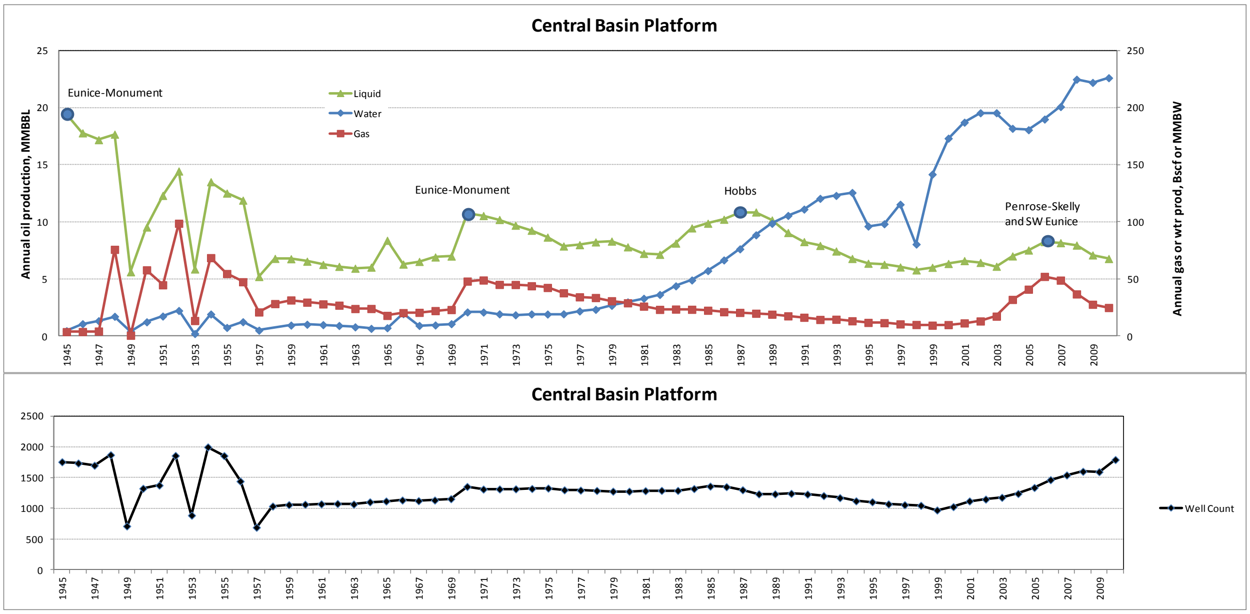


Figure 2. Annual oil, gas and water production and well count for the CBP GB/SA play. (Data source: dwights+digitized).

Both are mature reservoirs, initially developed prior to 1945 (see Figure 2). However, despite this long history, both were the top producing pools in 2010 (Table 2). Also listed in Table 2 is the 2010 producing WOR. High WORs are due to the active water drive and secondary recovery - water injection projects.

poolName	2010 oil rate BOPD	2010 WOR
HOBBS;GRAYBURG / SAN ANDRES	10237	38
EUNICE MONUMENT;GRAYBURG / SAN ANDRE	4861	25
PENROSE-SKELLY;GRAYBURG	1762	15
ARROWHEAD;GRAYBURG	428	100
HOBBS EAST;SAN ANDRES	349	22
EUNICE SOUTH;SAN ANDRES	269	17
SKAGGS;GRAYBURG	235	9
EUNICE SOUTHWEST;SAN ANDRES	172	76
EUNICE;SAN ANDRES	61	70

Table 2. Oil producing rate and WOR for the top pools in 2010. (Data source: GOTECH)

The Eunice Monument reservoir is a combination trap. It was formed by anticlinal closure on the west, north and south and stratigraphic pinchout to the east where porous dolograinstones are sealed updip by impermeable evaporates and limestones.

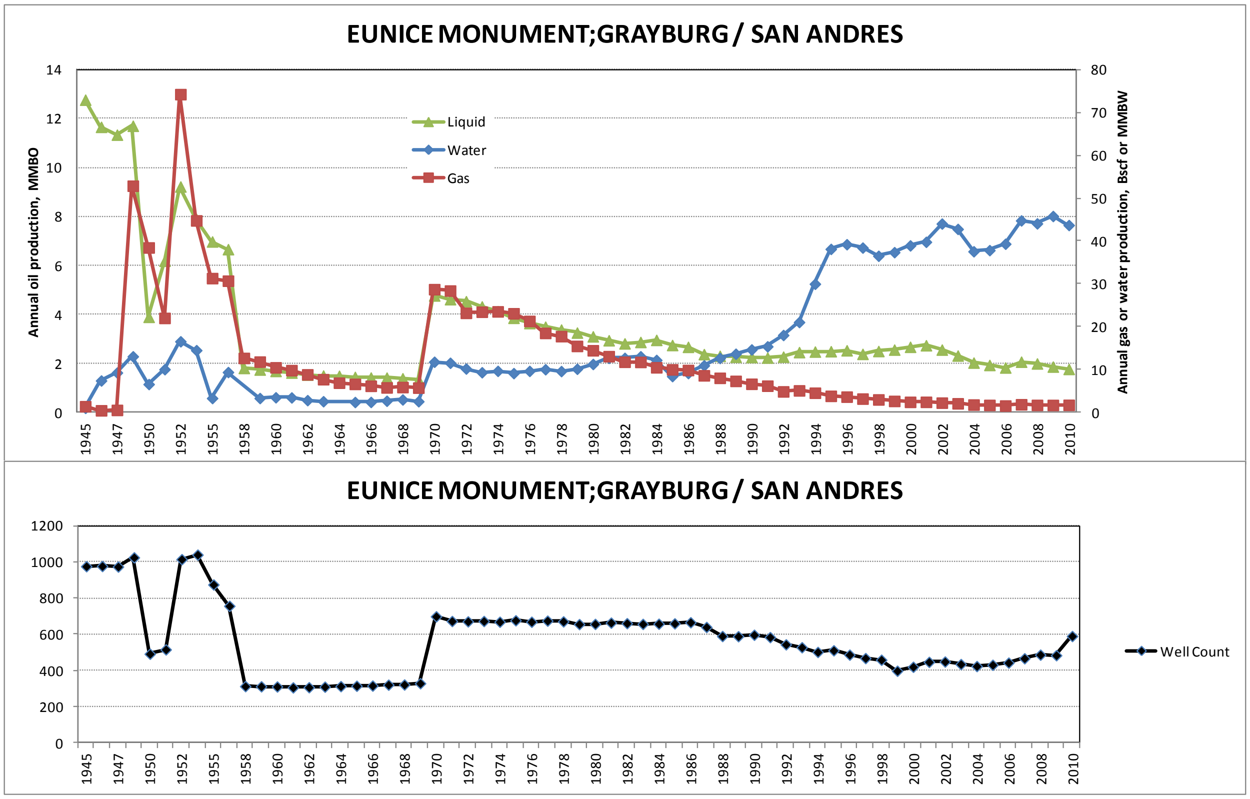
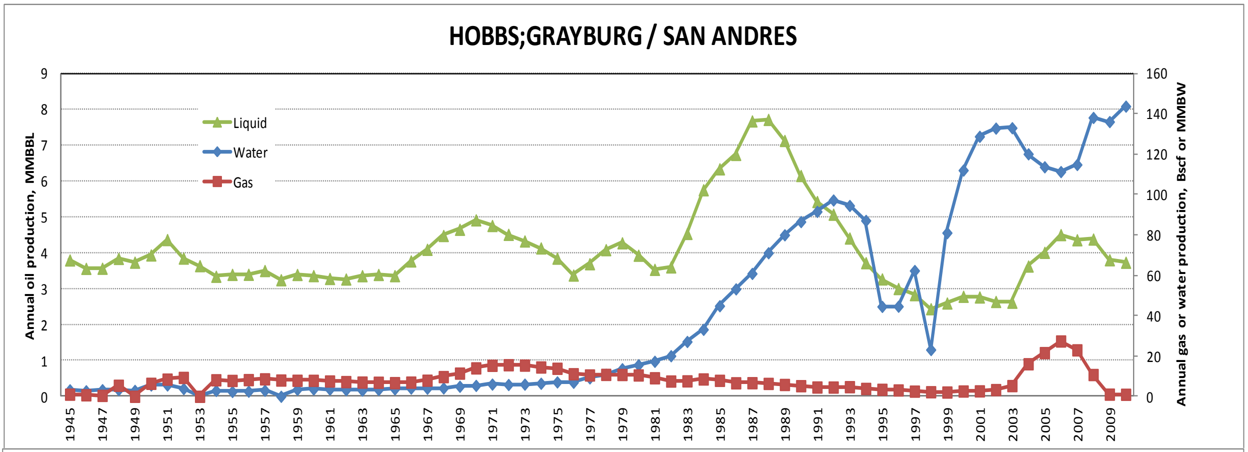


Figure 3. Annual oil, gas and water production and well count for the Eunice – Monument GB/SA pool. (Data source: dwights+digitized).

As shown in figure 3, initial development was prior to 1945. A successful re-development phase occurred in the early 1970s, doubling production and later water flood development in the 1980s arrested the oil decline and increased the corresponding water production. Combined primary and secondary recovery is estimated to be 21% of the OOIP or 414 MMstb.

San Andres production from the Hobbs reservoir commenced in 1930 from the uppermost part of the San Andres, which shows evidence of fractures, large vugs, and small pockets of breccias. Figure 4 shows the very long primary production history before waterflooding began in the late 1970s. Waterflood response was outstanding, reaching a peak production rate of 21Mstbd in 1988. Combined primary and secondary recovery is estimated to be 40% of the OOIP or 352 MMstb. Identified as having favorable reservoir properties for CO_2-EOR, the North Hobbs Unit commenced tertiary recovery operations in 2004. Estimated recovery is an additional 15% of the OOIP.



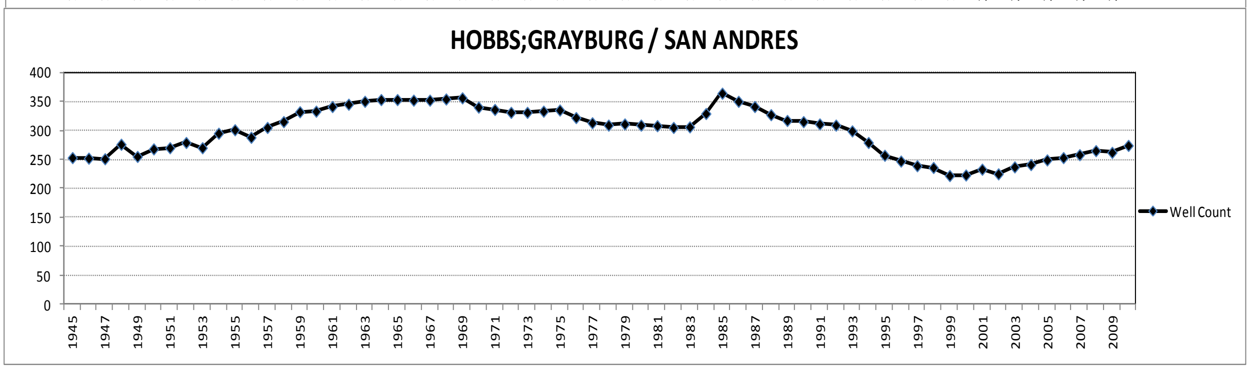


Figure 4. Annual oil, gas and water production and well count for the Hobbs GB/SA pool. (Data source: dwights+digitized).

The cumulative gas production for this play has been approximately 1.87 Tscf; the majority of which is associated gas in the large oil pools. Table 3 lists the top gas producing pools for 2010.

poolName	2010 gas rate MCFD	2010 wells
PENROSE-SKELLY;GRAYBURG	38891	540
EUNICE SOUTHWEST;SAN ANDRES	12657	81
EUNICE MONUMENT;GRAYBURG / SAN ANDRES	4850	590
HOBBS;GRAYBURG / SAN ANDRES	2733	274
EUNICE;SAN ANDRES	2687	23
EUNICE SOUTH;SAN ANDRES	2619	48
SKAGGS;GRAYBURG	909	54
ARROWHEAD;GRAYBURG	783	65
HOBBS EAST;SAN ANDRES	476	36

Table 3. Gas producing rate and well count for the top pools in 2010. (Data source: GOTECH)

Recent Activity

Approximately 500 wells have been drilled in this play from 2004 through 2010 (See Figure 5). The majority (46%) were in the Penrose – Skelly (Grayburg) Pool. The activity in the Penrose – Skelly pool has significantly increased production and as a result has become a top oil and gas producing pool for 2010 (See Tables 2 and 3). A similar trend was also observed in the Southwest Eunice (San Andres) pool.

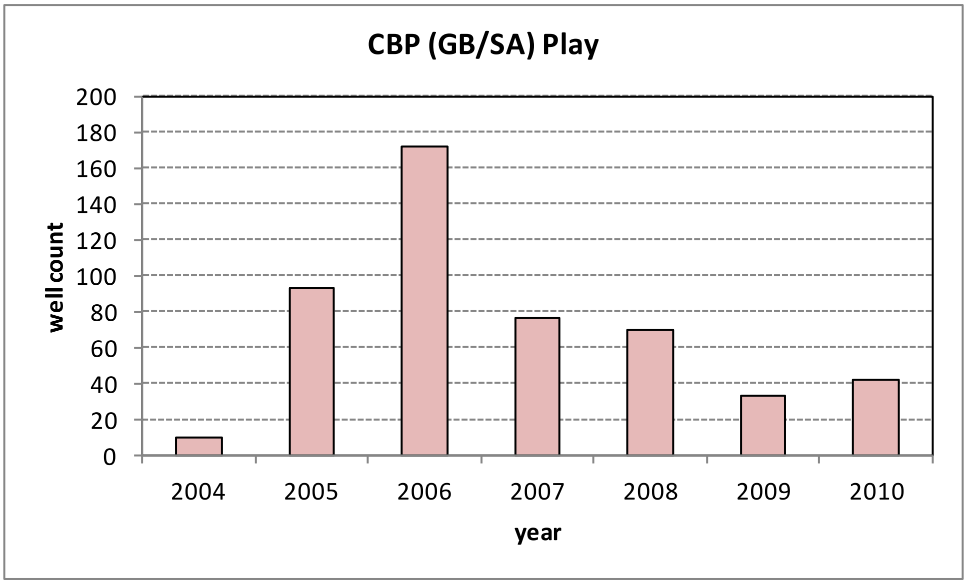


Figure 5 Recent well activity for the CBP (GB/SA) play. (Data source: GOTECH)

Horizontal wells have been a minor component in this play's development, with only 13 horizontal wells drilled since 1996, the majority (9) in the Penrose – Skelly (GB) pool. The average horizontal well has produced 35 Mstb and 300 MMscf.

FUTURE DEVELOPMENT

Future activities are expected to be confined to the development/infill drilling in the major pools and expansion of infrastructure, particularly injection facilities for CO_2 recovery. The Eunice-Monument GB/SA pool has been identified as a highly favorable candidate for CO_2-EOR, with potential of recovering 200 MMbbls of oil (assuming a tertiary recovery of 10% of OIP). Limiting factors are the lack of available CO_2 and the pipeline to transport the CO_2 to the field. However, since the potential oil recovery is significant, it is anticipated these obstacles will be overcome within the next twenty years.

The map in Figure 6 illustrates the potential in the Eunice-Monument, Hobbs, and Penrose pools.

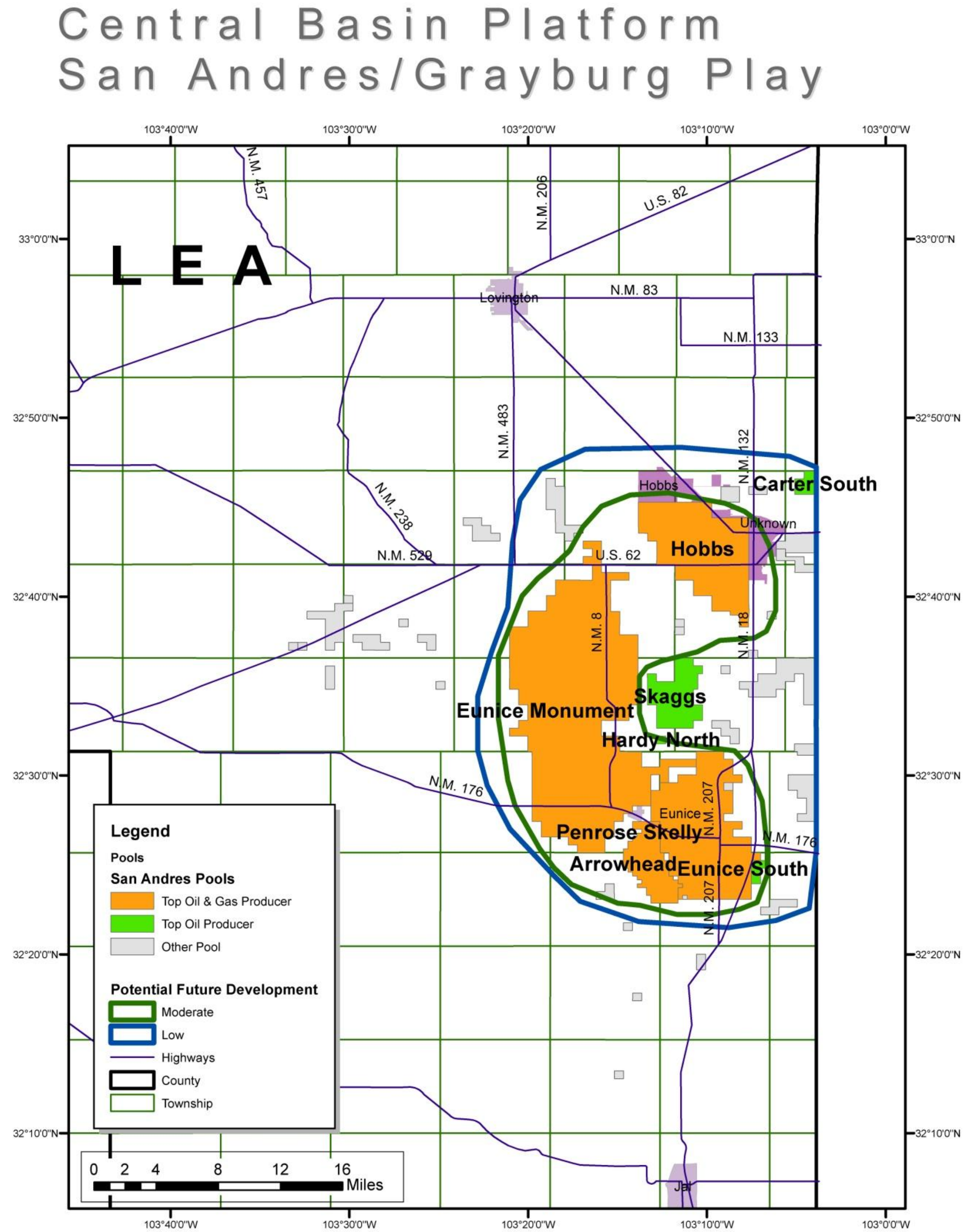


Figure 6. Potential map for the Central Basin Platform (GB/SA) Play. Green line – moderate potential, blue line – low potential

Northwest Shelf San Andres Platform Carbonate Play

Future potential is limited.

Brief Summary of Geology

The Northwest Shelf San Andres Platform Carbonate play extends from the prolific Levelland-Slaughter pools of West Texas to Roswell, New Mexico (Figure 1). The quality of the reservoir follows a similar trend, decreasing westward.

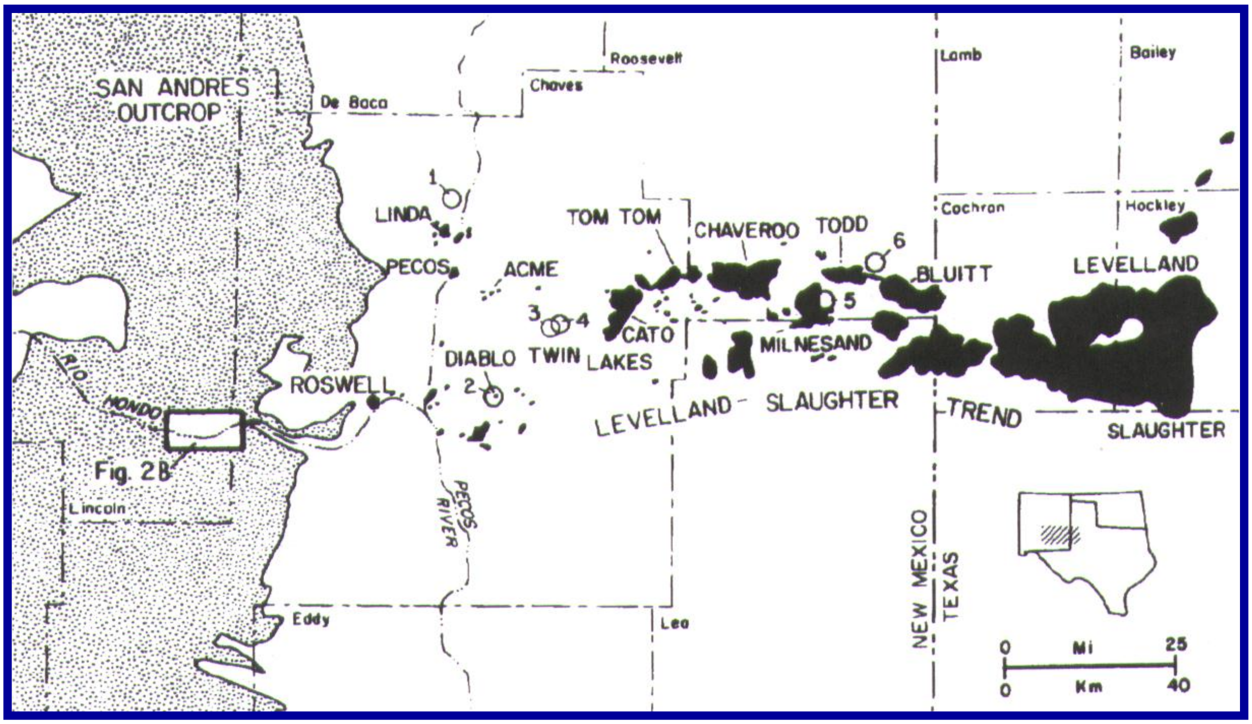


Figure 1. Levelland-slaughter trend of the Grayburg/San Andres of the Northwest Shelf (Elliot, 1989)

The San Andres is divided into upper and lower members (Figure 2). The non-productive upper member is a series of interbedded evaporates, siliclastics, and dolomites. The lower member is a cyclic series of evaporates and carbonates. The slaughter subplay payzones are located in the lower San Andres. Depths to top of reservoirs in New Mexico range from 2000 to 5000 ft. Porosity in the reservoir facies is mostly intercrystalline and moldic, with the best porosity in the dolomite facies.

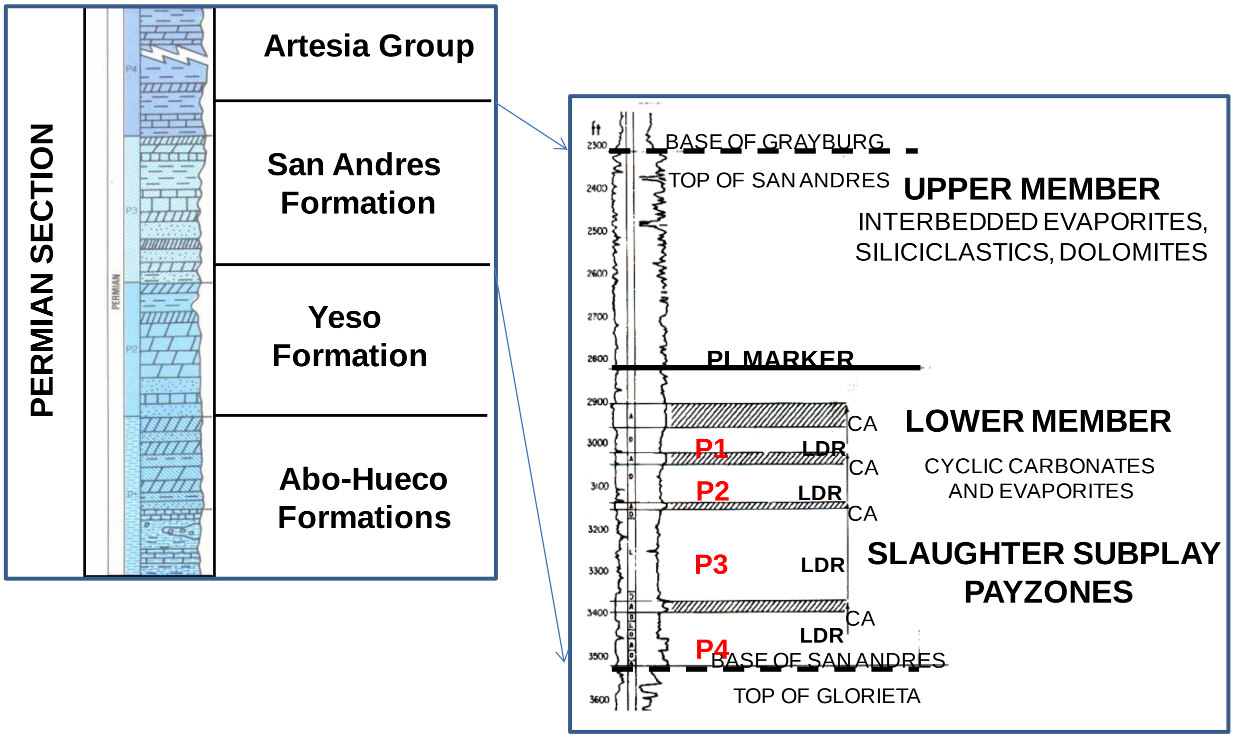


Figure 2. Stratigraphic column of San Andres in the Northwest shelf

Traps are commonly stratigraphic as a result of porosity zone pinchouts updip to the north or northwest. The cyclic nature of the regressive sequences has led to vertical stacking of porous zones (Figure 3); frequently separated by flow barriers. As a result, individual pay zones can act independently to the others.

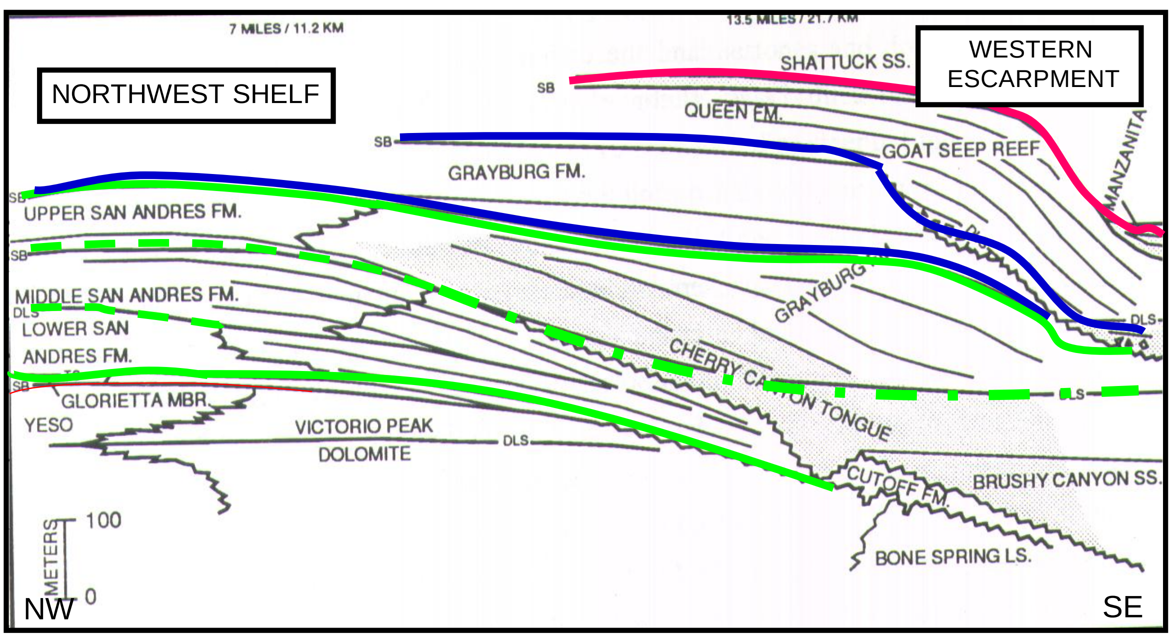


Figure 3. Cross section from the NW shelf to the western escarpment. (Sarg and Lehmann, 1986)

HISTORICAL DEVELOPMENT

Approximately 80 pools have produced 107 MMBO, 212 Bscf, and 317 MMBW from the Grayburg/San Andres play of the Northwest Shelf. Eight pools have contributed 81% of the cumulative oil in this play (Table 1); with Chaveroo the largest at 25MMBO through 2010. The play is mature, with first production in 1947 and peak production in 1968 (Figure 4).

poolName	Cum_Oil MMBO	percent of total	Cumulative %
CHAVEROO;SAN ANDRES	24.9	23%	23%
CATO;SAN ANDRES	16.5	15%	39%
MILNESAND;SAN ANDRES	12.4	12%	50%
FLYING M;SAN ANDRES	11.7	11%	61%
MESCALERO;SAN ANDRES	6.7	6%	68%
TWIN LAKE;SAN ANDRES	5.7	5%	73%
SAWYER WEST;SAN ANDRES	4.5	4%	77%
TOM TOM;SAN ANDRES	3.7	4%	81%

Table 1. Top ten cumulative oil pools in the Northwest Shelf (GB/SA) play. Source: digitized+dwights)

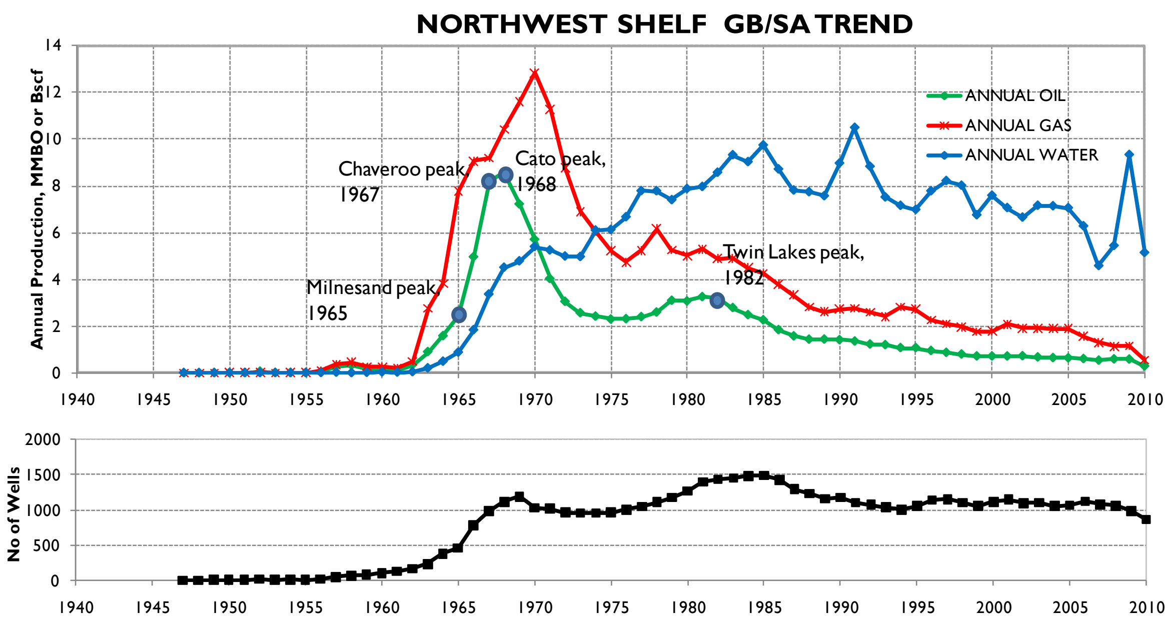


Figure 4. Annual production and well count for the Northwest shelf GB/SA play. (Source: digitized data+dwights)

Solution gas drive is the major production mechanism in reservoirs in the New Mexico part of the play. Subsequent rapid pressure depletion and low primary recovery lead to early waterflooding to improve oil recovery. All the pools in Table 1 have been waterflooded at some time in their history. As a result, the producing WOR for the play has been increasing (Figure 5) with a current value of 18 to 1 (95% watercut).

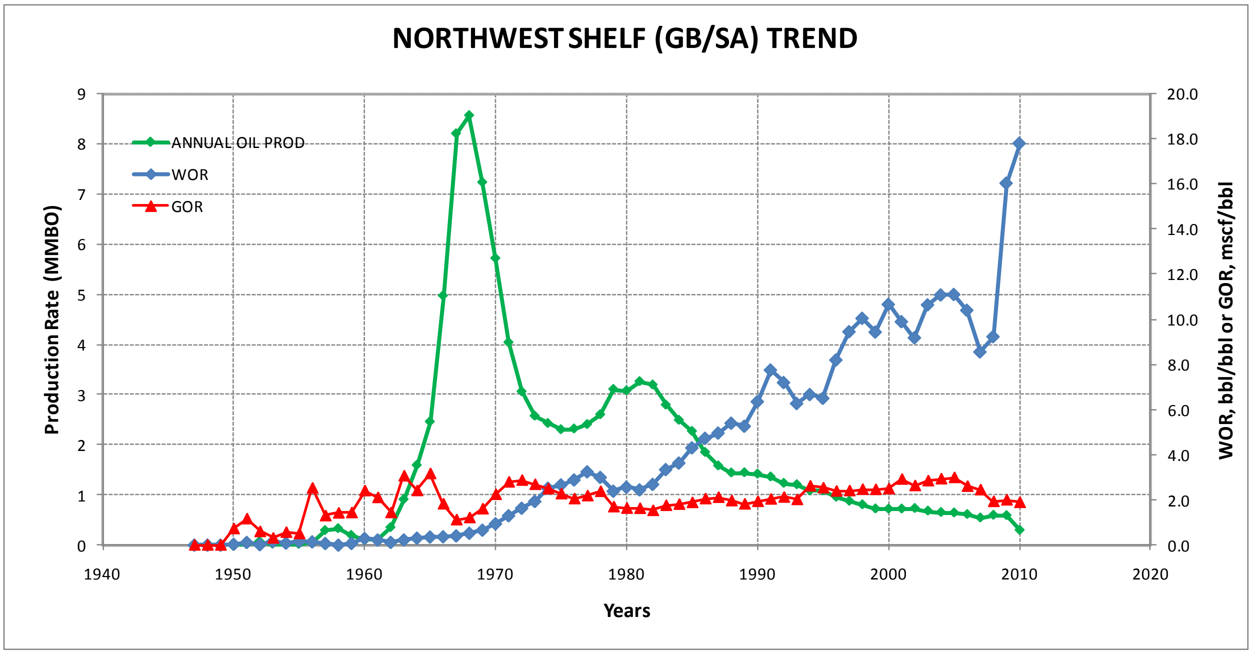


Figure 5. Annual oil production, WOR and GOR for the Northwest shelf GB/SA play. (Source: digitized data+dwights)

Top producing pools for 2010 are shown in Table 2. The three pools highlighted are not in the top cumulative producing pools listed in Table 1.

poolName	2010 oil rate BOPD	2010 WOR
FLYING M;SAN ANDRES	267	14.3
CATO;SAN ANDRES	208	45.0
ROUND TANK;SAN ANDRES	146	10.4
DIABLO;SAN ANDRES	89	1.2
CHAVEROO;SAN ANDRES	86	9.3
SAWYER;SAN ANDRES, WEST	72	10.9
MESCALERO;SAN ANDRES	64	6.5
SAUNDERS;SAN ANDRES	61	36.2

Table 2. Top producing oil pools for 2010 in the Northwest Shelf (GB/SA) play. Source: digitized+dwights)

Historical production curves for the Chaveroo San Andres Pool are shown in figure 6. This example is representative of the play; mature and nearing abandonment.

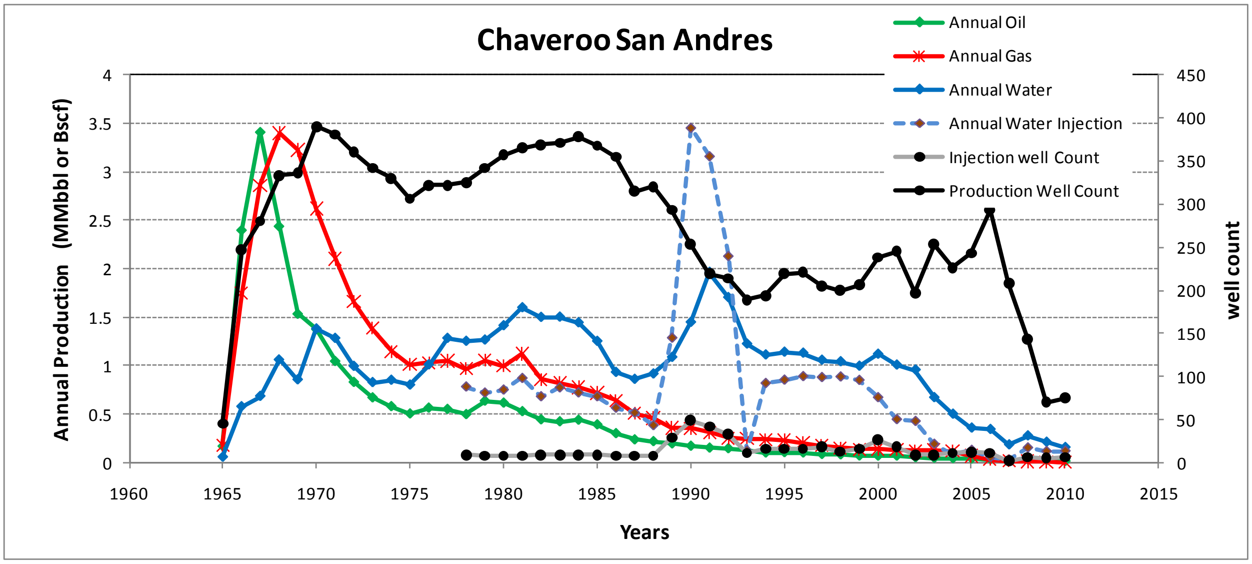


Figure 6. Annual production, injection and well count for the Chaveroo pool. (Source: digitized data+dwights)

Over the last seven years, 227 wells have been completed in this play (Figure 7), the majority, 55% (123) were drilled in the Cato Field. For Cato pool the performance (Fig 8) exhibits a minor increase in oil production in response to this development.

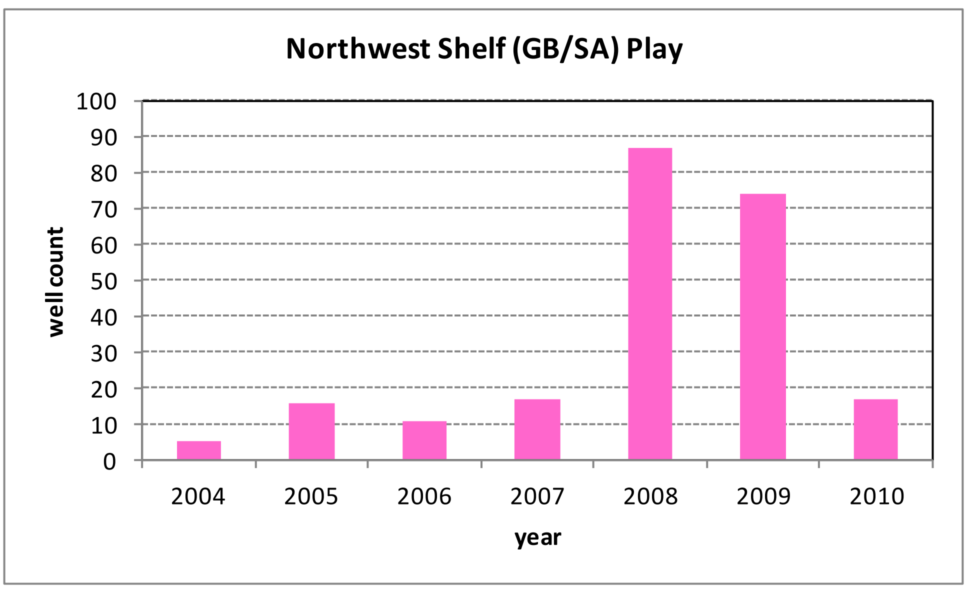


Figure 7. Recent well completions in the Northwest Shelf (GB/SA) play. (Source: GOTECH)

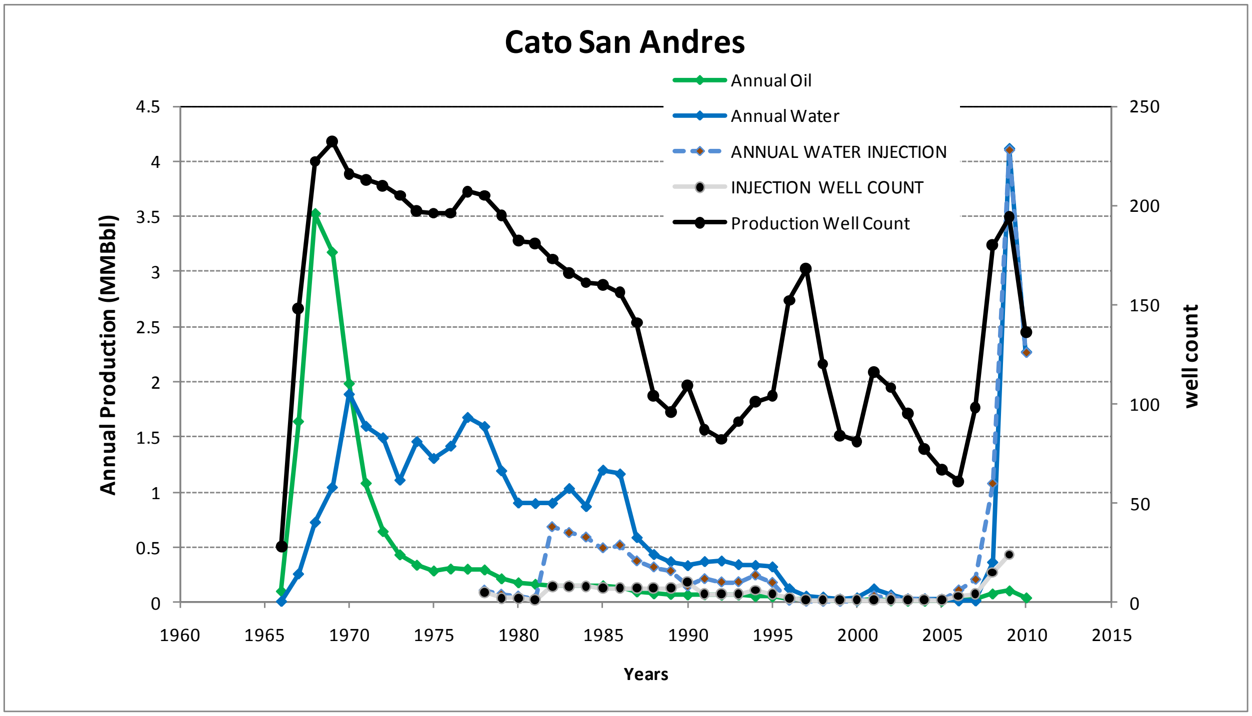


Figure 8. Annual production, injection and well count for the Cato pool. (Source: digitized data+dwights)

Predicted Development

The opportunities for future development are very limited. Reservoirs in this play are at a mature stage of development, close to abandonment. The majority of these pools have been waterflooded; with mixed results. Current WOR is very high; consequently leading to significant water handling and disposal issues.

Due to the poor performance of water flooding it is believed that the residual oil saturation will be high. Thus CO_2-EOR potential exists to recover a high percentage of the remaining oil in both the main pay zone and the residual oil zone. Furthermore, the proximity of major CO_2 pipelines provides a potential source of CO_2 for this tertiary recovery.

The operator of the Milnesand pool initiated a pilot CO_2 project in December 2008. The CO2 was hauled in by truck from Eastern Arizona/Western New Mexico. A five-spot pattern was developed with two WAG injectors shown in red in Figure 9. Carbon dioxide was injected for eight months, followed by water injection. Performance was poor and not encouraging (Figure 10).

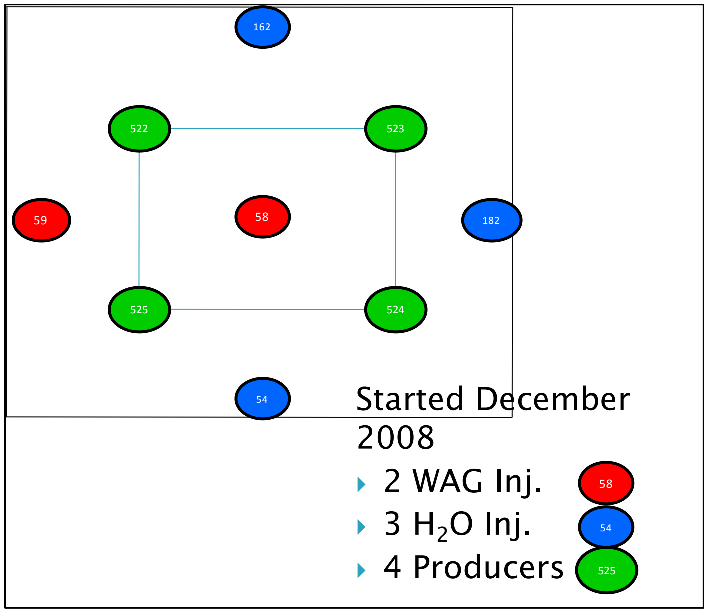


Figure 9. Schematic of the CO2 injection pilot in the Milnesand pool.

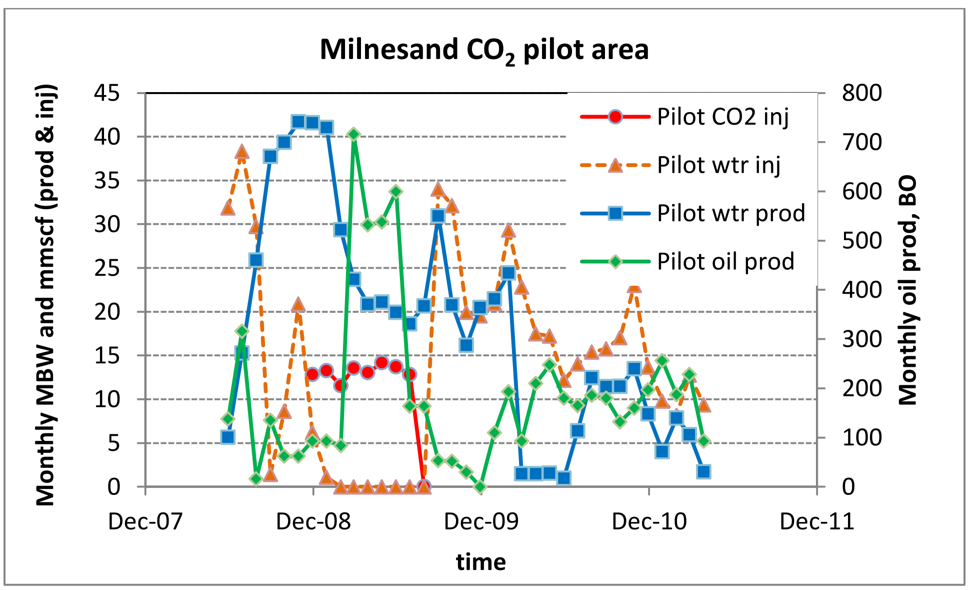


Figure 10. Monthly injection and production for the Milnesand Pilot area. (Data Source: GOTECH)

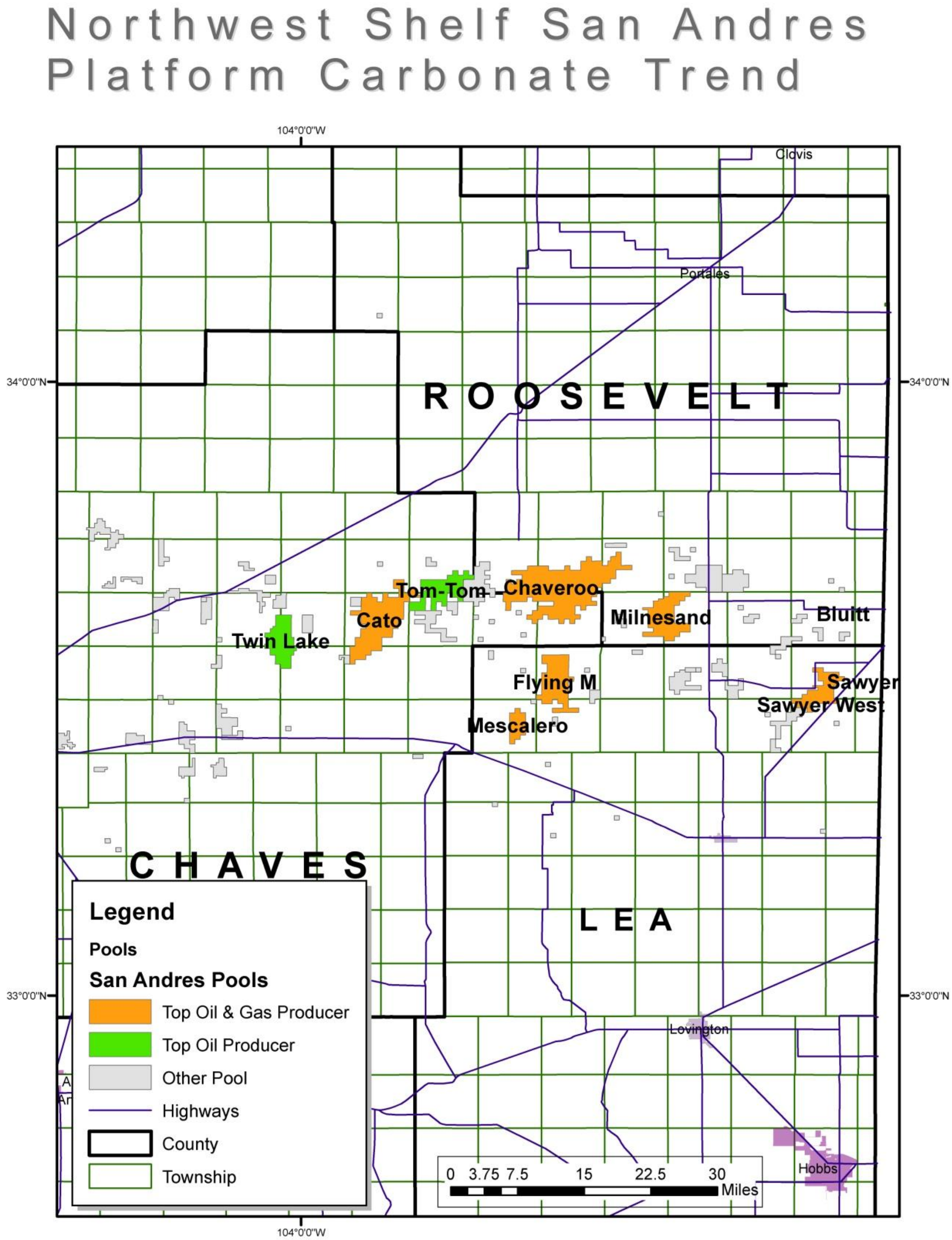


Figure 11. Pool map for the northwest Shelf San Andres Platform Carbonate Play.

Simpson Cratonic Sandstone Play

The potential for future development is ***very low***.

Brief Summary of Geology

The Middle to Upper Ordovician Simpson Group is a thick carbonate and clastic succession present in two distinct depocenters; one in West Texas and southeastern New Mexico and a second in southern Oklahoma (Jones, 2007). In New Mexico, maximum thickness is about 1000 ft in southeastern Lea County (Broadhead, et al, 2004). The unit thins to the west, north, and east, and is absent in Roosevelt County, New Mexico, and Cochran, Terry, Dawson, Howard, Glasscock, and Reagan Counties, Texas (Jones, 2007).

The Simpson Group is comprised of five formations (Figure 1): Joins Formation, Oil Creek Formation, McLish Formation, Tulip Creek Formation, and Bromide Formation. Production comes from three quartz rich sandstone intervals ranging from 20 to 50 ft thick, found within the Oil Creek, McLish, and Tulip Creek Formation. The productive sandstones (Connell, Waddell, and McKee) occur as basal sandstones at the base of these formations, respectively. Productive sandstones are separated by nonreservoir intervals composed of mostly green shales (Galley, 1958). The intervening organic-carbon-rich Simpson shales are significant because they are the likely source of the Ordovician oil found in many Central Basin Platform area reservoirs, including the Lower Ordovician Ellenburger (Jones, 2007). The overlying and underlying Bromide and Joins Formations are both carbonate units. The Simpson Group is also significant because it overlies a major hiatus in the Lower Ordovician and records a unique Middle Ordovician depositional environment in which both clastics and carbonates were deposited during a period of overall sea-level rise.

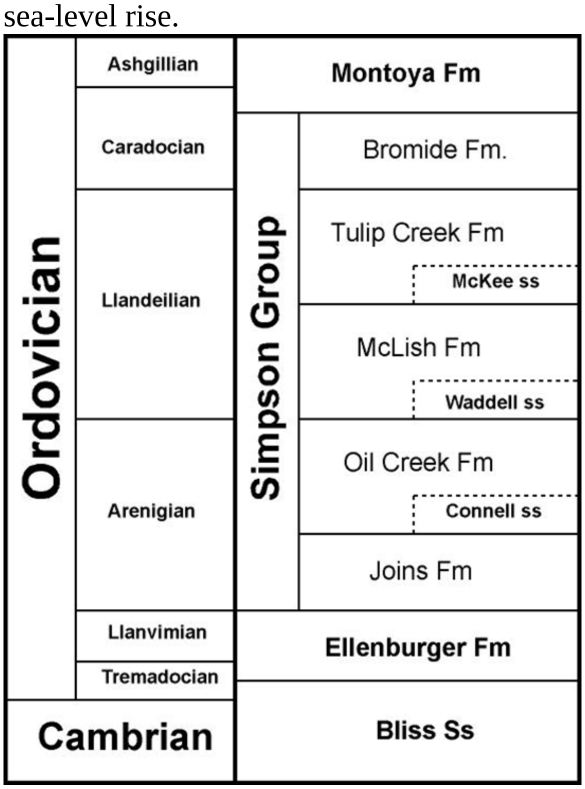


Figure 1. Stratigraphic section of the Simpson Group in Southeast New Mexico

Simpson Group sandstones are exceptionally clean, however carbonate cementation may be locally common and can reduce reservoir quality. The Transcontinental Arch and the Pedernal uplift have been suggested as sediment supplies for the clean quartz sand of the Simpson group (Jones, 2007). Traps for the Simpson are typically structural, occuring on anticlines, in folded and faulted structures on anticline flanks, or where Simpson Group sandstones are truncated by erosion on flanks of anticlines. Seals are either overlying Simpson shales, or post-Simpson rocks, depending on the reservoir (Jones, 2007). There are few purely stratigraphic traps documented in Simpson reservoirs, and these are in Crane and Pecos Counties of Texas.

HISTORICAL DEVELOPMENT

The Simpson pools are limited to the central basin platform in Lea County, New Mexico (Figure 2). Cumulative oil production has been slightly less than 45 MMBO through 2010. Initial discovery was in 1948 from the Hare (Simpson) Pool. A total of 15 pools have produced from the Simpson, with the top five pools (Warren, Hare, Teague, Justis and Justis, North) comprising 98% of the total oil produced.

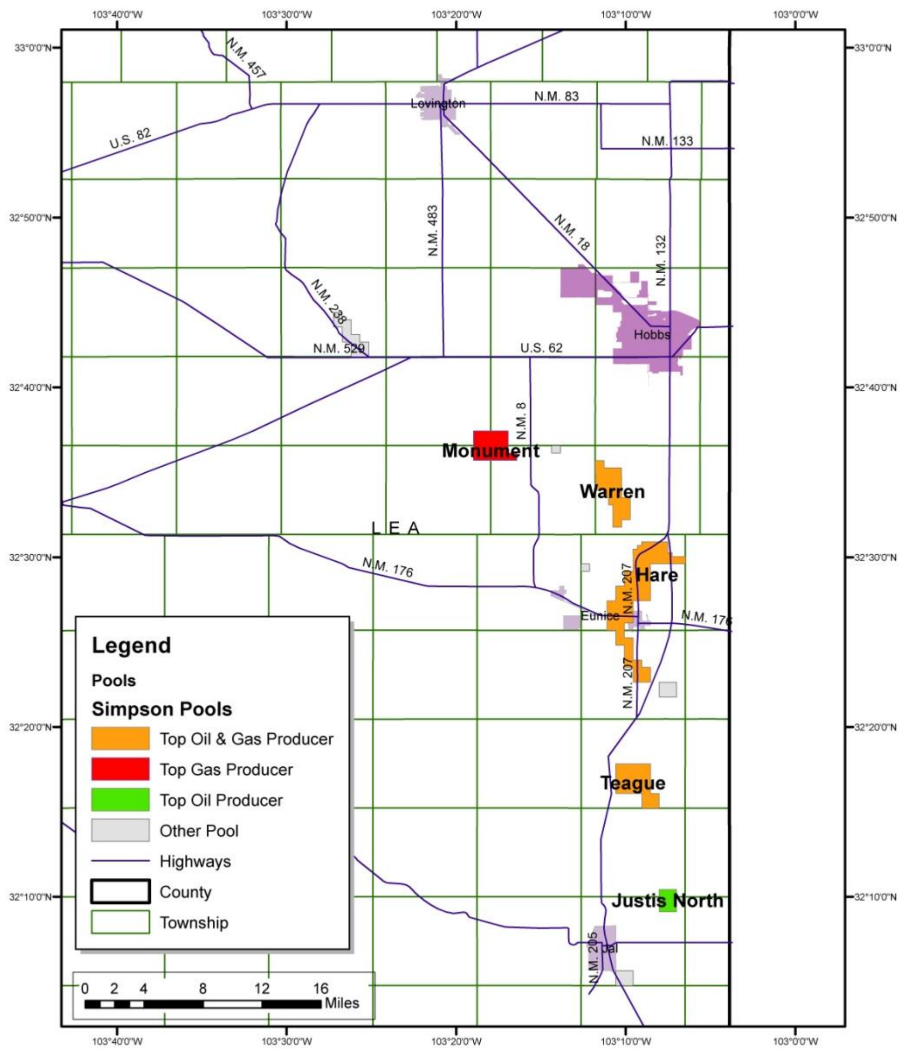


Figure 2. Play boundary and location of major oil reservoirs for the Simpson play.

The play is well-established; exhibiting a declining trend in oil production with time (figure 3). Peak production was in 1953 where the play averaged 9,970 BOPD for the year. For 2010 production averaged 373 bopd.

The major drive mechanism is solution gas, with occasional water drive noted in some pools. Cumulative water production has been 31 MMBW through 2010. No pool has excessive water cut or watered out due to encroaching water. However, since the trapping is typically structurally controlled, downdip water is typically encountered. Cumulative gas production has been 139 Bscf; the majority is associated gas; however, several pools are categorized as gas pools.

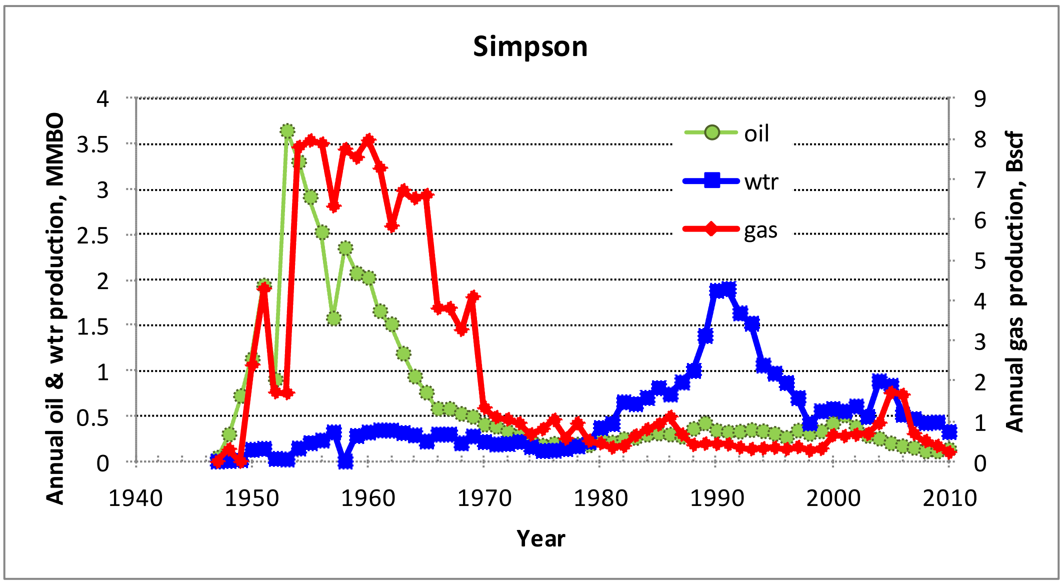


Figure 3. Simpson play annual oil production. (Source: digitized data+ Dwights).

Two pools; Warren and Teague, have been waterflooded. Success of the waterflood in the Warren is marginal. In the Teague, new wells drilled along with water injection re-established production from the McKee sandstone (Figure 4) and resulted in the production increase seen in 2000 in Figure 3.

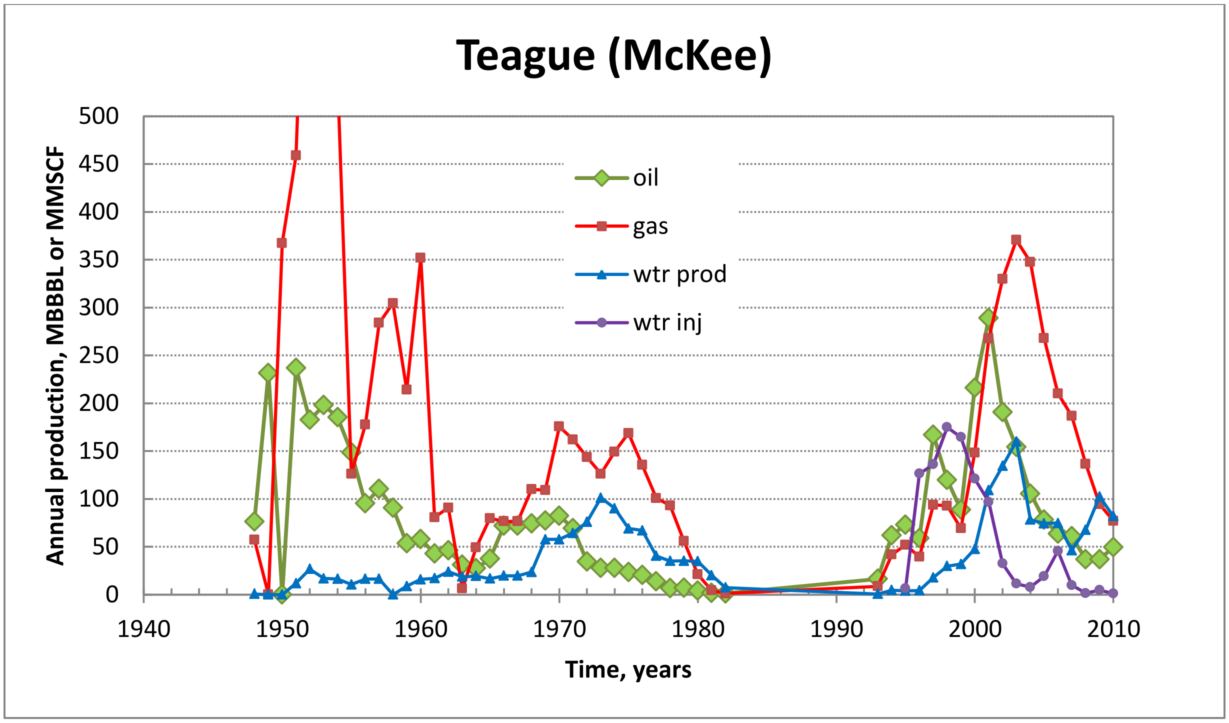


Figure 4. Annual production and injection for the Teague (McKee) Pool
(Data Source: digitized + Dwights)

FUTURE DEVELOPMENT

Limitations

The limiting factors in further developing the Simpson sands are:

1. Areally confined to the central basin platform; thus does not have widespread potential
2. Only 60 wells active in the entire play in several old, well-established pools. Six wells have been completed in the Simpson since 2004.
3. With regards to most other oil and gas plays the Simpson is a deep target, thus not considered an uphole potential zone
4. As old wells, potential well integrity problems limit their usefulness

Potential improvement

The Hare (Simpson) pool has been screened as amenable to CO_2-EOR (ARI, Feb 2006); however, for the reasons cited above and the availability of significant better targets for CO_2 recovery it is unlikely the Simpson will undergo EOR any time soon.

Improvement through development (infill, extensions) has been demonstrated as feasible in the Teague Field. Duplication may be possible in other fields, but was not considered as having a high impact.

Wolfcamp Carbonate Plays

BRIEF SUMMARY OF GEOLOGY

Broadhead ,et al, (2004) divide the Wolfcamp into two major plays: the Wolfcamp Platform Carbonate play and the Wolfcamp/Leonard Slope and Basinal Carbonate play. The Wolfcamp Platform Carbonate play includes those reservoirs deposited on the shelf and shelf margin of the northern Delaware Basin. The Wolfcamp/Leonard Slope and Basinal Carbonate play includes reservoirs deposited basinward of the shelf margin. In this work, we will combine the Wolfcamp from both plays and the gas pools into one group (see Figure 1). A detailed discussion on the geology of the Wolfcamp can be found in Broadhead, et al. 2004.

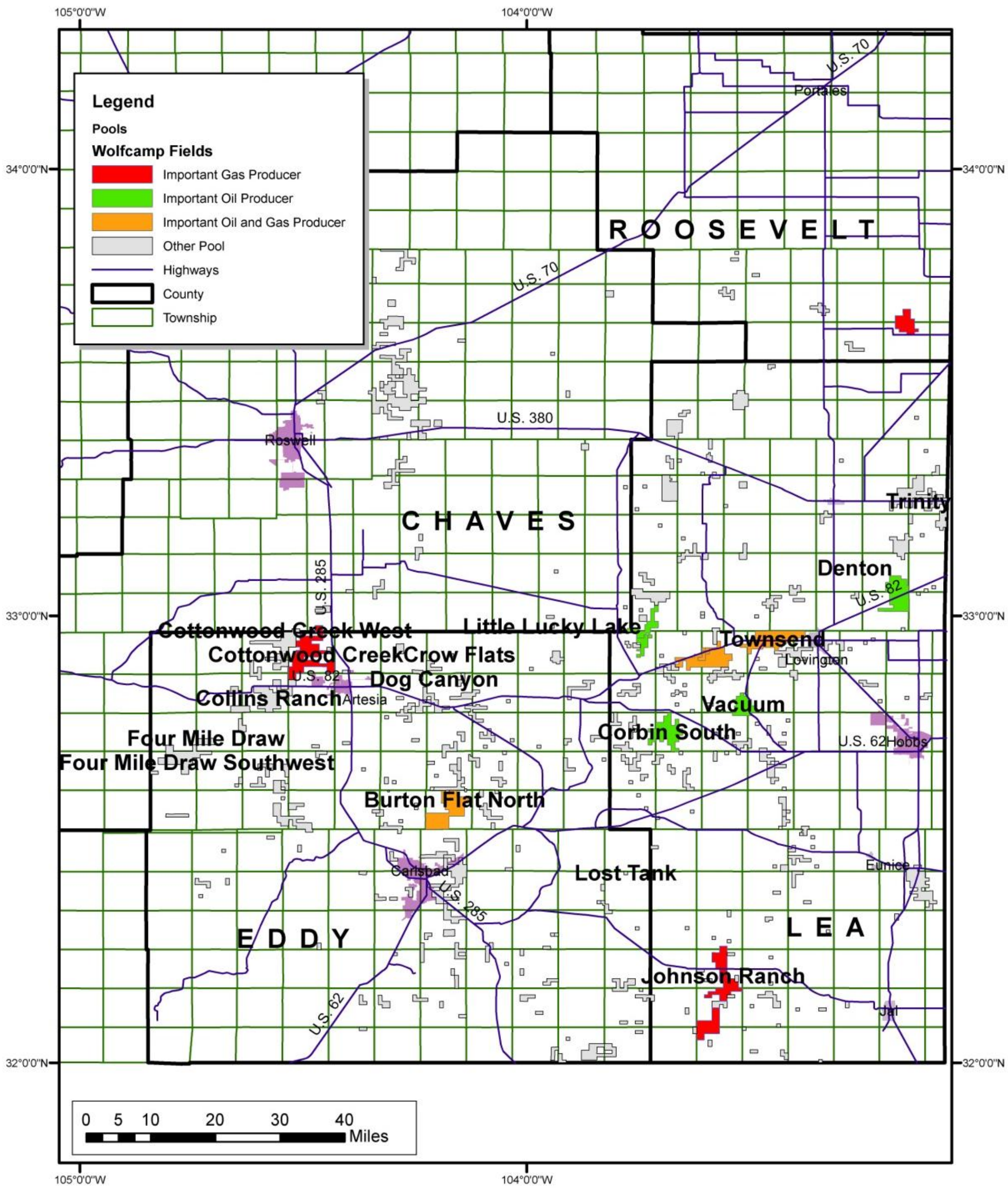


Figure 1. Pool map for the Wolfcamp

Depths to reservoirs range from 7580 to 10,750 ft. for the Wolfcamp Platform Carbonates. Traps on the shelf are largely stratigraphic, with porosity pinchouts. On the shelf margin, traps are combinations of structural high areas and stratigraphic pinchouts. It is common to find Wolfcamp reservoirs stacked atop structurally controlled reservoirs in older, deeper strata.

Traps for the Wolfcamp/Leonard Slope and Basinal Carbonate Play are largely stratigraphic, with reservoirs bounded by kerogen-rich basinal shales which act as both the seal and the source rock. Production is largely derived from limestones in the lower Wolfcamp occuring at depths from 9160 to 13,500 ft.

HISTORICAL DEVELOPMENT

Approximately 300 pools are reported to have produced from the Wolfcamp in Southeast New Mexico. Initial production was in 1950 (Figure 2) from the Denton Pool in Lea County. Through 2010 cumulative production has been 172 MMBO, 832 BCF gas, and 266 MMBW. Peak production for some of the top oil pools is indicated in Figure 2. Table 1 lists the top eight oil pools, accounting for 64% of the total play's oil production. Table 2 shows the top 11 producing pools for 2010.

poolName	Cum_Oil MMBO	percent of total	Cumulative %
DENTON;WOLFCAMP	41.9	24%	24%
TOWNSEND;WOLFCAMP	22.5	13%	37%
KEMNITZ;WOLFCAMP	16.6	10%	47%
CORBIN SOUTH;WOLFCAMP	7.3	4%	51%
VACUUM;WOLFCAMP	6.7	4%	55%
ANDERSON RANCH NORTH;WOLFCAMP	6.0	3%	59%
ANDERSON RANCH;WOLFCAMP	4.8	3%	61%
BURTON FLAT NORTH;WOLFCAMP	4.1	2%	64%

Table 1. Top pools by cumulative oil production. (Source: digitized+dwights)

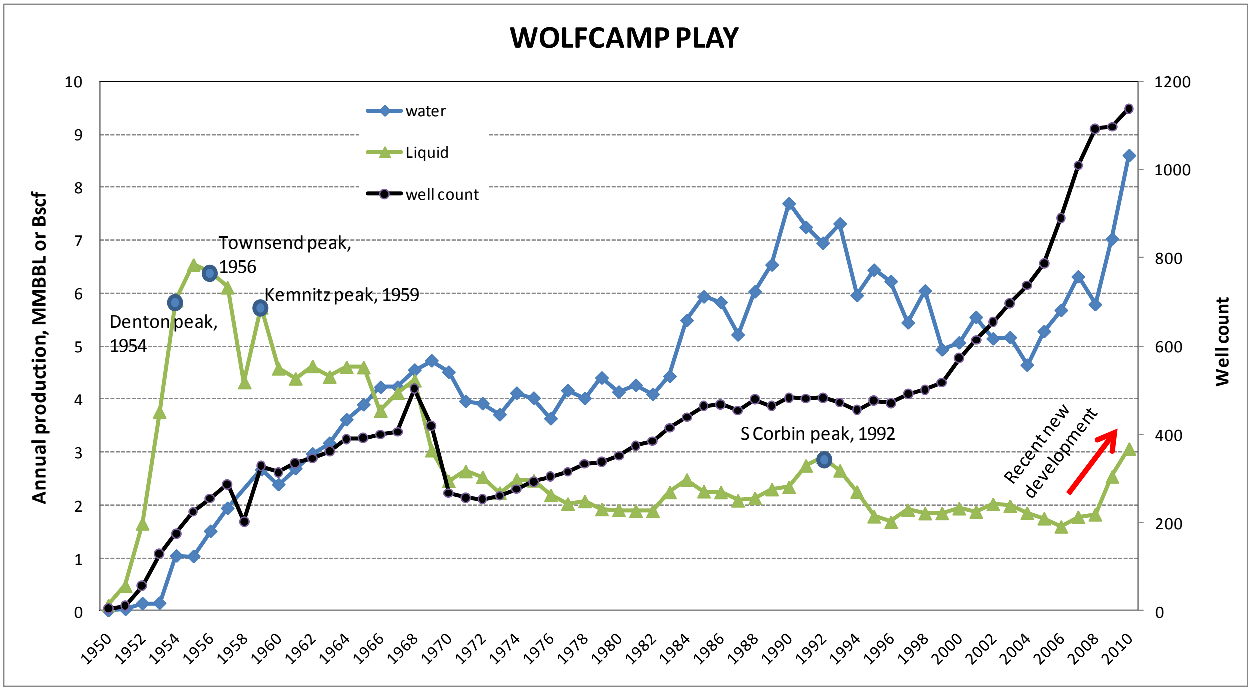


Figure 2. Annual oil and water production, and well count for Wolfcamp play. (Data Source: Digitized + Dwights)

Pools highlighted in gray are not in the top cumulative production list in Table 1. Unlike many other plays, the majority of top 2010 Wolfcamp oil producing pools are not top cumulative producing pools; implying recent new development has been successful.

poolName	2010 oil rate BOPD	horizontal wells
DOG CANYON;WOLFCAMP	1652	18
DENTON;WOLFCAMP	824	11
CROW FLATS; WOLFCAMP	745	10
LITTLE LUCKY LAKE;WOLFCAMP	398	3
TRINITY;WOLFCAMP	362	
LOST TANK; WOLFCAMP	201	
TOWNSEND;PERMO UPPER PENN	198	
CORBIN;WOLFCAMP, SOUTH	153	2
BRONCO;WOLFCAMP	128	1
VACUUM;WOLFCAMP	111	
BURTON FLAT; WOLFCAMP, NORTH (GAS	102	2

Table 2. Top pools by 2010 oil production rate. (Source: digitized+dwights)

Pool performance for the top six pools highlighted in gray in Table 2 is shown in Figure 3. Well count has increased from zero in 2001 to almost 70 by 2010. As a result the oil production has been on an incline to over 1.2 MMBO produced in 2010 from these pools alone.

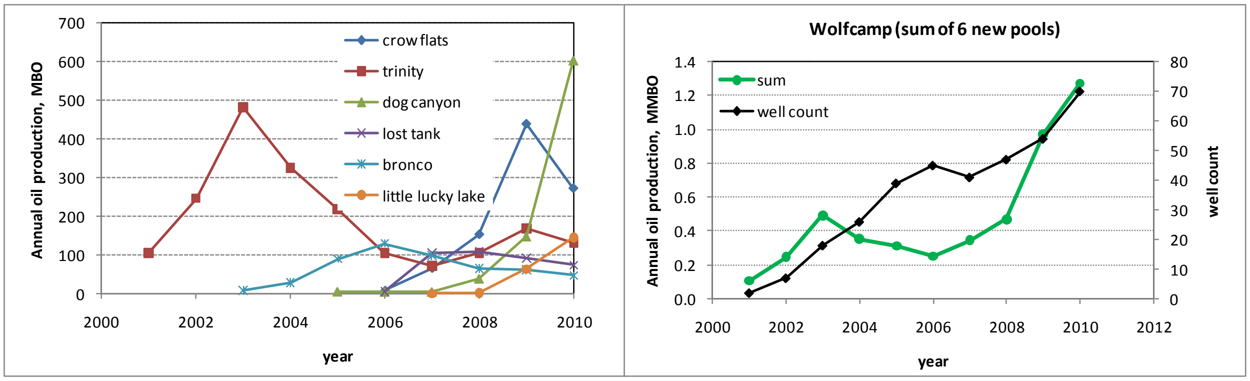


Figure 3. (a) Top six recent oil production pools, (b) Sum of the six pools and well count (Data Source: GOTECH)

Since this play also produces significant gas, a similar analysis is provided for gas as well. Figure 4 is the performance curves for all of the Wolfcamp with selected top cumulative producing gas pools indicated on the plot. Table 3 lists the top seven gas pools, accounting for 38% of the total play's gas production. Table 4 shows the top 10 gas producing pools for 2010.

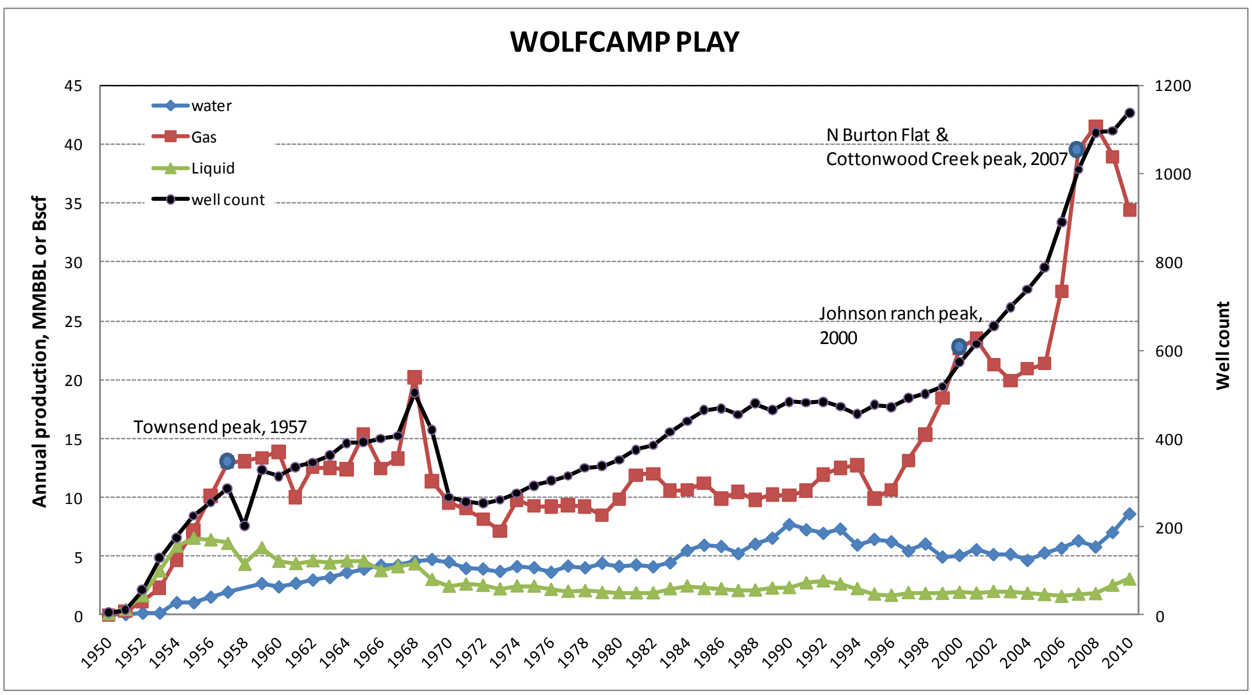


Figure 4. Annual oil, water and gas production, and well count for Wolfcamp play. (Data Source: Digitized + Dwights)

poolName	Cum_gas Bscf	percent of total	Cumulative %
TOWNSEND;WOLFCAMP	61.5	7%	7%
JOHNSON RANCH;WOLFCAMP	53.4	6%	13%
KEMNITZ;WOLFCAMP	53.2	6%	20%
BLUITT;WOLFCAMP	43.0	5%	25%
RED HILLS;WOLFCAMP	40.7	5%	30%
BURTON FLAT NORTH;WOLFCAMP	39.3	5%	34%
COTTONWOOD CREEK;WOLFCAMP	33.3	4%	38%

Table 3. Top pools by cumulative gas production. (Source: digitized+dwights)

poolName	2010 gas rate MCFD	horizontal wells
COTTONWOOD CREEK;WOLFCAMP (GAS)	13147	55
COTTONWOOD CREEK;WC, WEST (GAS)	6931	44
WALNUT CREEK; WOLFCAMP (G)	5227	17
COLLINS RANCH;WOLFCAMP (GAS)	4578	19
FOUR MILE DRAW; WOLFCAMP(G)	4055	15
BURTON FLAT; WOLFCAMP, NORTH (GAS)	3653	2
JOHNSON RANCH;WOLFCAMP (GAS)	3048	1
CROW FLATS; WOLFCAMP	2880	10
LOST TANK; WOLFCAMP	2418	
FOUR MILE DRAW; WOLFCAMP, SW (G)	2352	20

Table 4. Top pools by 2010 gas production rate. (Source: digitized+dwights)

Again, the majority of top gas producing pools for 2010 are not top cumulative producing pools listed in Table 3. This recent success has had a profound effect on Wolfcamp development. Shown in Figure 5 is the performance of these recent discoveries. Slightly greater than 200 wells have been drilled since 2003 resulting in a peak rate of 24 Bcf in 2009 or 60 % of the total play.

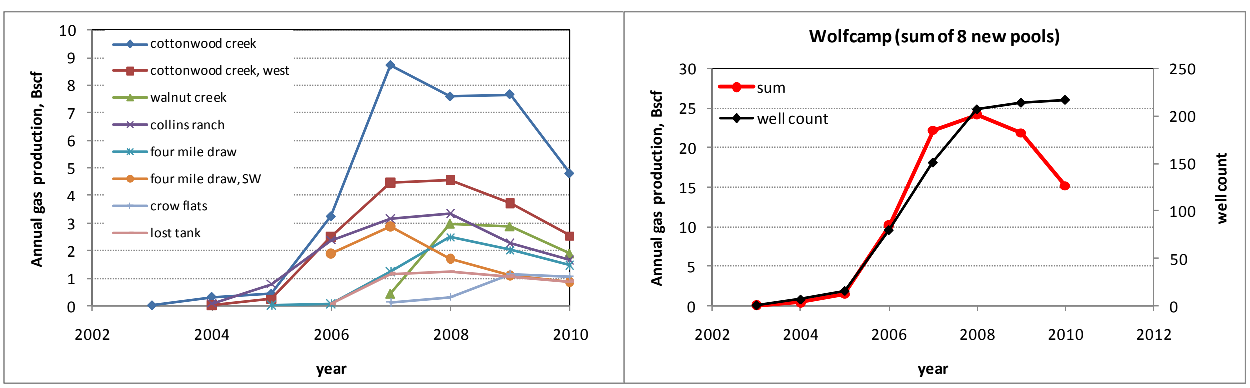


Figure 5. (a) Top eight recent gas production pools, (b) Sum of the eight pools and well count (Data Source: GOTECH)

Contributing to this recent success has been the use of horizontal wells in developing the reservoir; from three horizontal wells drilled in 2005 to 67 drilled in 2006 (Figure 6). In the early years (2006-2008), the majority of horizontal wells were drilled for gas; with the greatest activity observed in the Cottonwood Creek area (see Table 4). Recently (2009-2010), the horizontal well activity has declined and has focused on oil targets instead of gas. Horizontal wells for oil pools are listed in Table 2. The change from gas to oil development is a reflection in the change in commodity price and is demonstrated in Figure 7 for the entire play.

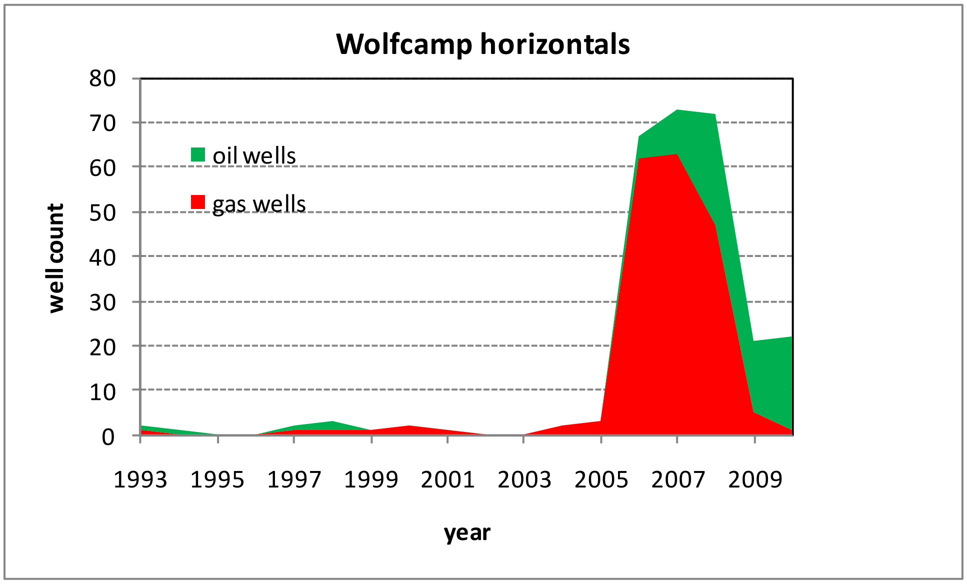


Figure 6. Wolfcamp horizontal well count separated by gas or oil target. (Data source: Dwights)

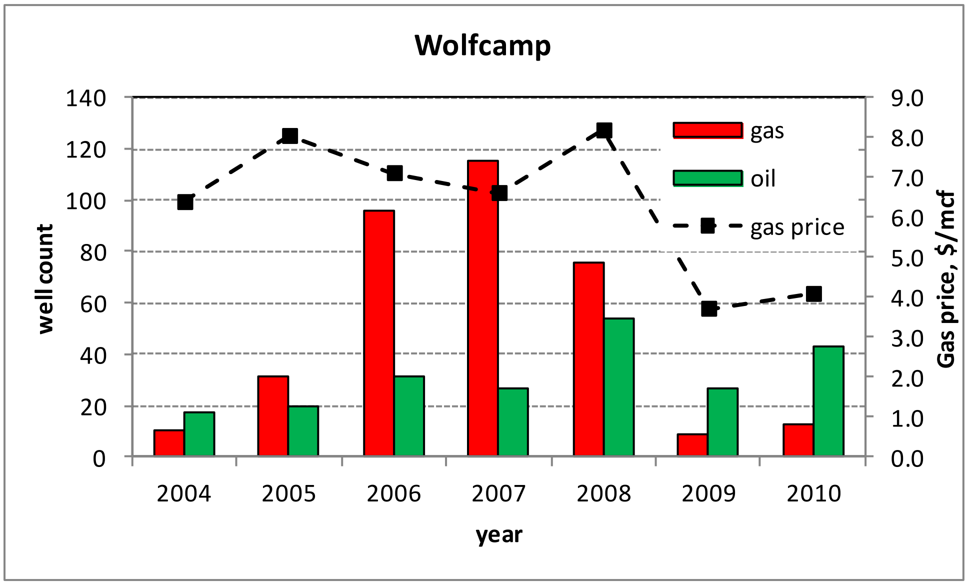


Figure 7. Comparison of recent (2004-2010) well activity separate by oil or gas with the gas price. (Data source: well counts from GOTECH, price from EIA)

Seven wolfcamp pools have had some level of water injection. Only one, the Denton (Wolfcamp) has injected significant volumes of water, accounting for 76% of the total injection for this play; however no discernable response was observed. Explanations for this poor response are: (1) injection is only half of the total withdrawal rate and thus is not sufficient to maintain pressure, (2) heterogeneous reservoir reducing sweep efficiency, and/or (3) an existing water drive that had previously swept the oil volume. For these reasons, additional waterflood development is unlikely, and is instead considered a water disposal project.

PREDICTED DEVELOPMENT

Even though recent gas development has been successful, low predicted gas prices will likely suppress future development. As seen in Figure 7, oil development has doubled over the last seven years to ~ 40 per year and it is expected this trend will continue to grow. However, the limited extent and heterogeneity of these pools will reduce the overall impact. Potentia map is shown in Figure 8.

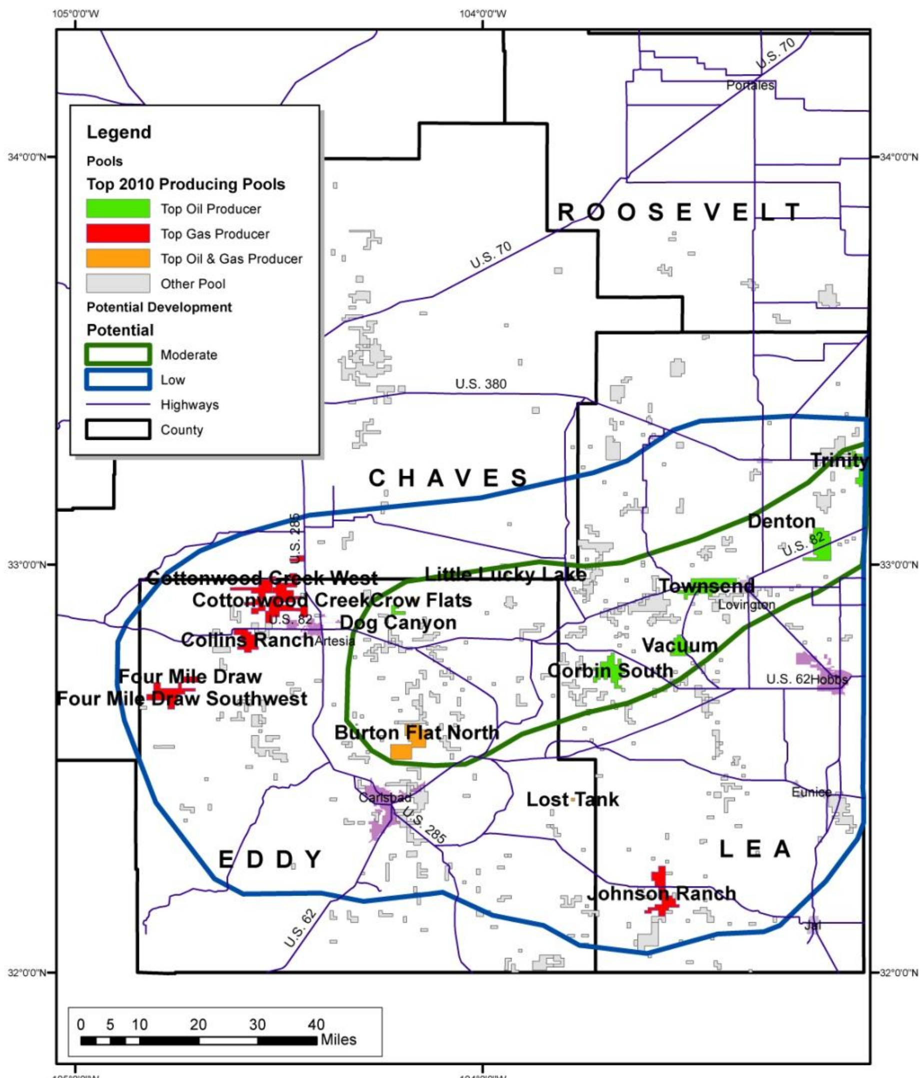


Figure 8. Potential map for the Wolfcamp Play. Green line – moderate, blue line – low potential

Wristen Buildups and Platform Carbonate Play

Brief Summary of Geology

Commonly known as Devonian, Silurian or Siluro-Devonian, the correct geologic name is the Wristen Group (Broadhead, et al, 2004). Recent work has demonstrated almost all of the dolomitic carbonates present in southeast New Mexico above the Fusselman Formation and below the Woodford Shale belong to the Wristen Group (Figure 1). South (basinward) of the shelf margin the Wristen consists of two deeper water carbonates, the Wink, a lower, gray, nodular limestone mudstone to wackestone unit and the Frame, an upper shaley to argillaceous lime mudstone and wackestone unit. North of shelf margin (shelfward) the Wristen group is called Fasken, a shallow water carbonate.

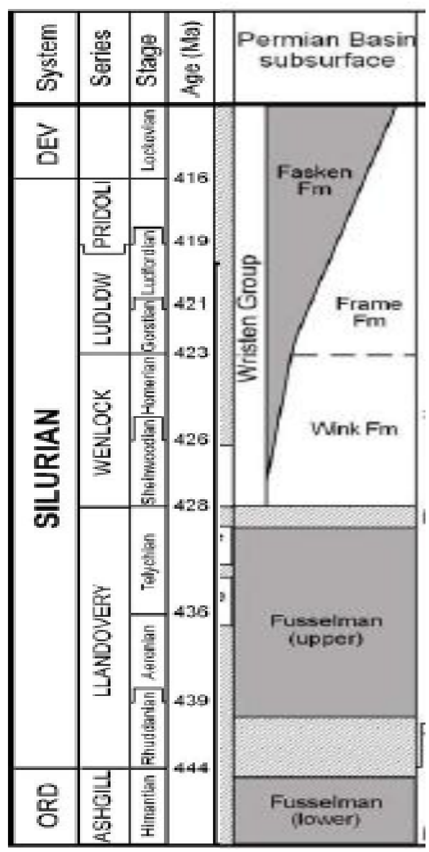


Figure 1. Stratigraphic column for Wristen Group (Ruppel)

The Wristen is approximately 1400 feet thick in southeastern Lea County, New Mexico and thins to the west as it is erosionally truncated under the pre-Woodford unconformity. The zero-thickness line trends generally northeast-southwest (shown in Figure 2), with productive pools to the east of this demarcation line in the thicker section.

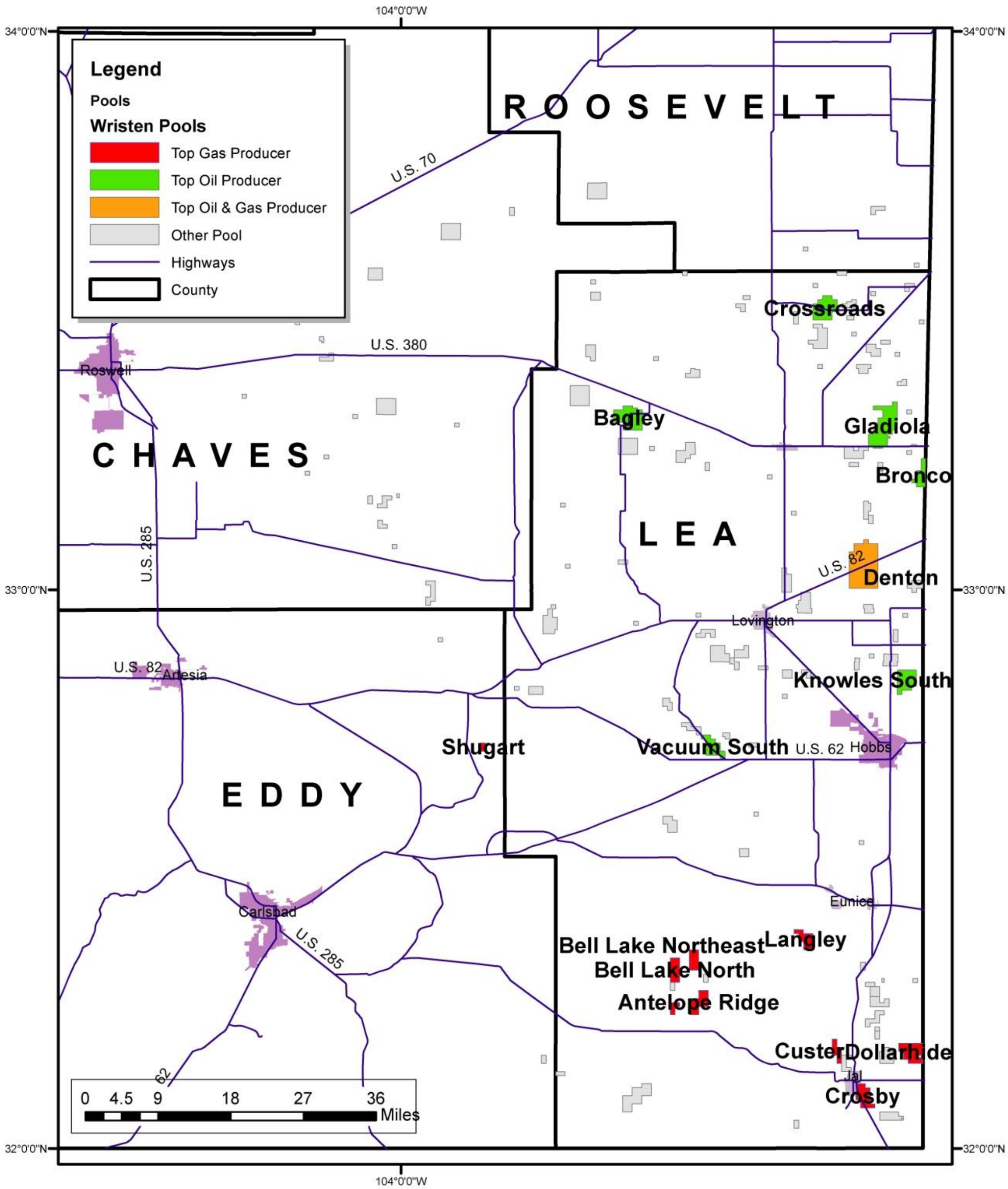


Figure 2. Pool map for Wristen Buildups and Platform Carbonate Play

Porosity is a mix of both primary and secondary development. Present are moldic, vugular, karstic (including collapse breccia) and intercrystalline, as well as intergranular along the shelf margins. Where it is present, the overlying Woodford Shale acts as both source and seal. Traps are dominantly structural.

HISTORICAL DEVELOPMENT

The majority of reservoirs in this mature play were discovered in the late 1940's through 1960 (Figure 1); with peak production in 1957 of 67 MBOPD. Many of these older reservoirs were in decline prior to 1980. In general, production peaks within a few years of discovery followed by a sharp decline. This behavior is due to the active water drive found in most Wristen reservoirs, which provides sufficient energy to support high production rates until water coning and breakthrough results in abandoning the well (Figure 1).

Table 1 lists the top cumulative oil producing pools. Approximately 100 pools have produced 431 MMBO, 54 Bscf, and 2,300 MMBW from this play, with the top ten pools contributing 74% of the total play production.

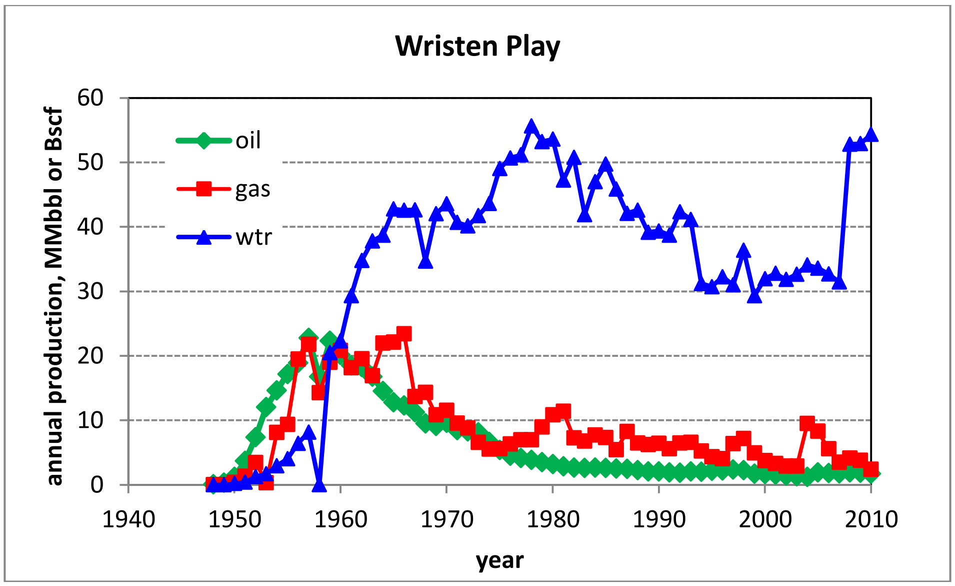


Figure 1. Annual oil, gas and water production for the Wristen play. (Data Source: Digitized + Dwights)

poolName	Cum_Oil MMBO	percent of total	Cumulative %	Peak year
DENTON;DEVONIAN	100.6	25%	25%	1955
GLADIOLA;DEVONIAN	53.4	13%	38%	1958
CROSSROADS;SILURO / DEVONIAN	44.0	11%	49%	1973
BAGLEY;SILURO / DEVONIAN	30.0	7%	56%	1952
MOORE;DEVONIAN	21.7	5%	61%	1956
BRONCO;SILURO / DEVONIAN	16.8	4%	65%	1956
KNOWLES SOUTH;DEVONIAN	10.2	3%	68%	1957
DOLLARHIDE;DEVONIAN	9.9	2%	70%	1973
VACUUM SOUTH;DEVONIAN	9.1	2%	73%	1961
ANDERSON RANCH;DEVONIAN	8.8	2%	75%	1953

Table 1. Top pools by cumulative oil production through 2010. (Source: digitized+dwights)

Table 2 lists the top oil producing pools in 2010. Also, shown in Table 2 is the 2010 producing WOR. Other than a few exceptions, the WOR is high due to the mature age of these pools and the active water drive mentioned previously.

poolName	2010 oil rate BOPD	2010 WOR
DENTON;DEVONIAN	1625	24
BAGLEY;SILURO / DEVONIAN	399	53
CROSSROADS;SILURO / DEVONIAN	372	16
WILDCAT;DEVONIAN	272	4
KNOWLES SOUTH;DEVONIAN	233	42
GLADIOLA;DEVONIAN	206	97
DOLLARHIDE;DEVONIAN	185	4
BRONCO;SILURO / DEVONIAN	183	51
VACUUM SOUTH;DEVONIAN	124	91
SAWYER;DEVONIAN	96	2

Table 2. Top pools by 2010 oil production rate. (Source: digitized+dwights)

The Denton (Devonian) pool is the most dominant pool in this play; producing 100 MMBO or 23% of the total play production, and the largest oil producer in 2010 at 1,625 BOPD. The performance curve for this pool (Fig. 3) exhibits the classic water drive behavior; e.g., increasing WOR and constant GOR with time. This behavior was observed in the majority of Devonian pools.

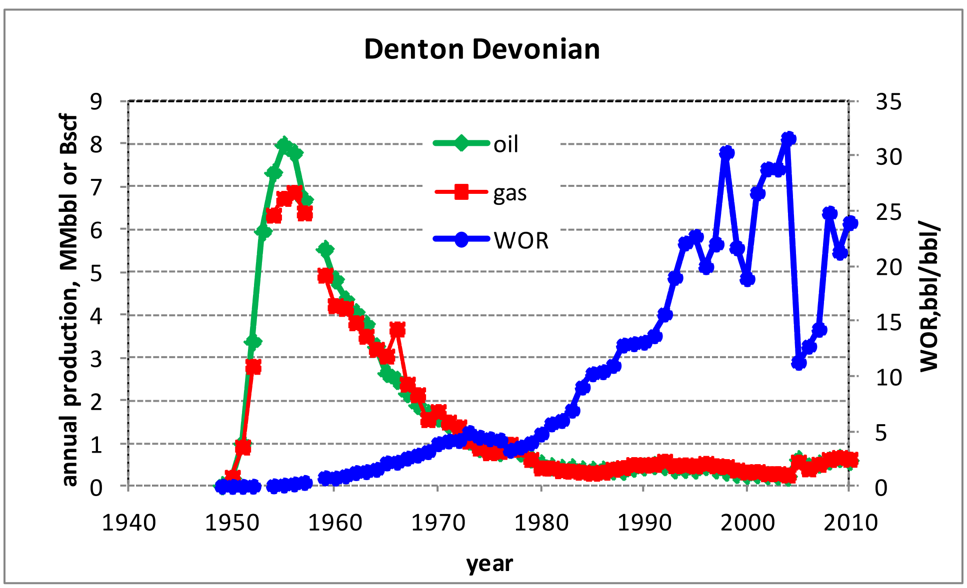


Figure 3. Annual oil, gas production and WOR for the Denton (Devonian) pool. (Data Source: Digitized + Dwights)

The top ten gas cumulative gas producing pools is listed in Table 3. The majority is associated gas with oil such as Denton; however, several Devonian pools produce free gas with little water production. An example is the Crosby (Devonian) pool shown in Figure 4.

poolName	Cum_Gas Bscf	percent of total	Cumulative %
CROSBY;DEVONIAN	95.4	18%	18%
DENTON;DEVONIAN	91.5	17%	35%
CUSTER;DEVONIAN	54.4	10%	45%
ANTELOPE RIDGE;DEVONIAN	39.0	7%	52%
BELL LAKE NORTH;DEVONIAN	30.3	6%	57%
SHUGART;SILURO / DEVONIAN	20.9	4%	61%
BELL LAKE NORTHEAST;DEVONIAN	19.8	4%	65%
BELL LAKE;DEVONIAN	18.2	3%	68%
DOLLARHIDE;DEVONIAN	17.7	3%	72%
LANGLEY;DEVONIAN	14.3	3%	74%

Table 3. Top pools by cumulative gas production through 2010. (Source: digitized+dwights)

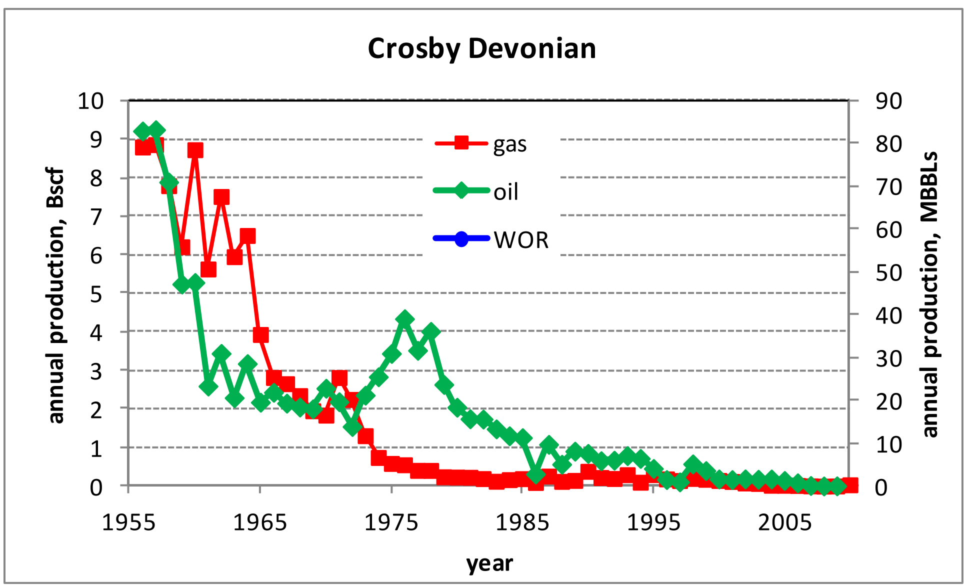


Figure 4. Annual oil, gas production and WOR for the Crosby (Devonian) pool. Note scale change for oil production. (Data Source: Digitized + Dwights)

Top 2010 gas producing pools are listed in Table 4. Northeast Bell Lake is a recent (2003) extension to the Bell Lake area and thus is producing at the second highest gas rate for 2010. This pool also produces significant quantities of water.

poolName	2010 gas rate MCFD
DENTON;DEVONIAN	1738
BELL LAKE NORTHEAST;DEVONIAN	1119
PADUCA NORTHWEST;DEVONIAN	517
BELL LAKE NORTH;DEVONIAN	481
LANGLEY;DEVONIAN	432
BLUITT NORTH;SILURO / DEVONIAN	381
CUSTER;DEVONIAN	370
ANTELOPE RIDGE NORTH;DEVONIAN	203
KNOWLES SOUTH;DEVONIAN	177
BAGLEY;SILURO / DEVONIAN	161

Table 4. Top pools by 2010 gas production rate. (Source: digitized+dwights)

Horizontal well development in this play has been minor; with only 16 wells completed since 1998; of which 10 were completed in the Denton (Devonian) in 2005. A comparison between the cumulative production from 2005 through March 2011 for horizontal vs vertical wells in the Denton is tabulated below. The average horizontal well outperformed the average vertical well over the given time period; exhibiting increased oil and gas recovery while simultaneously reducing water production. An economic analysis was not attempted and therefore it is not known if the horizontal well program was a viable project.

Parameter	horizontal	Vertical	Difference (H-V)
Average MBO/well	87	48	+39
Average MMCF/well	69	51	+18
Average MBW/well	794	1042	-248
Well count	10	57	

Table 5. Comparison of cumulative production (2005 to March 2011) between horizontal and vertical wells in the Denton Devonian Pool. (Source: GOTECH)

Recent new well completions are shown in figure 5. Only 81 new well completions occurred over the seven year time period, including 13 horizontal wells. The peak in 2005 reflects the Denton horizontal well program mentioned previously.

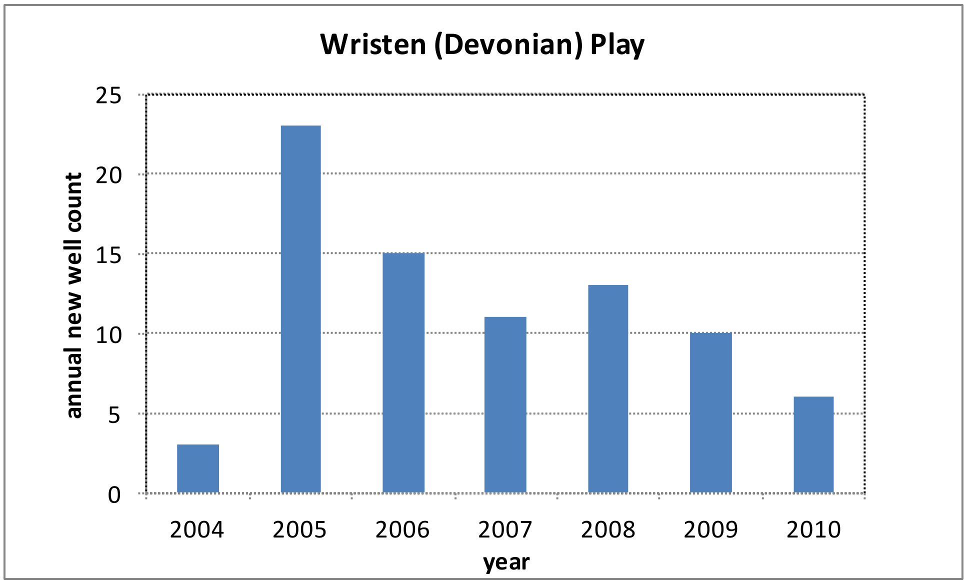


Figure 5. Recent new well activity. (Source: GOTECH)

Predicted Development

The mature status, the high water production, and the relatively deep depth of Devonian pools results in limited future development.

Several of these pools (Bagley, East Caprock, Denton and Dollarhide) have been screened as amenable to EOR – CO_2 (ARI Report, 2006). From a technical viewpoint, bypassed oil in these reservoirs can be contacted by the CO_2 resulting in increase in production. This has been demonstrated in several Devonian pools in West Texas. From a feasibility viewpoint, the lack of availability of CO_2, the cost to implement and the availability of other more promising EOR-CO_2 areas, are all significant obstacles to overcome.