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Water Injection in WIPP Vicinity:

Current Practices, Failure Rates and Future Operations

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1.0 Introduction

A June 1997 report entitled, *Injection Methods: Current Practices and Failure Rates in the Delaware Basin* reviewed oilfield injection activities and practices in the nine townships contiguous to the Waste Isolation Pilot Project. The 1997 report begins: "Critics of the Waste Isolation Pilot Project (WIPP) have often cited the existence of exploration activities and production of petroleum resources in the immediate vicinity of the WIPP site as sufficient reason to abandon the site for use as a nuclear waste disposal facility. One reason given is that the petroleum industry routinely uses water flooding techniques for pressure maintenance or secondary recovery of petroleum, or uses wells for waste (salt) water disposal. These activities are postulated by WIPP critics to induce water into the WIPP repository under pressure, thereby leading to rapid movement of radionuclides dissolved in brine within the WIPP disposal rooms toward the WIPP site boundaries, and thus leading to a violation of the release standards of Title 40 Code of Federal Regulations (CFR) Part 191 (EPA, 1993)."[1,15] Data from the original 1997 report provided important input data "of the failure rate of water injection (WI) and salt water disposal wells (SWD)" for computer models to predict the consequences of said activities in and near the WIPP site. An April 3, 2003 Injection Report, an August 2008 Injection Report, and a new report (this document) all follow a similar methodology and provide important data concerning oilfield water injection within the nine township area. In many respects, this report updates the data from the prior reports. Consequently, many references are made to the April 2003 and August 2008 reports, and many, but not all, of the discussions previously offered are repeated herein. This report also includes a projection of future water injection development based upon an analysis of current activities.

The analysis of oilfield injection activities and practices surrounding the WIPP site is limited to nine sections, including (1) the township where the WIPP site is located (22S 31E) and (2) the surrounding eight townships. In all, these townships cover an area of approximately 324 square miles, being roughly 18 miles by 18 miles in dimension. This area was selected because the geological characteristics within this area, which include, but are not limited to, lithology, depositional environment, stratigraphy, reservoir fluid properties, geothermal gradient and geostatic pressures, would be similar to any sites where future drilling activity near the WIPP site might occur. Thus these townships are representative of present and future activity.

For this report, all water injection wells in the subject area were analyzed. This includes both active injection wells, those that are presently injecting water into reservoirs (based on January 1, 2013 status), and inactive

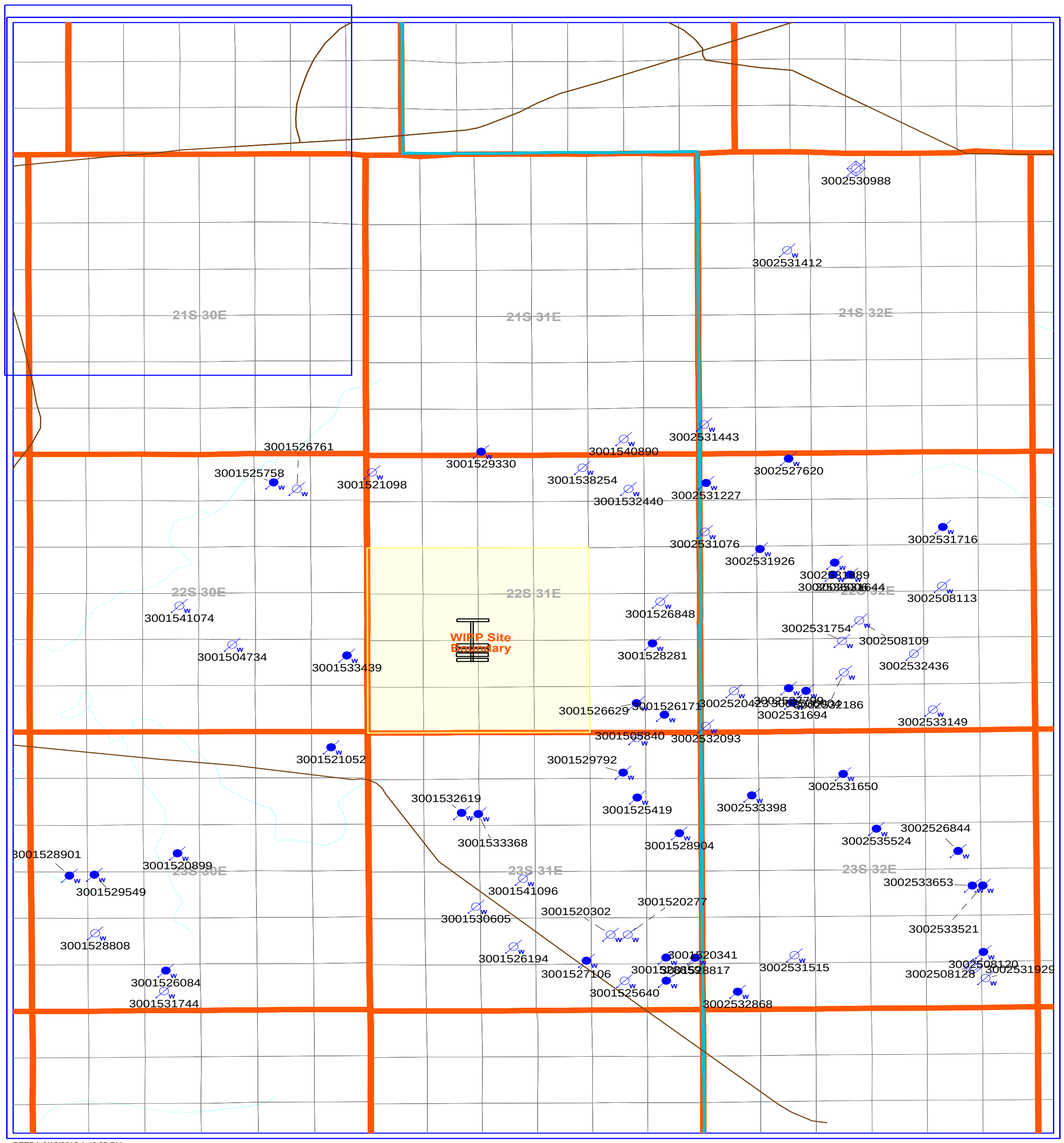

Figure no. 1 – Water Injection Wells – Labeled with API no.

injection wells (also based on January 1, 2013 status), those that injected water in the past but are now shut-in, plugged or recompleted to a hydrocarbon productive horizon. Figure 1 shows the active and inactive water injection wells within the nine-township study area. Active injection wells are further divided into two categories (1) wells which previously produced hydrocarbons, but were later converted to water injection wells (solid blue circle) and (2) wells that have exclusively been used as water injection wells (hollow blue circle). Presumably, for this last group, the well was originally drilled to test for hydrocarbon production, but being unsuccessful at finding commercial quantities of hydrocarbons, became a water injection well. Figure 1 does not distinguish between active and inactive injectors.

Finally, we analyzed the purpose of each water injection well to categorize the well as either (1) a salt water disposal well or (2) a reservoir enhancement well. The primary purpose for a salt water disposal well (SWD) is to dispose of produced water, a common byproduct of hydrocarbon production. For a SWD, water is typically injected into either (1) a non-commercial hydrocarbon bearing reservoir or (2) a hydrocarbon bearing reservoir, but is of sufficient distance from oil and gas productive wells as to exhibit little or no effect on production. This contrasts to water injection wells that are designed to enhance hydrocarbon production rates and recovery, and includes both the processes of waterflooding and pressure maintenance. In these instances, water injection into a productive reservoir is hoped to increase hydrocarbon production through a combination of fluid displacement and increasing reservoir pressure. "Waterflooding is dominant among fluid injection methods and is without question responsible for the current high level of producing rate and reserves within the U. S. and Canada."[2]

Of particular interest are water injection wells that fall into this last category of reservoir enhancement wells. These will be discussed more fully in the section titled *Waterflood Development*.

To orient the reader, Appendix I is a list of injection well test data, Appendix II includes various maps of the study area surrounding the WIPP site. A complete inventory of all producing wells in the study area is including as Appendix III. Appendix IV contains the normalized production data by reservoir. Appendix V is a copy of the New Mexico regulations: Title 19 Natural Resources and Wildlife, Chapter 15 Oil and Gas. Appendix VI is a copy of the New Mexico Underground Injection Control (UIC) Program. Appendix VII contains rate vs. time plots for all injection wells in the study area. Appendix VIII contains a list of mapping symbols.

2.0 Recent Water Injection Development

The 1997 *Injection Methods: Current Practices and Failure Rates in the Delaware Basin* report, identified a total of 26 injection wells with 21 active salt water disposal (SWD) wells, three active water injection wells and two temporarily abandoned or inactive SWD wells in the nine township study area. In the April 2003 Injection Report, 39 total injection wells were identified with 36 SWD or injection wells active and 3 wells temporarily abandoned or inactive. In the April 2008 Injection Report, 54 total injection wells were identified with 51 SWD or injection wells active and 3 wells temporarily abandoned or inactive. As of 1/1/2013, a total of 64 total injection wells are identified with 58 SWD or injection wells active and 6 wells temporarily abandoned or inactive. This represents an increase of 7 new SWD or water injection wells since the April 2008 Injection Report. Average daily injection into all wells is now at approximately 73,000 barrels of water injected per day (BWIPD) or approximately 1,270 BWIPD per well. This compares to average daily injection of 77,000 BWIPD at the end of 2007 or approximately 1,480 BWIPD per well. Therefore, injection rates have decreased slightly over the past 5 years.

3.0 Regulatory Requirements

The subject area surrounding the WIPP lies exclusively within the State of New Mexico and is subject to the Uniform Injection Code, which is administered by the New Mexico Oil Conservation Division (NMOCD). The Uniform Injection Code applies to all wells located in New Mexico whether the minerals are owned by private individuals, the State of New Mexico or the U. S. Federal government. The regulations governing water injection are stated in rules **19.15.9.701** through **19.15.9.710** and are included as Appendix V. The rules apply to injection for secondary or other enhanced recovery, pressure maintenance, salt water disposal and underground storage. Rule **19.15.9.701.a** states "The injection of gas, liquefied petroleum gas, air, water, or any other medium into any reservoir for the purpose of maintaining reservoir pressure or for the purpose of secondary or other enhanced recovery or for storage or the injection of water into any formation for the purpose of water disposal shall be permitted only by order of the Division after notice and hearing, unless otherwise provided herein."[3] Consequently, permitting and monitoring of water injection wells are closely regulated by the NMOCD to maximize hydrocarbon recovery, protect correlative rights and ensure protection of the environment, both above and below the ground surface.

3.1 Testing

Injection wells move water from surface facilities to subsurface reservoirs. The nature of fluid flow into a permeable media is a well documented and understood mechanism. The rate of fluid movement is proportional to the pressure differential between the sandface and the average reservoir pressure. Thus water injection wells involve some form of pressure in the wellbore, resulting from a combination of hydrostatic pressure (the weight of the water column) and injection pumps. To ensure the injection water is disposed into only the target interval, the NMOCD outlines cementing requirements (see NMAC **19.15.9.702**), operational procedures (see NMAC **19.15.9.703**) and periodic testing (see NMAC **19.15.9.704**). Cementing requirements state the wellbore casing "shall be so set and cemented as to prevent the movement of formation or injected fluid from the injection zone into any other zone or to the surface around the outside of any casing string."[5]

The NMOCD uses two types of tests to ensure wellbore integrity of water injection wells, the Bradenhead Test and the Mechanical Integrity Test. Typically a Bradenhead Test (BHT) is conducted annually and a Mechanical Integrity Test (MIT) is conducted at five-year intervals or anytime that a well is taken off-line for repairs; however, the actual frequency of these tests may vary based on permit conditions.

The BHT is performed by opening the bradenhead valve to the atmosphere. If gas or water flow is observed or indicated, flow through the bradenhead valve is allowed to continue for a minimum of fifteen minutes. During this period, pressures are recorded at five-minute intervals on the production, intermediate and surface casing. Any fluids flowing from the bradenhead valve, including measured or estimated rates of flow, are described in detail.

The BHT tests the integrity of the tubing and packer. The tubing annulus, the volume between the tubing and the casing, is typically filled with a corrosion-inhibiting fluid. If a leak in the tubing or packer exists, the annulus becomes pressurized and flow occurs when the valve is opened.

The MIT tests the integrity of the casing and must be performed prior to injection and/or any time the tubing is pulled or the packer is reseated. In this test the tubing-casing annulus is pressurized to a minimum of 300 psia. A pressure recorder shows any loss of pressure over a 30-minute period. Copies of the pressure recorder chart must be submitted to the NMOCD within 30 days of the test date. A sudden drop in pressure indicates annular fluids are leaking out and constitutes a test failure. If a well fails a test, it is shut-in and the operator must take corrective action before returning the well to service.

During the past ten years, the NMOCD changed the record keeping procedure for BHT and MIT tests. Previously, hard copy reports were filed at each regional NMOCD office documenting the test results. For our 2003 evaluation, we visited the Artesia and Hobbs offices and copied these reports for independent analysis. Sometime in 2005, the NMOCD converted to an electronic database system to track Underground Injection Control (UIC) test results. The database contains both historical BHT and MIT tests (those obtained prior to the conversion) and recent tests (conducted after the conversion). This system replaced the manual filing system and eliminated the need to retain hard copy reports. For the 2008 and 2013 evaluations, we requested a query of the electronic database from each regional office and received an ASCI text file containing the subject data.

As part of the 2005 conversion process, the NMOCD also implemented an automated process to notify operators of upcoming BHT and MIT tests, thereby eliminating the need of manually tracking and scheduling these tests. Although these electronic methods should improve reliability, we discovered some deficiencies in the system.

First, well test data are missing from the MIT and BHT electronic database. The accompanying table identifies 24 wells (38 percent) for which we could not locate historical MIT and/or BHT tests in the NMOCD query during the subject 5 year period. In some cases, the tests may have been conducted but not recorded in the NMOCD electronic database.

Well Name and No.	Operator	API Number	County	Missing Date
Aracanga Federal No. 1	Oxy USA Inc.	30-025-31650	Lea	2008, 2012
Bitsy Federal SWD No. 1	Enervest Operating, LLC	30-025-33398	Lea	2010, 2012
Cuervo Federal No. 1	Strata Production	30-025-26844	Lea	2011, 2012
Diamondtail 24 Federal A No. 1	Concho Resources	30-025-33521	Lea	2010
Diamondtail 23 Federal No. 2	Devon Energy	30-025-33653	Lea	2011
Flamenco Federal No. 1	Yates Petroleum	30-025-31076	Lea	2008
Gilmore No. 1	Strata Production	30-025-08109	Lea	2008, 2011,2012
James A No. 1	ConocoPhillips	30-015-25758	Eddy	2008, 2009, 2010, 2011, 2012
James Federal No. 1	Harvard Petroleum	30-025-31515	Lea	2008, 2010, 2012
Lost Tank SWD No. 1	Phillips Petroleum	30-025-31443	Lea	2010, 2011, 2012
Prize Federal No. 4	Oxy USA Inc.	30-025-32436	Lea	2008, 2012
Prohibition Federal Unit No. 2	COG Operating LLC	30-025-31716	Lea	2010, 2012
Proximity 31 Fed No. 4	Oxy USA Inc.	30-025-20423	Lea	2008, 2010, 2012
Red Tank Federal No. 2	EOG Resources Inc.	30-025-08113	Lea	2008
Red Tank Federal 28 No. 3	Oxy USA Inc.	30-025-31754	Lea	2008, 2012
Red Tank Federal 35 No. 3	Oxy USA Inc.	30-025-33149	Lea	2008, 2012
Sand Dunes 28 Fed No. 1	OXY USA Inc	30-015-26194	Eddy	2012
SDE 31 Federal No. 9	XTO Energy, Inc	30-025-32868	Lea	2008, 2009, 2011, 2012
Silverton '31' Fed 1	Echo Production	30-025-32093	Lea	2008, 2010, 2012
South Culebra Bluff 23 No. 17	Range Operating	30-015-35510	Eddy	2008, 2009, 2010, 2011, 2012
South Culebra Bluff 23 No. 18	Range Operating	30-015-35511	Eddy	2008, 2009, 2010, 2011, 2012
South Culebra Bluff 23 No. 19	Range Operating	30-015-35512	Eddy	2008, 2009, 2010, 2011, 2012
South Culebra Bluff 23 No. 20	Range Operating	30-015-35513	Eddy	2008, 2009, 2010, 2011, 2012
South Culebra Bluff 23 No. 21	Range Operating	30-015-35514	Eddy	2008, 2009, 2010, 2011, 2012
Triste Draw State 36 No. 1	EOG Resources Inc.	30-025-31929	Lea	2008

Table no. 1 – Missing UIC Tests in Study Area

Secondly, the automated notification system does not encompass all of the injection wells. Consequently NMOCD notices were not sent and some injections wells have not been tested since 2007. It appears the conversion process failed to capture all injection wells, consequently operators were not notified of annual testing for these wells. It appears the 6 wells (10 percent) missing consecutive tests in 2008, 2009, 2010, 2011, and 2012 likely fall into this category. Of the two deficiencies, we believe the second is more severe.

3.2 Type of Failures

The June 1997 *Injection Methods: Current Practices and Failure Rates in the Delaware Basin* identified five types of injection well failures. These include (1) tubing leak, (2) packer leak, (3) casing leak, (4) breakdown of cement sheath and (5) hydraulic fracturing by injecting fluids out of zone. Based upon NMOCD practices, we would add a sixth type of failure, (6) an inability to conduct a test. Although this does not constitute a mechanical failure, the NMOCD considers a test failed if the test cannot be conducted. The bradenhead test and mechanical integrity test are designed to detect the first three types of failures. Sudden changes in annular pressure occur during these types of failures as the injection fluids pressurize the annulus during a tubing or packer leak while annular fluids migrate into a surrounding reservoir during a casing leak, thereby decreasing pressure (please see Appendix VI for an injection well wellbore schematic). None of these failures individually result in out of zone injection. The prior report found "given the infrequency of tubing and packer leaks…, and the infrequency of casing leaks, the probability of these two leaks occurring simultaneously is very, very low"[1]. This conclusion remains valid, based on recent failure data. Furthermore, these failures are readily detected and repaired. Therefore these failures do not impact the WIPP site since any injected fluids are contained within either the tubing or casing and do not migrate out of the desired injection interval.

For the fourth failure type, breakdown of cement sheath, the prior report summarizes this condition very well. The report states, "the breakdown of the cement sheath between the casing and/or the borehole wall, is the only leak scenario that has the potential to impact the WIPP repository. This type of failure can only be detected by a radioactive tracer test (RTT) survey conducted inside the cased wellbore. This type of test is not a normal regulatory requirement, but may be conducted if it appears there may be fluid migration behind casing. There are several diagnostic tools for indirectly detecting fluid migration behind casing. For example, if a WI well operated to enhance oil production (i.e., waterflood operations) caused migration out of zone, anticipated recovery would not meet the predetermined expectations of the operator, thereby affecting the economics of the waterflood project. Prudent operators of waterflood projects will not allow injection fluids to migrate out of zone. Further, it is a violation of NMOCD regulations to allow migration of fluid out of the target zone."[3] We would add that most operators of waterflood operations conduct periodic temperature surveys to identify the intervals where injected water travels. Since the injected water is cooler than the surrounding formations, intervals of injection exhibit below normal temperatures. This diagnostic tool is used to identify problems with injection conformance and to confirm the success of corrective actions.

The 1997 report also noted "if the cement sheath in a SWD is compromised by the injection process and fluid migrates upward, it is more likely that this event would go undetected for a greater period of time than for a WI well. However, the low permeability of the cement will preclude the migration of injected water through the cement sheath. One hundred percent bonding between cement/casing and cement/formation is not necessary to insure a hydraulic seal. Sixty to eighty percent cement bonding over a distance of 25 – 50 feet for 5.5 inch casing and 60 – 125 feet bonding for 8.625 inch casing is adequate to insure a hydraulic seal for injection purposes (Schlumberger 1989). Note that the minimum length of any cement sheath (production casing) within the study area is 140 feet."[1] We have not reviewed wells drilled since this 1997 report to determine if any wells have cement sheaths less than 140 feet.

Failure type 5, hydraulic fracture of injection fluids out of zone could occur if the pressure of the injection fluid exceeded the fracture pressure of the formation at the sand face. In general, fracture pressures typically exceed 0.8 psi per foot of depth, thus for depths ranging from 5,000 feet to 8,000 feet, the respective fracture pressures would be approximately 4,000 psi and 6,400 psi. The NMOCD requires the surface pressure not exceed 0.2 psia per foot of depth to the top of the perforations. Since the hydrostatic pressure of a column of water is .435 psi per foot (for a salt saturated solution), the maximum sand face pressures are 3,175 psi at 5,000 feet and 5,080 psi at 8,000 feet. Both are significantly below the corresponding fracture pressure at depth and are therefore incapable of inducing a vertical fracture.

The sole exception to the NMOCD ban on injection above 0.2 psi per foot of depth are for temporary tests, known as step-rate tests, to determine actual formation parting pressure (the pressure that induces a vertical fracture). In this test, water is initially injected at a low pressure and the injection rate measured. The injection rate is then "stepped-up" to a higher pressure using a predefined increment of perhaps 100 psi or 200 psi. Again the injection rate is measured. The process is then repeated at successively higher injection pressures. As long as the injection pressure is below the parting pressure, the increase in injection will be proportional to pressure.[4] Thus each 100 psi increase in injection pressure translates into a like increase in injected volume. Mathematically this yields a ratio such as 5 barrels per psi.

Once the injection pressure exceeds the parting pressure, the injection rates increase much more rapidly, thus the ratio of injection to pressure increases, perhaps to 10 barrels per psi. The parting pressure, the pressure that induces a vertical fracture, is determined from the pressure at which injection rate first increases rapidly, and the maximum pressure allowed is set below the measured limit. Although the formation is fractured or parted during the test, the fracture heals once the pressure in the fracture drops below the parting pressure. Thus the fracture results of the test are temporary.

Finally, the 1997 report extensively addressed the geometry of a fracture created by injecting above parting pressure. Therefore please see pages 10 and 11 of the prior report for a thorough discussion of this behavior. To summarize, because water, the injectant, has a relatively low viscosity (0.60 centipoises at 140 °F), the fluid moves rapidly into the surrounding formation and generates little fracture height. This behavior, known as leak-off, results in very little fracture volume due to saltwater injection. Thus the creation of a vertical fracture (with height in excess of a few tens of feet) is highly improbable at the injection rates reviewed in the study.

4.0 Historical Injection Well Failures

Appendix I summarizes all the Bradenhead and Mechanical Integrity Tests for wells in the study area. Table no. 2 itemizes Bradenhead and Mechanical Integrity Test failures in the nine township study area since 2007. Furthermore, the table shows the cause for the failed test and the remedial action required to return the well to injection.

Well Name and No.	Test Date	Test Type	Reason for Failure	Action	Failure Type
Apache 25 Federal No. 8	Oct 2009	MIT	Csg would not hold pressure	repaired, retest 4/22/10. test OK	3
Charger 29 Federal No. 1	Oct 2010	MIT	Csg would not hold pressure	Repair csg, Retest12/20/2010, test OK	3
Cuervo Federal No. 1	Aug 2010	MIT	Operational violation	Retest 8/19/2010, test OK	?
Diamondtail 23 Federal No. 2	Sep 2011	MIT	Pressure on tbg & csg	Repair, Retest 2/17/2012, test OK	1,3
Diamondtail 24 Federal A No. 1	Apr 2013	MIT	Csg would not hold pressure	plans to repair	3
Gilmore No. 1	Mar 2009	MIT	Csg would not hold pressure	ran 51/2 ' liner; retest 8/18/2010; test OK	3
James A No. 12	Nov 2010	Brdhd Test	Hole in tubing	Replace tbg, retest 11/30/2010, test OK	1
Lotus SWD No. 1	Dec 2010	MIT	well is down, did not test	casing repair , retest 1/11/2011, test OK	3
Neff Federal 003	Oct 2012	Brdhd Test	casing leak	replace pkr, retest 12/5/12, test ok	3
Todd Fed 26F No. 3	Oct 2010	MIT	casing leak	repair, retest 2/14/2011, test OK	3
Todd Fed 26G No. 2	Sep 2009	Brdhd Test	inj pressure over max limit	retest 10/21/09, test OK	?
Todd Fed 27P No. 16	Sep 2009	Brdhd Test	inj pressure over max limit	notice of intent to P&A	?
Todd 36 State No. 1	Oct 2010	MIT	Csg would not hold pressure	Replace tbg, retest 11/17/2010, test OK	1

Table no. 2 – BHT and MIT Failures in Study Area

Thirteen test failures were identified for the 64 injection wells in the study area. However, note that two of the tests failed due to an inability to conduct a test. The Cuervo Federal 1 had an operational violation, and the Lotus SWD 1 was down. In this situation, a testing failure occurs since a test can not be conducted and is so noted in the OCD records. If these failures are excluded, which seems reasonable since no mechanical failure actually occurred, then 11 mechanical failures are observed. The most common cause for failure was a casing or tubing leak. In each case, the problem was repaired and the well returned to injection.

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5.0 Oil and Gas Productive Formations

Oil and gas in the study area, itself a part of the vast Delaware Basin, are produced from several different formations, including Delaware Mountain Group, Bone Spring, Wolfcamp, Atoka, and Morrow. The Delaware Mountain Group can be further subdivided into Bell Canyon, Cherry Canyon and Brushy Canyon, but production is principally from the latter two in this area. The accompanying stratigraphic section (figure no. 2) shows the relative depths at which these formations are encountered in the study area. Two of the Permian age formations, Delaware and Bone Spring, are generally oil bearing and produce via solution gas expansion. The other Permian age formation, the Wolfcamp, may be either oil or gas bearing, while the Pennsylvanian age Atoka and Morrow clastics produce gas and some condensate. Both the Atoka and Morrow produce under simple gas expansion.

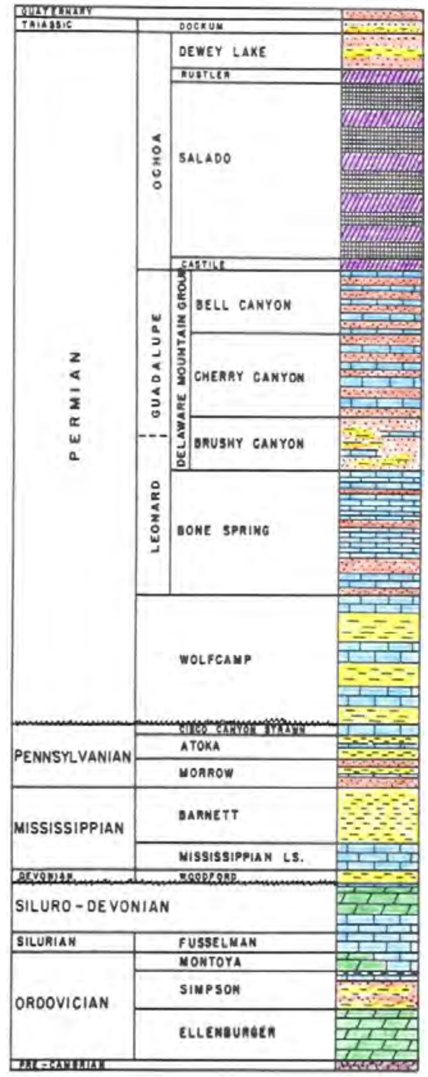

Fig no. 2 – Delaware Basin Stratigraphic Section (not to scale)

In the study area, the Delaware Mountain Group produces from the Cherry Canyon and the deeper Brushy Canyon. Both formations include layers of clastic sands, organic-rich siltstones and carbonate materials. In general, the cementing material is calcareous and porosity appears to be controlled by the amount of the cementing material present. "Cyclicity was a major factor in the deposition of the Brushy Canyon."[5] Changes in sea level allowed for massive carbonate buildups along the shelf-basin margin which, during periods of relatively high sea level, trapped sediments on the shelf. When sea level fell, the trapped clastics flowed toward the basin and were deposited in vast sandstone and siltstone units. Although the exact mechanism of submarine sediment transport is debated, the result was a collection of interbedded sandstones and organic-rich siltstones that are cut by massive channel-type sandstones. The sea level change occurred repeatedly and numerous layers of sand and siltstone occur in these reservoirs. Consequently, reservoirs are typically discontinuous, both laterally and areally.

The prolific reef build-up around the boundaries of the Delaware Basin was eventually the cause of its own death. Margin reefs gradually grew together and blocked the flow of sea water from the shelf margin.[6] This change, along with climatic events, produced conditions of evaporation in the Delaware Basin. The result was the formation of the large evaporite sections of salt, gypsum, and anhydrite and represent the dying stages of the Permian as the seas retreated to the southwest.

The Bone Spring Formation of Leonardian age is composed of three carbonate units that are separated by three clastic units. The sands were deposited as debris flows from the Abo-Yeso shelf edge during periods of relatively low sea level and extend many miles into the basin. The carbonates, in contrast, were deposited during high sea level when carbonate production was greatest.[10] Facies changes are frequent, both due to depositional conditions and diagenetic changes. Porous dolomitic lenses often change to non-porous limestone while porous sandstones frequently change laterally to non-porous dolomite and siltstone. As with the Delaware Mountain Group formations, reservoirs are very discontinuous, so much so that different facies are often observed in adjacent wells. For example, a carbonate deposit in one well may become almost absent in an east or west offset and transition to sand. This type of facies change is especially prevalent to the north, closer to the shelf margin.

The Morrow formation encompasses three distinct clastic intervals – Lower, Middle and Upper – each separated by a major flooding surface with the Lower Morrow boundary at the top of the Mississippian unconformity. The intervals are each dominated by a particular depositional environment with the Lower Morrow being delta plain, the Middle Morrow being delta front and the Upper Morrow being carbonate shelf.[7,8] Although these were the dominant environments, numerous sub-environments (facies) also existed including distributary channel-fill sands, channel mouth bars, and beach and barrier bar deposits. These later facies reflect the reworking of the upper portions of sand deposits by wave and wind action. The many sand deposits are typically capped by transgressive marine shales and thin carbonate deposits. Because of the complex depositional environment, the Morrow age sands typically cover a limited areal extent and the sands encountered in one well are very often different than those encountered in an offset well.

The common trait of all of these formations is reservoir discontinuity. Hence reservoirs may be characterized as relatively small, separated units. Even in a single field, production is normally from several different reservoirs. For example, in the Cabin Lake (Delaware) Field, production is from multiple sands in both the Cherry Canyon and Brushy Canyon intervals.

Formation	Completions	Cumulative Oil (barrels)	Cumulative Gas (Mcf)	Cumulative Injection (barrels)
Delaware	1354	90,708,000	215,515,000	353,400,000
Bone Spring	234	5,381,000	20,712,000	0
Wolfcamp	33	1.038,000	8.182,000	0
Strawn	13	366,000	11,791,000	0
Atoka	57	531,000	111,527,000	0
Morrow	139	1,485,000	252,482,000	2,579,000
Dry Holes	204	0	0	0
Other	28	1,367,000	4,474,000	21,000,000

Table no. 3 – Cumulative Oil and Gas Production in Study Area on 12/31/2012 (data from Lasser Production Data)

Table no. 3 shows the relative contribution of each formation as it relates to well count, cumulative oil production, cumulative gas production and cumulative water injection. As this table shows, Delaware wells (1,354) constitute the vast majority of total producing wellbores, followed by Bone Spring (234) then Morrow (139). Please note that “Dry Holes” and “Other” refer to the producing well status as all water is presently injected into the Delaware formation. The Delaware and Bone Spring oil wells typically are drilled on 40-acre spacing (16 wells per section). A tight spacing is required to adequately drain the formations due to the following reasons: (1) the reservoirs tend to be laterally and areally discontinuous, (2) the reservoirs are low permeability and (3) the produced fluids (oil and water) are relatively viscous. Hence many wellbores are needed to effectively drain these reservoirs. Even on 40 acre spacing, recovery efficiency is fairly poor and could probably benefit from denser spacing. Average cumulative production is 67,000 barrels and 159,000 Mcf for each Delaware well (1,354 wells). A normalized rate versus time plot for the Delaware wells in the study area is included in Appendix IV. Based upon the normalized production curve, remaining reserves in the Delaware completions are 57,000 barrels and 156,000 Mcf, yielding a Delaware per well estimated ultimate recovery (EUR) of 124,000 barrels and 315,000 Mcf. Table 4 provides further details for the four major formations for resource extraction activities.

Bone Spring completions average 23,000 barrels and 88,500 Mcf cumulative production per well (234 wells). A normalized rate versus time plot for the Bone Spring wells in the study area is included in Appendix IV. Based upon the normalized production curve, remaining reserves in the Bone Spring completions are 43,000 barrels and 171,500 Mcf, resulting in a Bone Spring per well EUR of 66,000 barrels and 260,000 Mcf.

	Delaware	**Bone Spring**	**Atoka**	**Morrow**
Cumulative Oil Production (bbl)	67,000	23,000	9,300	11,000
Estimated Remaining Oil (bbl)	57,000	43,000	3,700	5,000
Estimated Ultimate Oil (bbl)	**124,000**	**66,000**	**13,000**	**16,000**
Cumulative Gas Production (mcf)	159,000	88,500	1,956,000	1,816,000
Estimated Remaining Gas (mcf)	156,000	171,500	649,000	1,079,000
Estimated Ultimate Gas (mcf)	**315,000**	**260,000**	**2,605,000**	**2,895,000**
Cumulative Equiv Bbl	93,500	37,800	335,000	314,000
Estimated Remaining Equiv Bbl	150,000	71,600	112,000	185,000
Estimated Ultimate Equiv Bbl	**176,500**	**109,000**	**447,000**	**499,000**

Table no. 4 – Average Production and Projected Oil and Gas Recoveries in Study Area
(All Volumes are per well averages)

In contrast, the deeper Atoka and Morrow gas wells, while sharing the characteristic of discontinuity, produce a lower viscosity fluid (gas) and are capable of draining a larger area. Studies by Hall[9] suggest the average area drained by Morrow wells is between 90 to 100 acres with some wells draining in excess of 400 acres. Therefore only 57 and 139 Atoka and Morrow gas wells, respectively, are encountered in the study area. Cumulative Atoka production is at 1.956 Bcf and 9,300 barrels per well. Remaining reserves are projected at 0.649 Bcf and 3,700 barrels, yielding a per well EUR of 2.605 Bcf and 13,000 barrels for Atoka gas wells.

Morrow gas wells average 1.816 Bcf and 11,000 barrels cumulative production per well. Based upon the normalized production curve, remaining reserves in the Morrow completions are 1,079 Bcf and 5,000 barrels, resulting in a Morrow per well EUR of 2.895 Bcf and 16,000 barrels.

When compared to EUR's from the 2008 study, well performance is generally better.

6.0 Projection of Future Activities Based on Current Conditions

The following graph (figure no. 3) shows a distribution of drilling activity for each year in the study area since 1970. Additional information for these wells is found in Appendix III. This graph shows gradual ongoing development of oil and gas wells during the first two decades with a marked increase in activity starting in 1990.

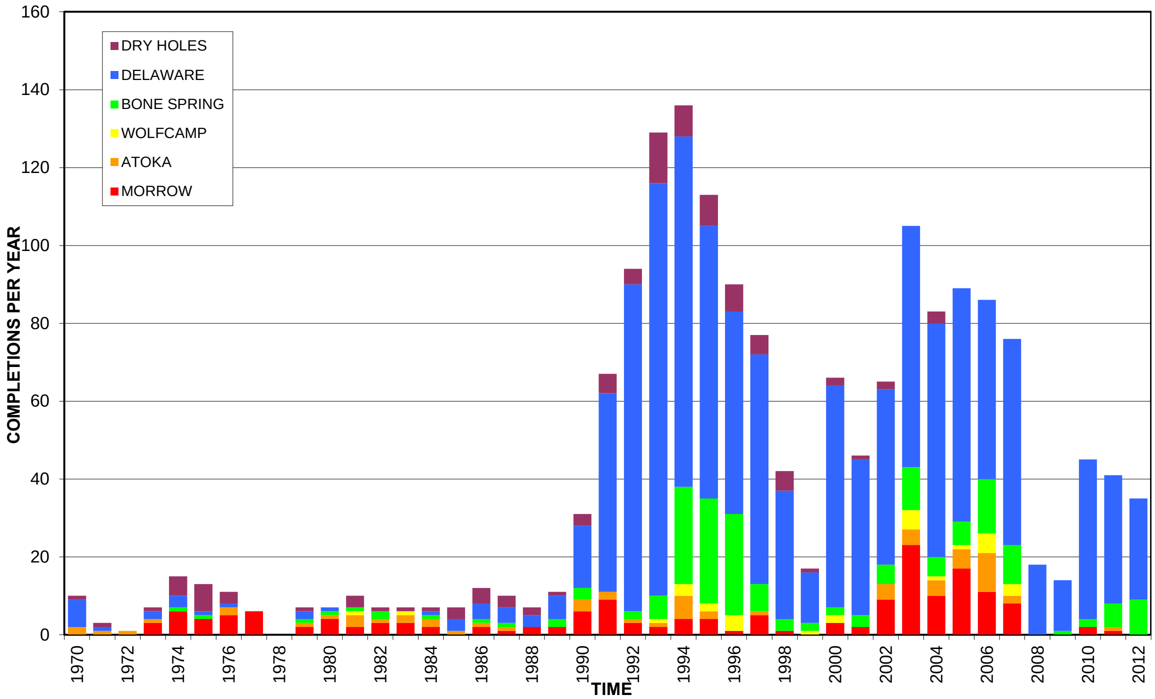

Figure no. 3 – Well Completions vs. Time in Study Area

Drilling continued at a fast pace of about 100 to 130 wells per year through the 1990's until the oil price collapse in late 1998. As commodity prices improved starting in 2000, the drilling rate rose correspondingly to 60 to 100 wells per year. However, in spite of dramatically higher oil and gas prices in the past few years, new well permits are exhibiting a decreasing trend during the 5 year study period with 18, 43, 58, 60, and 50 permits issued in 2008, 2009, 2010, 2011, and 2012, respectively. These numbers consider the first issuance of a permit and do not include permits reissued for the same well once a permit expires. At year-end 2012, 59 wells were permitted yet undrilled. The NMOCD issues drilling permits for a one year period which expire if drilling operations have not commenced. We have not determined the current status (active or expired) of the 59 permits issued in the study area.

As the graph illustrates, wells targeting the Delaware Mountain Group constitute the majority of drilling since 1985. Discussions with operators in the study area confirm favorable economics for the Delaware formation and plans are underway by many operators to continue development of this formation with infill and extension drilling. If oil prices remain close to current levels, we believe Delaware well drilling will continue at 40 to 60 wells per year for at least five more years.

Bone Spring wells offer relatively low reserves of approximately 109,000 equivalent barrels per completion. However with the significant recent increase in commodity prices, the Bone Spring offers attractive economic returns and more wells have targeted this reservoir in recent years. Finally, the Bone Spring will likely be perforated and tested for commercial quantities of hydrocarbons in Atoka and Morrow gas wells once these reservoirs are depleted.

Operators typically consider the Pennsylvanian gas reservoirs, Atoka and Morrow, together since the channel sands are quite unpredictable. Thus a Morrow test often includes the Atoka as a "bail-out" or secondary target. Therefore, economics for these formations are calculated in this report assuming the Morrow is the primary target with the Atoka as the secondary target. A survey of post-1970 wells reveals 168 wells produced from the Morrow sands, but 13 of these were later recompleted into the shallower Atoka sands. Fifty-three wells produced from only the Atoka sands (presumably the Morrow was dry), while 22 dry holes encountered no production in either the Morrow or Atoka. Therefore, in all, 243 wellbores were drilled to test Pennsylvanian targets. Since the gas price collapse of mid-2008, Atoka and Morrow drilling has virtually ceased with only 1 or 2 wells completed each year. We expect future drilling to continue at this rate until gas prices recover.

A shift from vertical to horizontal well drilling marks the most significant development change since the 2008 review. The 2008 review included three horizontal wells. Since then, 94 horizontal wells penetrated the Delaware and Bone Spring formations accounting for about 80 percent of the completions during 2010 through 2012. Typically these wells drill 4,700 ft laterals in the target formation. Based on the attractive economics of horizontal completions, we anticipate the industry will favor ongoing horizontal development over vertical wells. Therefore, it is likely that additional horizontal wells will be drilled under the 16 section WIPP site boundary. Although we do not anticipate these horizontal wells to be attractive as injection wells, they will be hydraulically fracture stimulated during completion. Presently 100 additional horizontal wells are permitted in the study area.

The following graph (figure no. 4) depicts production and injection for all of the wells in the nine township study area. Monthly volumes for oil

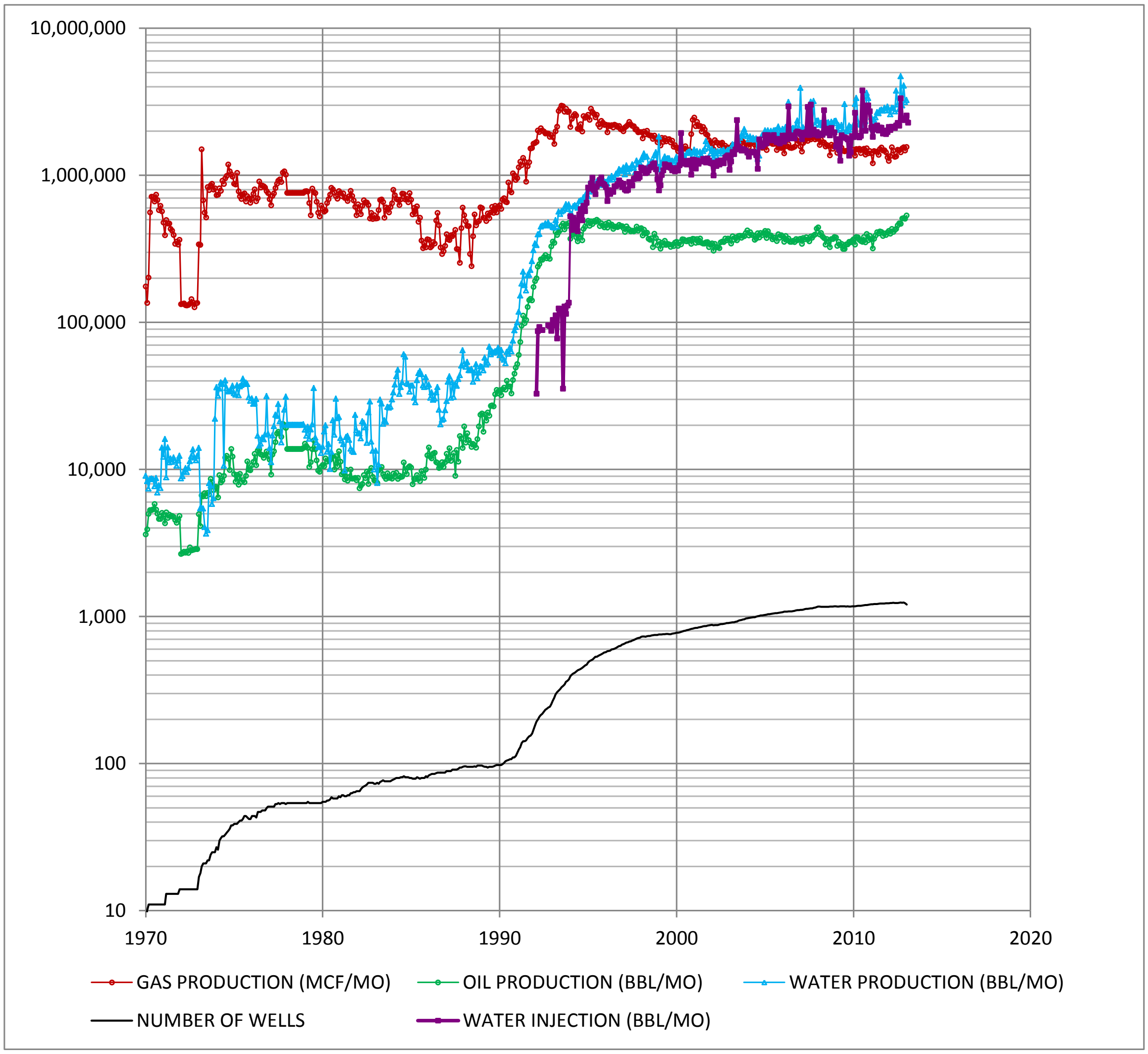

Figure no. 4 – Total Production vs. Time in Study Area

production, gas production, water production, water injection and well count are plotted versus time for a period from 1970 through 2013. This graph includes all wells regardless of productive interval (Morrow, Atoka, Bone Spring, Delaware, etc.) and all water injection wells. The graph illustrates several important features for wells in this area. First, *total water injection is essentially equal to total water production.* Obviously, little or no make-up water is injected. During the last five years, from 2008 through 2012, water production averaged 2,605,479 barrels of water per month while water injection averaged 2,090,170 barrels of water per month. The difference between these two values probably represents an error in water measurement. Since produced water, unlike oil or gas, is not sold, most operators allow for some error in determining produced water volumes.

6.1 Waterflood Development

We reviewed the performance of every producing well in the study area to determine if water injection influences oil and gas production. Two groups of wells appear to benefit from offset water injection. The first group, in the Cabin Lake (Delaware) Field, is located to the northwest of the WIPP site boundary in township 22S 30E (see map in Appendix II). The second group of wells is to the east of the WIPP site boundary in the Livingston Ridge (Delaware) Field in township 22S 31E. (see legend of symbols in Appendix VIII).

The first group, in the Cabin Lake (Delaware) Field, shows a response to water injection in James "A" no. 3 and James "A" no. 12. In this instance, six Delaware oil wells exhibit either (1) increasing production or (2) production that declines more gradually than is generally expected based upon field-wide characteristics. The responding oil wells are indicated in the accompanying map (figure no. 5) by orange circles.

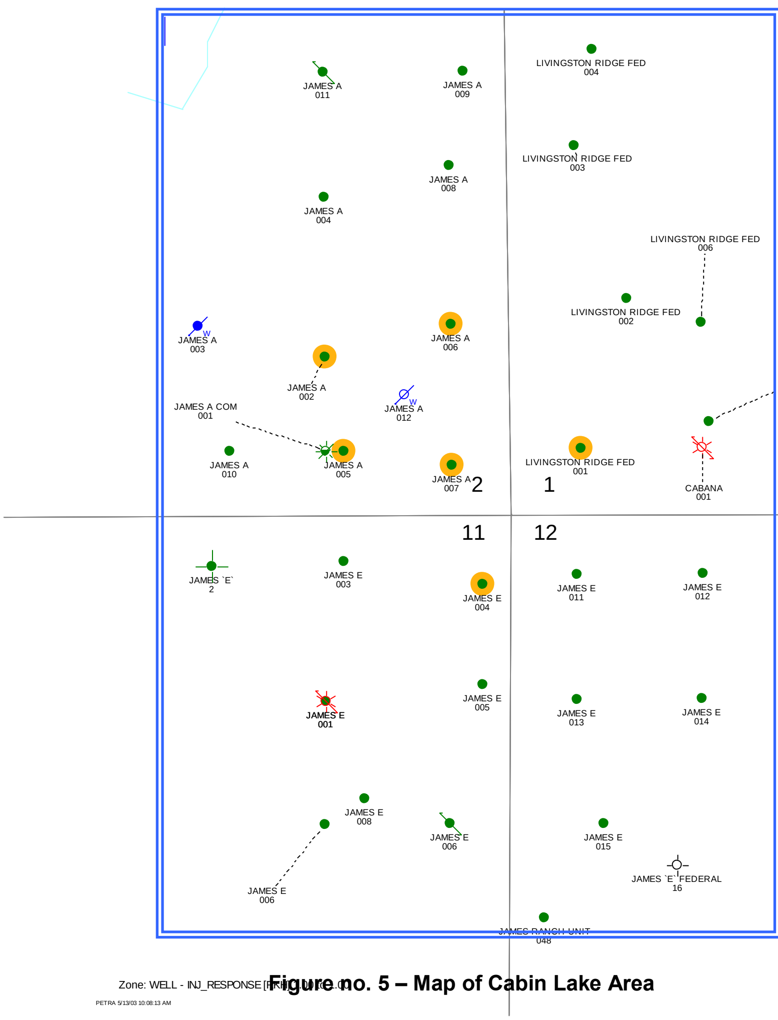

Figure no. 5 – Map of Cabin Lake Area

ConocoPhillips Company operates both the injection wells and producing wells. Discussions with the operator indicate no plans are presently in place to expand injection, either with larger volumes in the existing wells or with additional injection wells. Furthermore, the operator believes further study of the Delaware formation is needed before the working interest owners could approve such an expansion project. We believe the operator will not pursue an expansion of this project for several reasons. These include: (1) staff and financial resources do not appear to be directed toward such a project, (2) the total project is relatively small and offers little incentive for a large international major company, (3) lifting costs would increase substantially which appear contrary to corporate goals, (4) the Delaware formation is complex with little current understanding as to productive or injective intervals (both Cherry Canyon and Brushy Canyon intervals are open in producers and injectors) and (5) a source for make-up water is not readily available. These hurdles are significant, consequently we believe expansion of water injection in the Cabin Lake (Delaware) Field by ConocoPhillips Company is unlikely and anticipate the status quo (disposal of produced water) to be maintained.

The second area with response to water injection is found in the Livingston Ridge (Delaware) Field. Again the wells with response to water injection are indicated by orange circles (figure no 6). Three wells exhibited some improvement in production, apparently due to water disposal in the Neff Federal no. 3. However, producer response in this area is much poorer than observed in the Cabin Lake (Delaware) Field even though injection volumes are about the same at 2,000 barrels to 2,500 barrels of water per day.

In a 1995 SPE paper entitled *Characterization of a Delaware Slope Basin Reservoir for Optimal Development*, Weiss, Ouenes and Sultan of New Mexico Petroleum Recovery Research Center studied primary performance of the East Livingston (Delaware) Field. This field is located in township 22S 32E, about five miles east of the WIPP site boundary. Their work compared actual primary performance to a reservoir model consisting of seven layers, each corresponding to a different geological interval in the Brushy Canyon formation. After matching the model projected production to three years of production data, their work suggested a very low primary recovery factor (0.67 percent) for the current 23 producing wells.[10] This low primary recovery is consistent with the Avalon field with a projected primary recovery of 1.5 percent.[12] To improve total recovery, the authors modeled both (1) an infill drilling project and (2) a secondary recovery project using two uneconomic producers converted to water injection. For the water injection project, they concluded "the high watercut, low oil recovery characteristics of the simulated waterflood suggest that it is

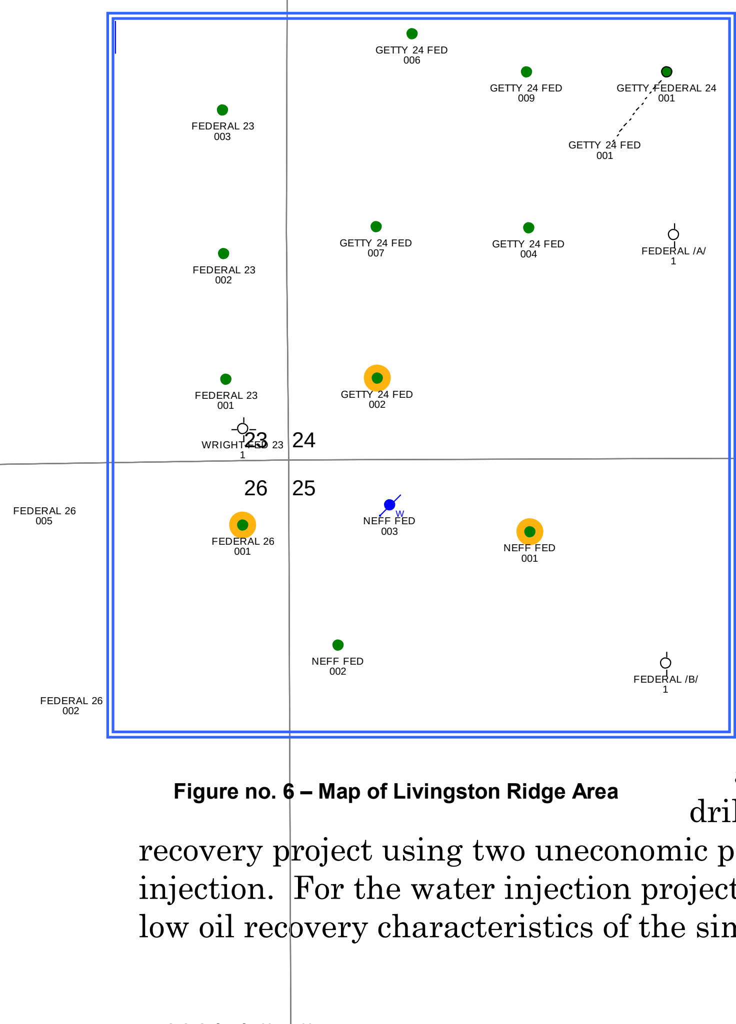

Figure no. 6 – Map of Livingston Ridge Area

not a viable strategy".[11] Jenkins suggested high interstitial water saturations might result in inefficient flooding of the Delaware sands.[13] Based on lack of response to injection in this field, these conclusions seem reasonable.

7.0 Reservoir Fill-Up

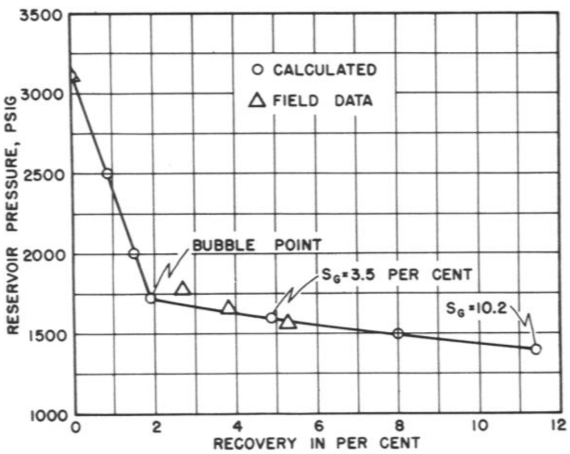

Figure no. 7 –Reservoir Pressure vs. Recovery

As reservoir fluids (oil, gas, water) are produced in undersaturated oil reservoirs, reservoir pressure decreases. The Delaware formation in the study area is considered an undersaturated oil reservoir based on performance characteristics. The accompanying graph (figure no. 7), after Craft and Hawkins[14], depicts how pressure typically declines in solution-gas drive reservoirs. (Please note, the graph represents a typical solution-gas drive reservoir, the Kelly Snyder Field and is not calculated from any of the fields in the study area.) As this graph illustrates, reservoir pressure decreases as fluids are withdrawn (shown as *recovery in per cent*). The pressure decrease is most pronounced above the bubble point when gas remains in solution and fluid expansion is the dominant drive mechanism. This is because reservoir fluids are relatively incompressible and small changes in volume (Δv) translate into large changes in pressure (Δp). Pressure changes more gradually once pressure falls below the bubble point as expansion of the fluid is a combination of fluid expansion and increasing gas saturation. Since the Delaware Mountain group formations produce under a solution gas drive mechanism, average reservoir pressure decreases with time, provided total withdrawals exceed total injection.

A survey of the water injection and salt water disposal wells in the study area shows *almost all* injection is into the Delaware Mountain group. Hence if total fluid production (oil, gas, water) is a larger volume (at reservoir conditions) than total fluid injection (water) the average reservoir pressure has decreased with time. This assumes the injection is evenly distributed throughout the reservoir such that no area receives a disproportionate injection volume in relation to production. This assumption will, for now, be accepted, but will be shown later in this discussion to be correct. The accompanying graph (figure no. 8) shows the injection / withdraw ratio as a function of time for the Delaware Mountain Group.

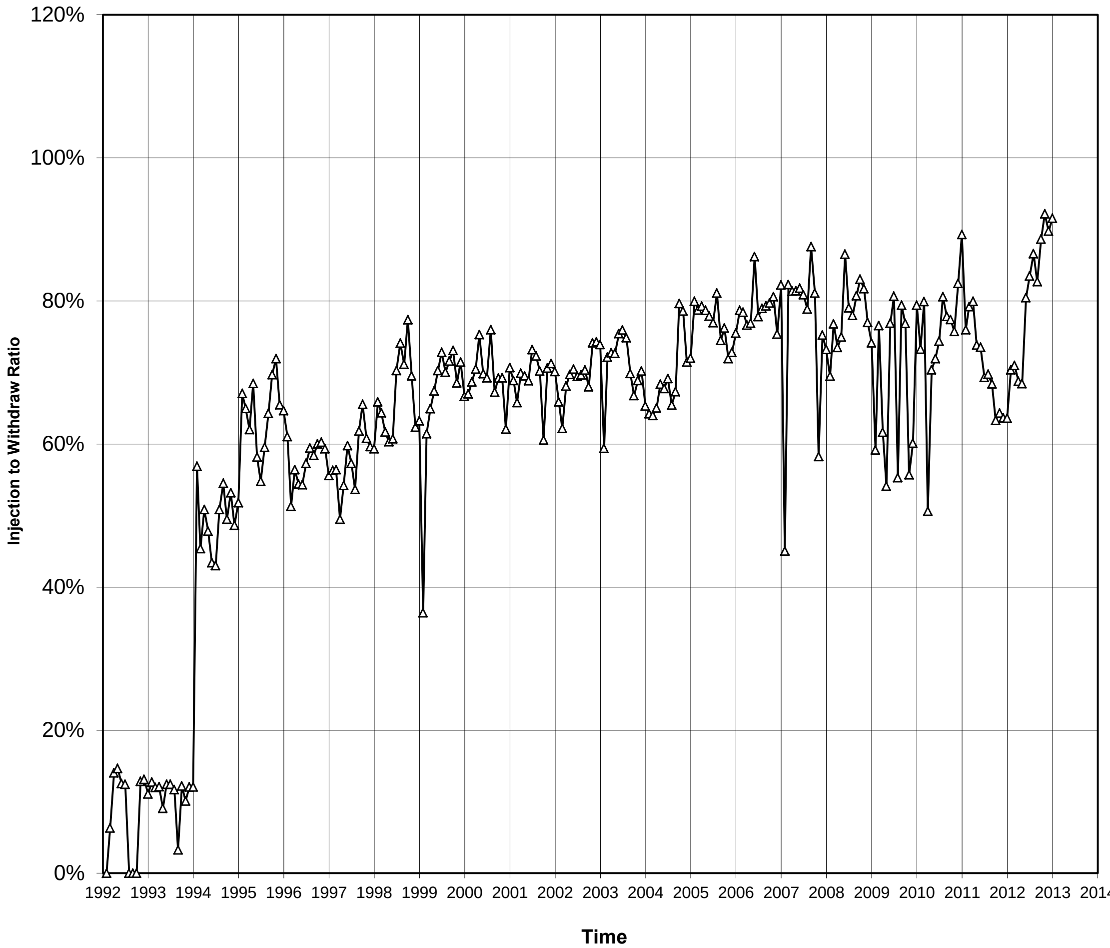

Figure no. 8 – Injection to Withdraw Ratio vs. Time in Study Area

This graph shows the injection to withdraw ratio, although gradually climbing, remains less than unity. Consequently, (1) withdraws continue to outpace injection, (2) reservoir voidage continues to increase and (3) reservoir pressure in the Delaware Mountain Group formations is declining. The current net voidage is approximately 156,000,000 reservoir barrels. If the present water injection rate of 2,400,000 barrels of water per month were to double, it would take approximately 2.5 years just to fill-up the current voidage. This calculation assumes production continues on the current decline trend.

When compared to the prior 2008 study, water injection is essentially the same at a 2012 average of 75,000 barrels of water per day versus 74,100 barrels of water per day during 2007.

The maximum volume of any injection well is 7,945 barrels of water per day for the Todd 36 State no. 1 in October 2012. This volume represents approximately 10 percent of the total volume injected in the study area. The section with the most injection is section 36 in 23S 31E with an average injection of 6,816 barrels of water per day into one well representing about 9.0 percent of the total. Twelve additional sections have average injection ranging from 6,280 barrels of water per day to 2,000 barrels of water per day. The thirteen sections with the highest injection volumes account for 55 percent of the total injection in the study area. These thirteen sections are scattered throughout the area, one is in township 21S 31E, one is in township 22S 31E, three are in township 22S 32E, one is in township 22S 30E, two are in township 23S 31E, two are in township 23S 31E, one is in township 21S 32E, and two are in 23S 30E. Consequently, injection is rather evenly distributed, with no single area receiving a disproportionate volume of water.

8.0 Data Acquisition

The data used herein consists primarily of two types of information, well volume data and well testing data. The well volumes of oil, gas, water and water injection were obtained from a combination of sources including the New Mexico Oil Conservation Division, New Mexico Oil & Gas Engineering Committee and *Lasser Production Data, Inc*. *Lasser* maintains a proprietary database derived from public records. Well test data were obtained from well files at the NMOCD office in Santa Fe, New Mexico and from the Risk Based Data Management System (RBDMS) database in the OCD District I office in Hobbs, New Mexico and the OCD District II office in Artesia, New Mexico. All data were obtained during May and June 2013 and include all data available through December 2012.

9.0 Conclusions

Based upon a study of both producing and injection wells in the nine township study area, we offer the following conclusions:

1. Ongoing development of oil and gas bearing reservoirs in the study area will continue throughout the next five years provided economic returns remain favorable (i.e. oil and gas prices and drilling costs remain comparable). Horizontal development accounts for nearly all new well drilling in the Delaware and Bone Spring formations. The rate of drilling for the Delaware Mountain Group (Cherry Canyon, Brushy Canyon) oil wells is projected at 40 to 60 wells per year. Pennsylvanian gas well completions in the Atoka and Morrow formations are not attractive at current gas prices. New SWD wells will be needed to handle the additional volumes of produced water from new oil and gas wells.

2. Improving commodity prices encourage additional drilling activity. If oil and gas prices remain relatively constant, the drilling rates suggested in conclusion no. 1 are reasonable. Should commodity prices drop, then fewer wells will likely be drilled. Conversely, should commodity prices rise, then drilling will likely proceed at a faster pace.

3. Strawn and Wolfcamp reservoirs alone offer poor economics. These reservoirs, however, are reasonable targets in existing wells as deeper Atoka and Morrow sands become depleted.

4. The depositional environments in this region of the Delaware Basin suggest small, discontinuous reservoirs. Well performance and geological interpretation further support the concept of compartmentalized reservoirs.

5. For the study area, water injection into the Delaware Mountain Group formations is principally a water disposal operation. Therefore water injection volumes are virtually the same as produced water volumes. Several significant factors, such as poor response to injection and lack of economic feasibility, are disincentives to waterflooding of the Delaware reservoirs. Therefore, the status quo should continue and any increases in water injection should simply mirror increases in water production.

6. NMOCD regulations governing the operation of SWD and injection wells appear to successfully control the injection pressures and

mechanical failures of said wells. Mechanical failure rates are low and water injection out of zone rarely occurs under these conditions. However, during the past five years, the NMOCD has experienced difficulty in consistently applying these regulations to schedule, monitor, and record MIT and BHT tests. We believe this represents a significant shortfall in the enforcement of the New Mexico regulations and should be corrected. Although it is beyond the scope of this report to identify improvements, we do observe the active injector well count in the study area has increased 14 percent in five years with virtually no change in staffing levels at the OCD District Offices.

7. Reservoir voidage in the Delaware Mountain Group formations continues to increase. Consequently average reservoir pressure is declining.

8. Mandated testing ensures that mechanical failure of tubing, packer or casing is routinely detected and repaired. Furthermore, operators observe the statutory maximum injection pressures, thereby preventing out-of-zone fracturing. Operators of SWD wells generally seek to maintain low injectivity pressure and thereby minimize pumping costs. Such preferred lower pressures further reduce the potential for fracturing and migration out-of-zone. As drilling increases so will the need to dispose increased volumes of produced waters. Careful and prudent operation of disposal wells, as well as consistent enforcement of the governing injection rules, are important to help insure the injected waters are retained in the intended zones.

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