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TECHNICAL SUPPORT DOCUMENT FOR

SECTION 194.32 AND 33: COMPLIANCE RECERTIFICATION APPLICATION RE-EVALUATION OF SELECT HUMAN INTRUSION ACTIVITIES

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Radiation and Indoor Air
Center for the Waste Isolation Pilot Plant
1301 L St. N.W.
Washington, DC 20005

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ACRONYM LIST

bbl	barrel
BHT	Bradenhead Test
BWPD	barrels of water per day
CCA	Compliance Certification Application
CCDFs	complementary cumulative distribution functions
CFR	Code of Federal Regulations
CMP	Compliance Monitoring Program
COMP	Compliance Monitoring Parameter
CRA	Compliance Recertification Application
DBDSD	Delaware Basin Drilling Surveillance Data
DOE	U.S. Department of Energy
DST	drill-stem tests
EPA	U.S. Environmental Protection Agency
EUR	estimated ultimate recovery
EXO	Enriched Xenon-136 Observatory
FEP	features, events, and processes
GENIUS	Germanium in Liquid Nitrogen Underground System
INPAC	Institute for Nuclear and Particle Astrophysics and Cosmology
LWA	Land Withdrawal Act
MIT	Mechanical Integrity Test
NMBMMR	New Mexico Bureau of Mines and Mineral Resources
NMOCD	New Mexico Oil Conservation Division
NORM	naturally occurring radioactive materials
NOW	non-hazardous oilfield wastes
OMNIS	Observatory for Multi-Flavor Neutrino Interactions from Supernovae
PA	Performance Assessment
PAVT	Performance Assessment Verification Test
ROP	rate of penetration
RTT	radioactive tracer test
SPR	Strategic Petroleum Reserve
SWD	salt water disposal
TA	temporarily abandoned
TSD	Technical Support Document
UBD	underbalanced drilling
WFL	water flow log
WIPP	Waste Isolation Pilot Plant

EXECUTIVE SUMMARY

The Waste Isolation Pilot Plant (WIPP) is located near the center of the WIPP Land Withdrawal Act (LWA) boundary, an area of approximately 16 square miles located in T22S, R31E, Eddy County, New Mexico. The U.S. Department of Energy (DOE) was required to determine and assess features, events, and processes (FEPs) associated with the WIPP and surrounding areas in its 1996 Compliance Certification Application (CCA), and to include selected FEPs in its performance assessment (PA) of the WIPP's ability to contain radioactive waste over a 10,000 year period. EPA is required to recertify that the WIPP continues to comply with EPA's radioactive waste disposal regulations every five years. As part of the each recertification, DOE must re-assess all FEPs, including human-related activities, that occur at or near the WIPP and determine if any new activities have developed, or whether any previously identified FEPs have changed to the extent that they may need to be reconsidered or considered differently in PA modeling.

The U.S. Environmental Protection Agency (EPA or Agency) re-evaluated select human-initiated FEPs as documented in the Compliance Recertification Application (CRA) with respect to drilling, injection activities, mineral extraction activities, and alternative uses of existing mines. The Agency's analysis included review of information provided with and as part of the CRA, as well as examination of readily available information concerning drilling, fluid injection, mineral extraction, and alternative mine uses in the WIPP area. The Agency's analysis did not identify any significant changes in drilling, fluid injection, or mining activities in the vicinity of WIPP, since the CCA, that would warrant reconsideration of FEPs and subsequent possible changes to PA models or input parameters other than those identified by DOE (e.g., DOE has tracked deep drilling rates and has modified the drilling rate accordingly in CRA documentation). Also, DOE has elected to revise human-intrusion related parameters, such as angular drilling velocity, etc., to be consistent with the Agency's Performance Assessment Verification Test (PAVT) values; these types of modifications appear appropriate.

EPA required DOE to change some CRA PA parameters and to rerun the CRA PA, the new PA is called the Performance Assessment Baseline Calculation or the PABC. DOE as part of the PABC implementation reevaluated the impact of EPA mandated changes on CRA FEPs. DOE determined that no changes were needed. EPA reviewed DOE reevaluation and agreed with DOE's conclusions (see EPA 2006, Docket A-98-49 Item II-B1-16, Section 2.0)

1.0 Summary of Review and Content of the Report

The Waste Isolation Pilot Plant (WIPP) is located near the center of the WIPP Land Withdrawal Act (LWA) boundary, an area of approximately 16 square miles located in T22S, R31E, Eddy County, New Mexico. DOE was required to determine and assess features, events, and processes (FEPs) associated with the WIPP and surrounding areas in its 1996 Compliance Certification Application (CCA), and to include selected FEPs in its performance assessment (PA) of the WIPP's ability to contain radioactive waste over a 10,000 year period.

Specifically, in 40 CFR §194.32, the Environmental Protection Agency (EPA, or Agency) required that the CCA assess the effects of human initiated activities, including excavation mining, drilling, fluid injection, and future development of leases. Additionally a requirement of 40 CFR§194.33 is that DOE must evaluate and document the effects of deep and shallow drilling on the disposal system in the PA. The original CCA also included the effects of current activities such as secondary oil recovery methods (waterflooding), disposal of produced natural brine, solution mining to extract brine, etc., in the vicinity of the repository. DOE identified the following human-initiated activities among those potentially present in the Delaware Basin near the WIPP, and addressed these FEPS in the original CCA:

- Oil and gas exploration/exploitation and extraction, including enhanced oil recovery.
- Potash exploration/exploitation (extraction is addressed under Section 194.32(b)).
- Fluid injection related to oil and gas production (Class 2).
- Sulfur coreholes.
- Hydrocarbon (gas) storage in geologic reservoirs.
- Gas reinjection.
- Brine wells for solution mining (salt water mining).
- Water supply wells.
- Potash mining.
- Other resource extraction activities.

DOE divided human-initiated activities into three categories: (1) those that are currently occurring, (2) those that might be initiated during the operational phase, and (3) those that might be initiated in the future after disposal. DOE concluded in the CCA that oil and gas exploration and exploitation and water and potash exploration are the principal human-initiated activities that need be considered for the PA; all other human-initiated activities were screened out (Chapter 6.2.5 of the CCA). The Agency, during its CCA review, examined DOE's categorization of human-initiated activities and concluded that the activities analyzed by DOE capture the spectrum of activities that would occur during the 10,000-year regulatory time period. EPA evaluated each of these FEPs, some in great detail (e.g., Technical Support Document V-B-22, Fluid Injection Analysis; Technical Support Document V-B-27, LWA Lease Evaluation; Technical Support Document V-B-29, Analysis of Air Drilling at WIPP; and Technical Support Document V-B-3, Section 194.14-Content of Compliance Certification Application). The Agency provided comments to DOE on human-initiated FEPs; DOE addressed EPA's concerns. In 1998, The Agency certified WIPP and WIPP began accepting waste in March of 1999.

According to the WIPP LWA, EPA must recertify whether or not DOE continues to comply with EPA's radioactive waste disposal regulations every five years, following the first receipt of waste

(1999). As part of the recertification, DOE must re-assess human-related activities that occur at or near the WIPP and determine if any new FEPs have arisen, or whether any previously identified FEPs have changed to the extent that they may need to be reconsidered or considered differently in PA modeling. Appendix PA Attachment SCR of the Compliance Recertification Application (CRA) list human related features, events, and processes assessed as part of the CRA, nearly all of which were also assessed as part of the CCA. The Agency re-evaluated select human-initiated FEPs documented in the CRA, and this Technical Support Document (TSD) discusses results of EPA's re-evaluation with respect to the following general categories:

- Human Intrusion by Drilling: Exploration, Completion, and Abandonment, which included activities to:
  - evaluate changes to drilling-related activities in the Delaware Basin to ensure air drilling assumptions have not changed since the original certification and still do not need to be included in the CRA PA,
  - verify that the new human intrusion rate has been updated and calculated correctly,
  - verify that stuck pipe and gas erosion assumptions and scenarios have not changed and do not need to be included in the CRA PA.

- Injection Activities, which included activities to:
  - reassess CO_2 injection and other forms of injection,
  - evaluate any changes in practices related to fluid injection for brine disposal and resource production enhancement, including changes to and impacts of injection rate and injection pressure.
  - verify that the Hartman assumptions and scenarios have not changed and do not need to be included in the CRA PA.

- Mineral Extraction Activities, including assessment of changes in mining practices, activities, etc.

- Alternative Uses of Existing Mines, such as gas storage.

The Agency's analysis described in this TSD does not address all human-activity related FEPs, for example archeological investigations and the effects of abandoned boreholes were not re-evaluated in this report. The Agency's review also did not revisit all of the data presented in the CRA and related references to ensure accuracy of each data point. Rather, the Agency evaluated the information presented by DOE and spot or cross checked selected information to confirm whether any changes in the specific human-activity FEPs occurred, thus warranting reconsideration in the CRA and, possibly, the CRA PA. (An update of OIL and GAS Productive Formations is discussed in Attachment A of this TSD.)

2.0 Evaluation of Selected Human Intrusion Scenarios Presented in the CRA

DOE included several intrusion scenarios in the CRA, all of which were included in the CCA and some of which were then addressed in both the CCA PA and CRA PA, as discussed in Section 2.1, below. Table 1 list those FEPs related to the human intrusion scenarios addressed in this TSD, including CRA modifications to those FEPs, if applicable. As shown in Table 1, some FEPs were included in the PA. Use of these FEPs in PA sometimes required the determination input parameters specific to human intrusion activities, such as drilling angular velocity, etc. Table 1 also documents parameters that resulted from Human Intrusion-related FEPs, including parameters included in the CCA PA and revision of these parameters for the CRA PA. More detailed information concerning some of these parameters is presented in Sections 2.1-2.4, below.

The Agency evaluated these intrusion activities by category: human intrusion by drilling, injection activities, mining activities, and alternative uses of mines and the results of this analysis are discussed in Sections 2.1 to 2.4. As indicated previously, our analysis involved: 1) re-examination of the CCA and related decisions and determinations; 2) review of the CRA and supporting documents, and 3) analysis of activities pertaining to each category to "ground truth" DOE's assertions. The purpose of our examination was not to repeat work performed as part of the Agency's CCA analysis, but to determine whether specified human intrusion scenarios have changed since the CCA and if so, whether the changes warranted revised consideration of the FEPs in the CRA or also required further review or modeling.

Table 1. FEP Changes in Screening and Parameters, CCA and CRA					
FEP No.	**Name**	**CCA Screening**	**CRA Screening**	**Resulting Parameters for CCA PA**	**Parameter Changes for CRA PA**
H1	Oil and Gas Exploration	SO-C (HCN) DP (future)	No change	*Deep drilling rate*	
				46.75	52.5
				Shallow drilling rate	
				21.81	23.102
				Drill string angular velocity	
				7.8 rad/sec	4.2-23 rad/sec
				Log permeability non-degraded cement	
				5 x 10^{-17} m^2	10^{-17} to $10^{-19}m^2$
				Log permeability of non-degraded cement sheath	
				2.24 x 10^{-14} m^2	not used in CRA
				Log permeability of fully degraded cement sheath	
				3.16 x 10^{-13} m^2	2.24 x 10^{-14} m^2
				Drill collar length, Drill collar diameter Drill pipe diameter	
				DCL: 1.83E+02 m DCD: 2.0E-01 m DPD: 1.14 E-01 m	Unchanged
					Drill Penetration rate
					4.45E-03 m/s
				ID of drill pipe	
				9.72 E +02 m	Unchanged
				Probability of hitting a Castile Brine pocket	
				.08	.01-.6
				Initial Castile brine pressure	
				1.11-1.7 E7 pascals	Unchanged
				Drilling Mud Parameters	
				brine density: viscosity: yield stress point:	1.21 E+03 kg/m3 9.17 E-03 Pa*s 4.40 E +00 Pa

Table 1. FEP Changes in Screening and Parameters, CCA and CRA (continued)					
FEP No.	**Name**	**CCA Screening**	**CRA Screening**	**Resulting Parameters for CCA PA**	**Parameter Changes for CRA PA**
H2	Potash Exploration	SO-C (HCN) DP (future)	No change	as above	as above
H4	Oil and Gas Exploitation	SO-C (HCN) DP (future)	No change	as above	as above
H8	Other Resources	SO-C (HCN) DP (future)	No change	none	None
H9	Enhanced Oil and Gas Recovery	SO-C (HCN) DP (future)	No change	see H1	see H1
H10	Liquid Waste Disposal	SO-R (HCN) SO-R (HCN)	No change	none	None
H11	Hydrocarbon Storage	SO-R (HCN) SO-R (HCN)	No change	none	None
H13	Conventional Underground Potash Mining	UP (HCN) DP (future)	Called Potash Mining in CCA; solution mining now in new FEPs H58 and H59. Screening not changed for conventional mining	See CARD 32	Footprint slightly modified but FEP re-analysis not required.
H14	Other Resources	SO-C (HCN) SO-R (future)	No change	none	None
H16	Construction of Underground Facilities	SO-R (HCN) SO-R (future)	No change	none	None

Table 1. FEP Changes in Screening and Parameters, CCA and CRA (continued)					
FEP No.	**Name**	**CCA Screening**	**CRA Screening**	**Resulting Parameters for CCA PA**	**Parameter Changes for CRA PA**
H25	Oil and Gas extraction	SO-C (HCN) SO-R (future)	No change	none	None
H27	Liquid Waste Disposal	SO-C (HCN) SO-R (Future)	SO-C (HCN) SO-C (future)	none	None
H28	Enhanced Oil and Gas Production	SO-C (HCN) SO-R (Future)	SO-C (HCN) SO-C (future)	none	None
H29	Hydrocarbon Storage	SO-C (HCN) SO-R (future)	SO-C (HCN) SO-C (future)	none	None
H58	Solution Mining for Potash	n/a	SO-R (HCN) SO- R (future)	n/a	None
H59	Solution Mining for other Resources	n/a	SO-C (HCN) SO-C (future)	n/a	None

Key:

SO-C Screened out due to consequence SO-R Screened out due to regulatory concerns

HCN historical, current, near future

Included in the performance assessment as: UP - Undisturbed Performance or DP - Disturbed Performance

2.1 Human Intrusion by Drilling: Exploitation, Completion, and Abandonment

Human-initiated activities related to drilling included three different drilling-related intrusion scenarios used in the PA, designated by DOE as E1, E2 and E1E2 (CCA Chapter 6, Section 6.3.2.2). The E1 scenario assumed penetration of a panel by a borehole drilled through the repository, which then strikes a brine pocket present in the underlying Castile Formation. The E2 scenario included all future boreholes that penetrate a panel but do not strike a brine pocket in the Castile Formation. The E1E2 scenario was defined as the occurrence of multiple boreholes that intersected a single waste panel, with at least one of the boreholes being an E1 occurrence. The drilling scenarios considered in the CRA are the same as those considered in the CCA. Refer to Section 194.33(a) in the Agency's CCA document entitled *CARD 33—Consideration of Drilling Events in Performance Assessments* (EPA, 1998d) for additional discussion of the three different drilling-related intrusion scenarios.

2.1.1 Background: CCA Results and EPA's CCA Conclusions

Drilling practices and activities were examined in the CCA to assess these intrusion scenarios and to determine drilling rates (shallow and deep) and other drilling-related information related to PA (see Table 1). The DOE concluded that drilling for resources such as oil and gas outside the LWA area would have little impact on the WIPP in the near term and, therefore, DOE was not required to examine the effects of such drilling in the more distant future as per 40 CFR §194.25(a). However, the DOE included drilling for resources within the LWA penetrating the repository in the CCA PA.

Drilling was incorporated in the CCA PA as a single event or combination of events based upon the above E1, E2, E1E2 scenarios. Drilling rates and activities are key to the calculation of releases, which are represented as complementary cumulative distribution functions (CCDFs). Deep and shallow drilling rates and related activities directly affect the cumulative potential for contaminant releases to the surface or to subsurface geologic units. Deep drilling is defined as drilling events in the Delaware Basin that reach or exceed a depth of 2,150 feet (655 meters), while shallow drilling refers to drilling depths of less than 2,150 feet (655 meters) (40 CFR §194.2). Both types of drilling events include exploratory and development wells. The deep drilling rate was defined as the sum of the rates of deep drilling for each resource in the Delaware Basin over the past 100 years. The shallow drilling rate was defined as the sum of the rates of shallow drilling over the same time period for each resource in the Delaware Basin that is of similar type and quality as the resources in the WIPP controlled area. For the CCA PA, DOE assumed constant drilling rates for estimating the number of boreholes for the next 10,000 years.

DOE calculated a CCA deep drilling rate of 46.765 deep boreholes per square kilometer (0.39 square mile) over 10,000 years; DOE also calculated a CCA shallow drilling rate of 21.821 shallow boreholes per square kilometer (0.39 square mile) over 10,000 years (Table DEL-7). DOE excluded sulphur boreholes in the calculation of shallow drilling rate because no economically extractable sulphur is located within the WIPP LWA (NMBMMR 1995). DOE also excluded both shallow and deep boreholes drilled as part of WIPP site characterization efforts (DEL-7.4).

DOE stated that drilling in the near future within the Delaware Basin will most likely be for oil and gas exploration/exploitation, which constitutes a deep drilling event. Shallow drilling may occur for other resources (e.g., water, potash, and sulphur), but DOE concluded that future shallow drilling events were of low consequence to the performance assessment calculations. Therefore, only deep drilling events could result in inadvertent human intrusion into the WIPP repository (EPA, 1998d and CCA Appendix DEL-7) and need be considered. DOE identified the following drilling-related activities as being present in the Delaware Basin and potentially near the WIPP (CCA Appendix DEL.5, Tables DEL-3 through DEL-7):

- Oil/gas exploration/exploitation and extraction, including enhanced oil recovery (shallow and deep drilling).
- Potash exploration/exploitation (shallow and deep drilling).
- Fluid injection related to oil/gas production (deep drilling).
- Sulphur coreholes (deep and shallow drilling).
- Hydrocarbon (gas) storage in geologic reservoirs, gas reinjection (deep drilling).
- Brine wells for solution mining (shallow drilling).
- Water supply wells (shallow drilling).
- Geothermal resources (deep drilling).

The Agency examined the CCA to determine if DOE sufficiently evaluated deep and shallow drilling practices in the Delaware Basin and identified representative drilling methodologies. The Agency reviewed the information presented by DOE in CCA Chapter 6.2, Appendix DEL, and Chapter IX of NMBMMR (1995) to determine how extensively deep drilling and shallow drilling was considered and whether the information provided was sufficiently comprehensive, accurate, and correctly calculated. The Agency examined the list of references presented in the CCA relative to drilling (e.g. CCA References #230, #357, #664, and #667; DOE, 1995) and conducted a literature search for the purpose of evaluating the fluid injection study (EPA 1998a). EPA determined that DOE's scrutiny of resources to assess deep and shallow drilling practices and frequencies was comprehensive. Refer to Section 194.32(a) and (c) in *CARD 32—Scope of Performance Assessments* (EPA, 1998e) for additional discussion of resource assessments. The Agency also determined that DOE's conclusions regarding representative drilling methodologies in the Delaware Basin were consistent with available data, and the Agency discussed DOE's treatment of abandoned borehole properties and borehole plugging in Sections 194.33(c)(1) and (c)(2) of *CARD 33- Consideration of Drilling Events in Performance Assessments* (EPA, 1998d). Figure 1 illustrates a typical drilling rig that may be used in the Carlsbad area.

DOE did not identify air drilling as a current practice in the Delaware Basin and therefore did not include it in the CCA PA. DOE indicated that modern rotary drilling techniques, with a variety of mud systems, have been used to drill wells in the vicinity of WIPP (CCA Appendix DEL 5.1). The use of mud as the drilling fluid was the "current practice" for drilling through the salt section (the Salado and Castile Formations), and air drilling through the salt section was not consistent with current drilling practices in the Delaware Basin. Thus, DOE excluded air drilling through the salt section from consideration in the WIPP CCA PA.

DOE indicated that deep wells in the area near the WIPP site range from 5,000 to 15,400 feet deep, depending on the hydrocarbon-producing formation targeted. Standard completion technology included hydraulic fracture treatment of perforated long string casing using a variety of gelled fluids to emplace sand proppant into the fractures. DOE indicated that acid treatments and acid fracture treatments are frequently used and assumed that all oil- and gas-related boreholes in the area will be plugged according to current applicable regulations. CCA Appendix DEL.6.2.3 (p. DEL-71) discussed post-1988 boreholes declared shut-in or temporarily abandoned that have been plugged. This is consistent with data indicating that 100 percent of the wells drilled since 1988 were plugged or are in the process of being plugged to meet standards (Appendix MASS). The Agency examined the air drilling issue from several perspectives and documented its findings in the CCA TSD *EPA's Analysis of Air Drilling at WIPP* (EPA 1998b) and in CCA Response to Comments, Section 8 (Docket A-93-02, V-C-1). The results of EPA's analysis showed that air drilling is not current practice in the Delaware Basin through the salt section.


1. Drilling Rig, New Mexico. *Courtesy of Northstar Drilling*.

2.1.2 CRA Modifications

As a result of The Agency's CCA review, several human-related activities required tracking by DOE to ensure continued compliance of the program with baseline elements developed as part of the CCA. The program to track this information is called the Compliance Monitoring Program (CMP). DOE continued to maintain its Delaware Basin Drilling Surveillance Program (DBDSP), results of which are fed into the overall CMP. For example, information from the DBDSP is used to determine shallow and deep borehole drilling rates in and around the WIPP, and to monitor drilling-related activities to ensure that PA-related assumptions and activities remain valid. Since approval of the CCA, DOE has published four Delaware Basin Monitoring Annual Reports (DOE, 2002b), that focus on Compliance Monitoring Parameters (COMPs), parameters DOE is required by the Agency to track and assess that were identified through PA and sensitivity analysis during the EPA CCA review (CRA Appendix Data-10.0 and CRA Appendix MON-2.0). COMPs related to human intrusion that are tracked are the probability of encountering a Castile brine reservoir and the drilling rate.

In addition to monitoring the broader COMPs of drilling rate and Castile brine encounters, the Delaware Basin Drilling Surveillance Program also tracks several drilling-related parameters and data that were also included in the CCA PA analysis. CRA Appendix Data, Attachment A (DOE, 2004) provides a summary discussion of these specific drilling-related activities that have been tracked following certification; note that while this Attachment is entitled Delaware Basin Drilling Surveillance Data, it also includes borehole plug-related parameters/data, enhanced oil recovery data (i.e. CO_2 flooding), solution mining data, and conventional mining data as discussed in Sections 2.2 to 2.4 of this report. The activities monitored under the Delaware Basin Drilling Surveillance Program during the first recertification period include (CRA Appendix DATA, Attachment A):

- Drilling-related parameters and data such as drilling rate, drill bit diameter, etc.
- Castile brine-related parameters/data.
- Borehole plug-related parameters/data.
- Enhanced recovery data.
- Gas storage data.
- Solution mining data.
- Potash mining data.
- Seismic data.

2.1.2.1 Shallow and Deep Drilling and Human Intrusion Drilling Rate

DOE evaluated this information to determine changes in human-initiated parameters, assumptions, etc., related to drilling that should be reflected or discussed in the CRA. DOE concluded (CRA Appendix DATA, Attachment A and Section 6.0.2.3) that the drilling rate had increased from the 46.8 assumed in the CCA to 52.5 boreholes per square kilometer over 10,000 years. This was calculated based upon the number of deep holes installed from 1903-2002 (12,139) multiplied by 10,000 years, then divided by the Delaware Basin Surface Area (23,102.1km2)/100 years. DOE indicated that this value is expected to rise for quite a few more years before it begins to drop, due to the 100 year time-frame used for assessing the drilling results. DOE indicates that wells greater than 100 years old are progressively dropped from the active borehole value, and that it will be the year 2011 before any wells are dropped from the count.

2.1.2.2 Drilling Practices, Including Air Drilling

DOE tracks drilling-related parameters, including bit size used to drill the boreholes with respect to the location within the borehole (i.e., surface, intermediate, and production portions of the hole), because the bit diameter used to drill the hole may vary with depth. Most wells installed since the CCA were drilled using a three "string" hole (i.e. surface, intermediate, and production levels), with the surface hole drilled using either a 17 ½ or 14 ¾ inch diameter bit, the intermediate portion of the hole drilled using a 12 ¼ to 9 ⅞ inch diameter bit, and the production portion of the hole installed using a 7 ⅞ or 6 ¾ inch bit. Casing size for wells installed since the CCA in a "three string" hole ranged from 13 ¼ inch to 10 ¾ inch diameter surface casing, 8 ⅝ to 7 ⅝ inch diameter intermediate casing, and about 5 ½ to 4 ½ inch diameter production casing. Also, DOE tracks the drilling rotation speed, penetration rate, and other drilling factors; this information is important to PA because in a rotary drilling operation, the volume of material brought to the surface via cuttings and cavings is affected by the diameter of the drill bit, penetration rate, etc.

DOE concluded that the drilling rotation speed, penetration rate, drill collar/pipe diameter characteristics, etc. have not changed dramatically in the 1997-2002 time period. However, DOE elected to use a different drilling angular velocity value in the CRA than used in the CCA. In the CCA, DOE used an angular velocity of 7.8 radians/second. However, the Agency found it more appropriate to treat the drill string angular velocity as a sampled variable with a minimum of 4.2 radians/second, maximum of 23 radians/second and median of 7.77 radians/second. DOE has adopted the Agency's approach in the CRA (CRA Chapter 6 Table 6-1 and Appendix PA, Attachment PAR). DOE identified a drill bit diameter of 12 ¼ inches (.311 m) in the CCA, and DOE concluded in CRA Appendix Data Attachment A, Section DATA-A-5.1 that "currently, an 11 inch bit diameter would be used to drill the same depth as the repository", however, for the CRA PA DOE continued to use 12.25 inches. DOE also tracks information such as drilling rotation speed, penetration rate, length of drilling collar (pipe), etc. (DOE, 2004; DOE 1997a).

With respect to air drilling, DOE indicated in the CRA Appendix DATA Attachment A that a single well, the Sheep Draw "28" Federal #13 was installed using air drilling for the first 358 feet. No other instances of air drilling were identified by DOE. DOE did not address air drilling in documentation other than CRA Appendix DATA Attachment A, Table DATA-A-6 Air Drilled Wells, which showed the above described single incidence of air drilling that took place near the Carlsbad airport, indicating that only a portion of the hole above the salt section was air drilled. Therefore, the conditions assumed in the CCA remain valid and DOE determined it unnecessary to consider air drilling in the CRA PA.

2.1.2.3 Completion Practices and Abandonment Practices

DOE also tracked the well plugging and abandonment information obtained from July 1995-September 2002. Information tracked including the number of plugs (varies between 4-7), plug length, number of sacks of cement used to create each plug and cement type, and the type of steel alloy at different levels in the hole. In the CRA, DOE modified its CCA assumptions pertaining to permeability of concrete plugs and lower borehole permeability to represent lower borehole permeabilities endorsed by the Agency in its CCA Parameter Justification Report (EPA, 1998f), wherein the permeability of concrete plugs ranged from 1 x 10^{-17} to 1 x 10^{-19} m^2 (CRA Chapter 6, Table 6-1).

2.1.2.4 Castile Brine Pocket Occurrence

DOE identified 27 brine pocket occurrences prior to 1992, and this information was used in the CCA. Between July 1995 and September 2002, DOE noted an additional five Castile brine encounters identified during deep drilling. CRA Appendix DATA, Attachment A, Table DATA-A-2 list presents these encounters, which showed brine flow rates varying between 105 to 1000 barrels/hour. DOE stated that "no official documentation of New Mexico state records exists for the five new Castile brine encounters," four were discovered during discussions with drillers and the fifth was reported by one of the operators on an Annual Survey performed under the Delaware Basin Survey. DOE noted that all five encounters occurred in areas where Castile Brine had previously been encountered during drilling, with three of the wells in the vicinity of well #ERDA-6 and the other two southwest of the WIPP site. All were within the nine-township area surrounding WIPP.

2.1.3 EPA's Updated CRA Analysis

The Agency evaluated the information discussed in the CRA with respect to changes in drilling-related practices. Additionally, the Agency performed an independent analysis of the drilling practices and activities that were identified in the CRA to assess whether new practices were being used, to determine whether existing practices have changed since the CCA was submitted, and to determine whether these changes might warrant reconsideration of related FEPs under the CRA.

2.1.3.1 Shallow and Deep Drilling

The Agency examined the CRA and related references (e.g. DOE 1997a, DOE 2002a, SNL 2002b) to determine whether the presentation of shallow and deep drilling information in the CRA is technically adequate. Additionally, to facilitate the Agency's review, DOE provided preliminary data used to develop summary tables within the CRA, including the DOE's September 2002 Delaware Basin Drilling Surveillance Data (DBDSD). Information from these data tables was used to develop the Annual Compliance Monitoring Assessment for 2002 (DOE 2002c) and the Delaware Basin Monitoring Annual Report for 2002 (DOE 2002d). These data showed a total of 5,839 shallow boreholes (excluding core holes for WIPP site characterization) in the Delaware Basin, an increase of 303 wells, or 5.2%, from the 5,536 shallow boreholes used in the CCA (CCA Appendix DEL, Table DEL-4). About 65% of the new shallow boreholes were drilled for water, potash, and sulphur, and 13% for hydrocarbons. The corresponding percentages of shallow well counts for the CCA were 67% and 11%, respectively. With respect to deep drilling, DBDSD (excluding core holes for WIPP site characterization) reports a total of 12,128 boreholes (10,804 deep boreholes were presented in the CCA, Table DEL-4), which represents 1,324 new deep boreholes (10.9% increase since the CCA). More than 98.6% of the new deep boreholes are hydrocarbon boreholes (98.5% for the CCA), the remainder being sulphur, potash, and stratigraphic test boreholes.

The 1324 new deep boreholes installed since the CCA were from 5,000 to 15,400 feet deep; these depths are consistent with those of boreholes installed prior to the CCA. In addition, there is no evidence that current mud-based drilling technologies and practices are significantly different than those implemented prior to approval of the CCA. Therefore, the Agency concludes that since the shallow and deep drilling depths and target reserves in wells installed since the CCA are consistent with those presented in the CCA, no updated analysis is necessary regarding shallow and deep drilling activities and methodologies.

The Agency compared drilling activities as presented in the CCA with those included in DBDSD with respect to percentage change and by resources. The Agency's analysis showed no significant changes in shallow and deep drilling activities within the Delaware Basin since approval of the CCA. The CRA trends of shallow and deep drilling for water, potash, sulphur, and hydrocarbon resources within the Delaware Basin remain consistent with drilling trends for the CCA.

2.1.3.2 Human Intrusion Drilling Rate

The CRA (DOE, 2004) and related references indicate that the calculated deep drilling rate used in the CRA PA is the 2002 drilling rate of about 52.5 boreholes per square kilometers over 10,000 years while the shallow drilling rate presented in the CRA is the about the same as that presented in the CCA, i.e., 22 boreholes/square kilometer. The Agency re-examined these calculations using well counts from DOE's DBDSD, and confirmed that the current calculated deep drilling rate is approximately this value (i.e. calculated value is 52.497 boreholes per square kilometer over 10,000 years, and shallow drilling rate is 23.102 boreholes per square kilometer over 10,000 years). The CCA deep drilling rate was 46.765 boreholes per square kilometer, while the CCA shallow drilling rate was 21.821 boreholes per square kilometer. The number of holes per square kilometer was calculated as follows: (number of holes) x 10,000 years / area (= 23,102.1 square kilometers) / 100 years. As mentioned previously, only deep drilling events could result in inadvertent human intrusion into the WIPP repository (EPA, 1998d and DEL-7); therefore, the Agency only revisited, in depth, deep drilling rates in this analysis. It must be noted that the DOE 's Delaware Basin Monitoring Annual Report (DOE 2002d) indicated a slightly higher 2002 drilling rate than used in the CRA. DOE (2002d) indicated that the deep drilling rate for 2002 was 52.9 rather than 52.5. DOE did not explain the reason for this difference, as both the CRA and DOE (2002d) data cut off was September 2002. Based on available data, the 52.9 value appears to be most recent.

The new deep drilling rate is about 12.3% higher than that used in the CCA. This increase, however, was expected by the Agency and is consistent with public comments on the CCA (Response to Comments, Section 8.K, Docket A-93-02, V-C-1). Although the new deep drilling rate is much less than those suggested in the public comments (90 boreholes per square kilometer per 10,000 years suggested by SRIC or 30 times greater than the rate used in the CCA suggested by EEG), the 2002 deep drilling rate is still higher than that used in the CCA, i.e. 46.765 boreholes per square kilometer over 10,000 years.

To complete our reassessment of the significance of this drilling rate increase, we revisited the Agency's analysis regarding future deep drilling rates is presented in the Response to Comments, Section 8.K, Docket A-93-02, V-C-1. This analysis suggested that the original deep drilling rate of 46.765 is a reasonable and likely very conservative estimate of future drilling rates, considering that the value is applied for 10,000 years, no one resource will last for the entire 10,000-year regulatory time frame (for example: drilling for oil and gas is expected to last for 100 to 150 years) and the resources targeted by drilling today may not be the same as those drilled in the future. As such, the Agency expected that the deep drilling rate would rise for a few more years before it began to drop, because of the 100-year time frame used with respect to consideration of drilling results (i.e., as new wells are added to the count, wells older than 100 years are dropped). Therefore, the 2002 increase in drilling rate was expected, and may not be the peak drilling rate for the resources available today. The average drilling rate for the same resources in the future is expected to decline (due to limited resources) and should ultimately be lower than the present drilling rate. Because drilling is expected to peak and trough, this suggests that the original 47.765 deep boreholes per square kilometer over 10,000 years is actually a conservative assumption, so the CRA drilling rate of 52.5 drilling rate could be considered even more conservative.

2.1.3.3 Drilling Practices, Including Air Drilling

The Agency examined drilling survey information in DBDSD (DOE 2004). This information showed that all new wells were drilled using rotary drilling techniques with mud as a drilling fluid, except for one oil well (Sheep Draw "28" Federal #13) that was partially air drilled the first 358 feet, in July 1997. We confirmed that the majority of the new deep wells were drilled with a three-string casing program, which includes surface casing (typically a 13 ⅜ inch inner diameter casing to isolate the borehole from uppermost water-bearing units), intermediate casing (typically a 8 ⅝ inch inner diameter casing for the borehole through the salt-bearing units where the WIPP is located), and production casing (typically a 5 ½ inch inner diameter casing is installed down to the interval where the oil and/or gas occurs, below the salt beds). Our review of available data does not indicate changes to general drill collar length/diameter, drill penetration rate and drill pipe diameter that would warrant reconsideration of FEPs related to these parameters that were reflected in PA. DOE elected to revise the drill string angular velocity to be consistent with that used in the PAVT.

In addition to the above parameters, DOE also included drilling-mud related parameters in its spallings model activities. These parameters include drilling mud pump rate, initial drilling mud density, initial drilling mud viscosity, drilling muds slurry maximum solids volume fraction, drilling mud slurry solids viscosity exponent. Values for most of these parameters were not included in the database material reviewed as part of this TSD analysis. Also, there is no evidence that the current drilling technologies and trends using alternative drilling practices, such as directional drilling, have been implemented. Therefore, it appears that current drilling practices are not significantly different from those implemented prior to the CCA.

The Agency also performed analysis of air drilling occurrences in the Delaware Basin since the CCA. We note that although the use of air drilling (underbalanced drilling, or UBD, techniques) is very limited in the Delaware Basin historically (it is only used in specific localized limited stratigraphic intervals to overcome lost circulation problems), UBD could offer advantages in some situations, including:

- Drilling into or through formations subject to impairment, particularly naturally fractured reservoirs drilled with straight hole or horizontal laterals.
- Drilling to deeper reservoirs below depleted or underpressured zones, as these zones can cause severe drilling problems such as lost circulation and stuck drillpipe.
- Drilling gas storage wells, where minimized formation damage is essential to guarantee adequate on-demand deliverability.
- Drilling producing water or other disposal wells, particularly where hydraulic fracturing is environmentally unacceptable.
- Any situation where ROP (rate of penetration) can be economically increased and fewer bits are used.

Some of the above situations may be applicable in the Delaware Basin, where UBD could be used, for example, for drilling problems related to stuck pipe and lost circulation. However, available data indicate that, consistent with the CCA, air drilling does not currently appear to be used in the Delaware Basin through the salt section in which WIPP is located.

The Agency also examined recent advances in drilling technologies and oil and gas exploitation and production practices to determine whether any of these could have taken place in the WIPP area since the CCA. In other oil and gas producing areas, including areas in the Delaware Basin but outside of the WIPP area, these advances have made oil and gas production feasible in fields that were previously considered marginal, where the oil and gas resources were located in complex reservoirs, and/or in frontier or challenging environments. Advances in drilling technology are having a greater impact on reservoir production rates and recovery factors than any other technology advance in the exploitation of oil and gas. For example, advances in horizontal and directional well drilling, and the use of extended reach and multi-laterals, coupled with slim-hole and smart/intelligent well completions have greatly advanced the economics of oil and gas production on a global basis. Figure 2 provides an example case history of a successful horizontal drilling venture in the west Texas portion of the Delaware Basin (Montgomery et. al., 2000).

> Beginning in 1996, Texaco and IP petroleum launched an important and largely successful effort to establish improved Cherry Canyon production from horizontal wellbores. This activity has been concentrated in the War-Wink East field of West Texas. The rationale for using horizontal drilling in the Cherry Canyon was to expose more of the higher quality reservoir to the wellbore and to reduce water production.
>
> Between 1996 and 1997, Texaco completed four wells in the southern half of Section 40, Block 21, University Lands Survey, flowing at rates of 250-650 bbl and 250-600 mcf per day. Several subsequent horizontal attempts in the northern half of the section had only minor success, apparently due to pinch-out of the relevant sandstone. Two attempts by IP Petroleum in the northwestern portion of Section 45, targeted in the same channel, have had significant production and further confirm the selective use of this approach. A notable improvement has been the considerable decrease in water production associated with these wells in comparison with stimulated vertical producers.
>
> Laterals for all of these wells are on the order of 1,400 - 2,000 feet in length. At these lengths, unstimulated horizontal wells are roughly equal to or less in cost than stimulated vertical wells. Increased oil and decreased water production thus make horizontal drilling an economically attractive approach to developing Cherry Canyon production in War-Wink and possibly elsewhere in the Delaware Basin.

Figure 2. Horizontal Drilling in War-Wink Area of West Texas - Delaware Basin.

The Agency also notes that the cost of technology capture and application (i.e., use of innovative technologies) is no longer reserved just for integrated major oil companies, but is also within the reach of smaller independent oil companies. Related advances in coiled tubing applications and fracturing technologies coupled with 4D seismic and real-time data acquisition are also providing enormous benefits to the operators. The Agency, however, has determined that at the present time, the application of these innovative technologies, such as horizontal, extended reach, or multilateral drilling is absent in the vicinity of the WIPP area of the Delaware Basin. Therefore, consideration of these technologies in the CRA is not warranted at this time. However, the Agency will track these technologies to determine whether future recertifications will require consideration of any of these technologies, taking into account the fact that most of the oil and gas reservoirs in the Delaware Basin are discontinuous and compartmentalized, therefore many of these new technologies may not work near WIPP. The Agency believes that even if these technologies were used in the WIPP vicinity, based on available information, they likely would not detrimentally impact the repository.

The Agency also examined whether reported instances of "stuck pipe" or related gas occurrences had changed since the CCA as report in the CRA. No information was included in the CRA which led to modifications of conclusions regarding the occurrence and management of "stuck pipe" issues.

2.1.3.4 Completion Practices and Abandonment Practices

The Agency also performed a literature search (e.g., Montgomery 1999, 2000) to assess the impact of completion practices on oil and gas production, and to determine whether any advances in this area have occurred in the Delaware Basin. Our analysis indicated that wells productive from the lower part of the Cherry Canyon Formation (Delaware Mountain Group) yield oil and gas at higher rates than has been typical for the upper part of the formation, and these high production rates are a result of a combination of good-quality reservoir and improved completion practices. In the past, fracture treatments of Cherry Creek wells were relatively large in size (up to 300,000 lb proppant) and were run at steady pump rates, often as high as 40 bbl/minute. This approach caused vertical propagation of stimulated fractures into wet zones, resulting in considerable water production with the oil and gas extraction. More recently, however, operators have modified their completion approach to smaller size designs using less overall proppant delivered at a progressively increased, but initially low, pump rate. This "ramprate" approach, using staged increases in both pump rate and proppant concentrations, has proven quite successful in reducing water production and increasing oil recovery. The Agency recognizes that while this activity is different from that which occurred prior to approval of the CCA, the resulting change has reduced the possibility of overt fracturing and does not warrant any changes in PA-related considerations.

The Agency examined information in the CRA, references provided by DOE and concludes that well/borehole completion technologies and practices for the new wells drilled in the Delaware Basin since approval of the CCA are consistent with the completion practice prior to the CCA. Regulations regarding plugging the shut-in or abandoned wells have not changed since the CCA. Plugged well information in the recent DBDSD shows that the shut-in and abandoned wells after the CCA were plugged solid with cement. The plugging requirement and procedure are consistent with the assumptions used in the PA. Refer to Table 1 for changes in parameter values related to cement sheaths.

2.1.3.5 Castile Brine Pocket Occurrence

EPA examined the Castile data assembled by DOE, and did not find that this specific information requires revision of FEPs related to the two Castile-specific elements examined in this TSD, i.e., probability of hitting a Castile brine pocket, and initial Castile brine pressure. The brine occurrences were discovered by DOE upon interview with basin operators rather than

NMOCD documentation thereof, and pressure data were not included in reviewed information. Also, DOE elected to use the PAVT probability of hitting a Castile brine pocket during drilling.

2.1.4 Conclusions

The Agency's analysis of shallow and deep drilling activities within the Delaware Basin found that current drilling activities remain consistent with those included in the original CCA. No updated analysis regarding shallow and deep drilling activities is necessary at this time, and no modification to PA assumptions appears warranted.

The Agency notes that the current deep drilling rate is 52.497 boreholes per square kilometers over 10,000 years, which is higher than that used in the CCA (the number was 46.765 for the CCA). This increase is expected and the drilling rate is anticipated to rise for a few more years before it begins to drop due to resource limits. In the future, its value is expected to drop lower than it is today. This suggests that DOE's CCA drilling rate of 46.765 was already a conservative assumption, so the 2002 drilling rate of 52.5 is even more conservative.

There is no evidence that the current drilling technologies and trends in directional drilling practice are different from those implemented prior to the CCA. Rotary drilling with mud is still the common practice in the Delaware Basin, with all the wells drilled being vertical or straight holes. This type of drilling technology is consistent with the assumptions used in the CCA. Further, the use of air drilling in the Delaware Basin has not changed since the last certification as it is not currently practiced while drilling through the salt section. Operators periodically use air to drill through a prospective productive section to protect it and to drill through problem intervals, but its use continues to not be widespread, as was concluded in the CCA. Finally, current completion technology and regulations regarding well abandonment have not changed since the CCA. Therefore, few drilling-related changes have occurred in the WIPP area of the Delaware Basin since the CCA approval, and those that have occurred (i.e. deep drilling rate, angular velocity, etc) appear to have been recognized in the CRA.

2.2 Borehole Injection Activities

Borehole injection activities in the Delaware Basin include those for disposal of wastes generated through oil and gas production, injection activities to enhance existing production, and the injection of other waste material. Injection activities as addressed in the CCA and evaluated by the Agency are presented, followed by new CRA information and EPA's subsequent re-analysis.

2.2.1 Background: CCA Results and EPA's CCA Conclusions

In the CCA, DOE stated that in the WIPP vicinity, current oil and gas operations include conversion of selected depleted production wells into brine disposal wells or waterflood injection wells for secondary recovery. Brine disposal was typically into the Bell Canyon Formation.

Based on observed porous intervals across the subject leases, and the industry practice of well conversion for brine injection, DOE indicated that it is likely that a field operator may, upon depletion of reserves, convert a well that has been producing from the Bell Canyon or another zone into a brine disposal well for disposal of oil field brines. It is also likely that secondary recovery efforts in Los Medano Field, near WIPP, may include conversion of depleted wells into injection wells to enhance oil and/or gas recovery efforts. DOE evaluated the potential impact of injection activities immediately outside of the LWA area and concluded that such activities would have little if any impact on the disposal performance of WIPP, based upon geologic containment characteristics of the WIPP site, well completion practices in the WIPP area, etc. DOE therefore screened fluid injection and secondary oil/gas recovery from the CCA performance assessment based on low consequence. EPA evaluated this data during our CCA review, and posed questions which resulted in additional study and analysis by DOE (i.e. Stoelzel and Swift, 1997). EPA (1998a) independently evaluated the impact of fluid injection on repository performance. The study confirmed the relatively favorable site characteristics and well completion practices, and concluded that it is highly unlikely that the combination of events and site characteristics, necessary for a worst-case injection scenario to occur, would be present in the WIPP area. EPA therefore concurred with DOE's decision to exclude fluid injection from performance assessment.

2.2.1.1 Fluid Injection/Enhanced Recovery and Brine Disposal as Addressed in CCA Analysis

At the time of the CCA, probable oil and gas condensate resources within the WIPP bondary were estimated to be 12.3 million barrels for primary production and an additional 6.4 million barrels from secondary recovery (DOE 1995). Gas reserves were estimated to be 186 billion cubic feet, with the majority of production coming from Pennsylvanian-age formations (Morrow, Atoka and Strawn). Approximately twice this amount of recovery was estimated to be probable if this area were increased to include all land within one mile of the LWA boundary. Assuming that economic conditions remain similar to the present, DOE concluded, and the Agency agreed, that it was very likely that oil and gas production activities will continue for a minimum of several decades. Also, injection of produced brines will be required over the lifetime of oil production in the area.

As part of the CCA review, the Agency examined fluid injection in-depth in its TSD entitled *Technical Support Document for Section 194.32: Fluid Injection Analysis (V-B-22)* (EPA 1998a). The purpose of the report was to evaluate the potential for fluid injection activities in the vicinity of the WIPP site to significantly affect the WIPP disposal system. In support of this objective, the Agency reviewed publicly available documents and DOE's fluid injection screening activities performed to support PA. In addition, the Agency developed estimates of the probability that a failed injection well could significantly impact WIPP repository performance. The Agency found that fluid injection is a current practice in the vicinity of WIPP that can be expected to continue into the near future, and was being conducted for purposes that can include brine disposal, oilfield pressure maintenance, and oilfield waterflooding. The Agency also determined that the consequence of fluid injection on WIPP repository performance is likely to be low because the geologic conditions and the well construction and operational standards in the vicinity of WIPP mitigate both a catastrophic injection well failure and the movement of excess brine into the WIPP repository should such a failure occur. The Agency recognized that the consequences of a catastrophic injection well failure on the performance of the WIPP repository was modeled by DOE under WIPP site conditions, but DOE used unrealistically conservative assumptions in many instances. Based on this, the Agency believed that catastrophic injection well failures that could affect the WIPP repository are unlikely, but even if such failures did occur, the volume of additional brine that would enter the repository would not be sufficient to affect repository performance. The Agency therefore concluded that fluid injection was appropriately screened out of performance assessment by DOE.

Both the Agency and DOE evaluated specific examples of fluid injection failure. In 1991, oil operator Doyle Hartman encountered a salt water blowout in the Bates # 2 development well in the Rhodes-Yates field 40 miles southeast of the WIPP site while drilling through the Salado Formation at a depth of 2,281 feet. In subsequent litigation, the court found that the source of the water flow was injection water from a long-term waterflood located more than a mile away. The brine encountered at the Hartman well was believed to have flowed through one or more anhydrite interbeds within the Salado evaporite from the waterflood operation. A similar event is reported to have occurred at Vacuum field, approximately 32 miles northeast of the WIPP site. This type of event is referred to as the "Hartman Scenario" in the CCA, and was examined by the Agency during our CCA review. The Agency concluded that based on their review of the WIPP, the Vacuum and Rhodes-Yates fields, the combination of the geologic differences, and the current well construction practices in the WIPP vicinity make it unlikely for there to be a repeat of the Hartman Scenario at WIPP.

2.2.1.2 CO_2 Injection as Addressed in the CCA Analysis

CO_2 flooding is generally considered a tertiary oil recovery method in that it is performed after both primary oil production and after waterflooding of a reservoir; it is conducted to further sweep additional oil to producing wellbores. DOE did not consider CO_2 injection in the CCA. Public comments on the CCA caused the Agency to examine this issue (Comments 8.T.1 though 8.T.6, Docket A-93-02, V-C-1, EPA, 1998c). The Agency discussed the potential effect of CO_2 injection and provided a simple but conservative analytical calculation to estimate the migration of CO_2 for a hypothetical tertiary recovery project in the Delaware Mountain Group near the WIPP Site (EPA, 1998c, pp 8-82 through 8-87). EPA concluded that CO_2 injection need not be considered as part of the CCA PA.

2.2.2 CRA Modifications

As part of its Delaware Basin Monitoring Program, DOE tracks the installation and activities related to waterflooding, fluid injection, and CO_2 injection in the Delaware Basin (CRA Appendix DATA, Attachment A, DOE, 2004). Results presented in the CRA indicate that since the CCA, 12 injection wells, 10 new salt water disposal wells, and two "injection" wells, have come on line. The salt water disposal wells inject into formations about 4000-5000 feet below ground surface, while the injection wells inject into formations about 1000-2000 feet deeper than the saltwater disposal wells zones (see CRA Appendix DATA, Attachment A, Table DATA-A-8). Of these, three salt water disposal wells occur within one mile of the WIPP Boundary (see CRA Appendix DATA, Attachment A, Figure DATA-A-1). DOE stated in CRA Appendix DATA Attachment A that "there are no secondary or tertiary recovery projects in the vicinity of the WIPP site utilizing carbon dioxide flooding as a means of oil recovery. The nearest operation of this type is located 40.23 km (25 mi) to the south in Loving County, Texas." DOE also state that there are no CO_2 pipelines to any of the fields in the New Mexico portion of the Delaware Basin, although secondary recovery (waterflooding) does occur there.

DOE addressed fluid injection in it's CRA FEP analysis (Appendix PA, Attachment SCR) for FEPs H27, Liquid Waste Disposal and H28, Enhanced Oil and Gas Production (DOE combined H-29, Hydrocarbon Storage, and FEPs H27 and H28 discussions, but this is addressed in Section 2.3). In this analysis, DOE states that the "hydrological effects of HCN fluid injection...through boreholes outside the controlled area have been eliminated from PA calculations on the basis of low consequence....Geochemical changes that occur inside the controlled area as a result of fluid flow associated with HCN fluid injection are accounted for in PA calculations. Liquid Waste Disposal, Enhance Oil and Gas Production, and Hydrocarbon Storage in the future have been eliminated...based on low consequence".

DOE revised the CRA to include arguments made by Stoelzel and Swift (1997) in a document prepared in response to EPA comments on the CCA. The Stoelzel and Swift analysis was not included in the CCA, and the CRA was updated to include this information. DOE concluded that 1997 Stoelzel and Swift modeling performed after submission of the CCA still confirmed assumptions presented in the CCA. That is, while the volume of water entering Marker Bed 139 is approximately 1500 m^3, this is still small enough to "not affect Stoelzel and O'Brien's (1996) conclusion [that fluid injection would not affect WIPP] even if somehow all [of the injectate] reached the WIPP." Flow was only modeled to occur in MB139 when injection pressures were used that were "conservatively higher" than currently in use near the WIPP, or 10 years of simultaneous tubing/casing leaks from a waterflood operation occurred; DOE concluded that neither of these situations were likely to occur. Also, leakage through a failed borehole could alter the fluid density in the affected unit, but DOE concluded that the density effect is of low consequence to the performance of the disposal system. With respect to changing the geochemical conditions in the thief zone by injection fluid, DOE stated that it is possible that fluid injection could alter the geochemical conditions in the thief zone if the leaks occur close to the edge of the WIPP controlled area, thereby impacting radionuclide injection rates via colloid transport and sorption changes. However, DOE stated that the majority of injection fluids would have compositions similar to fluids currently in the disposal system, addition of colloids from injection is unlikely.

With respect to waterflooding, DOE presents information in the CRA pertaining to the Vacuum Field and Rhodes-Yates Field, both of which have been waterflooded for 40 years and had confirmed leaking wells that resulted in brine entry into the Salado. DOE states that leakages from saltwater disposal wells or waterflood wells in the near future near WIPP are unlikely to occur because: 1) there are significant differences in the geology/lithology in the area where leakage occurred vs. that of the WIPP; 2) New Mexico regulations require emplacements of a salt isolation casing string that would reduce well leakage into the Salado and injection pressures are "not allowed" to exceed rock fracture pressure; and 3) recent improvements in well construction practices and reservoir operations reduce the occurrence of leakages from injection wells (e.g. injection pressures during water flooding kept below 23 x 10^3 pascals per meter to avoid fracture initiation; wells now completed using cemented and perforated casing rather than open hole completions). DOE concluded by citing a report by Hall et. al. (DOE, 2003a) which concludes that "injection well operations near WIPP have a very low failure rate, and that failures, although rare, are remedied quickly." DOE also concluded that injection well leakage in the near future are more likely to occur as a result of liquid waste injection, not waterflooding.

DOE makes no changes to the previous CCA argument that fluid injection may be screened from HCN based on low consequence. However, DOE argues that "the results of this [Stoelzel and Swift] modeling justify changing the screening decision for these FEPs from SO-R to SO-C for the future time frame. DOE states that enhanced oil and gas recovery through fluid and CO_2 injection occur in the Delaware basin, as does liquid waste disposal of byproducts from oil and gas production (CRA Appendix PA, Attachment SCR, Section SCR 5.2.1.6.3.1). However, DOE concludes that tertiary recovery using CO_2 miscible flooding have been "implemented with limited success in the Delaware Basin, but CO_2 miscible flooding is not an attractive recovery method for reservoirs near WIPP (DOE, 2003b). Even if carbon dioxide flooding were to occur, the effects (if any) would be very similar to those associated with waterflooding". DOE also states that fracturing of oil and gas bearing intervals, induced over a short period of time using high-pressure fluid injection, also takes place to enhance oil production. DOE states that with respect to hydraulic fracturing of oil reservoirs to enhance production "...this controlled fracturing is confined to the pay zone and is unlikely to affect the overlying strata."

In summary, as a result of these analyses pertinent to the historic, current and near future (HCN) time period, DOE concluded that because the activities currently have little consequence, it is appropriate to eliminate fluid injection from PA in future activities based on a screening of low consequence. DOE retained the CCA elimination of fluid injection from consideration in PA based on low consequence for the historic, current and near future time period (HCN). However, DOE changed the CCA Future screening argument for fluid injection from screened based on regulatory allowance (SO-R) to screened based on low consequence (SO-C).

2.2.3 EPA's Updated CRA Analysis

The Agency has examined the CRA (DOE 2004) and references (e.g., DOE 2003a, DOE 2003b, DOE 1997b) pertaining to fluid injection for enhanced recovery and brine disposal purposes, as well as CO_2 Injection related information, as presented in the CRA. The Agency also examined industry practice as a whole with respect to these activities, and used this information, coupled with CRA information, to update its analysis of the potential impacts of these activities on the integrity of the WIPP repository. The Agency's updated analysis is presented below.

2.2.3.1 Fluid Injection/Enhanced Recovery and Brine Disposal

The Agency has performed a re-analysis of well injection information to assess conclusions drawn by DOE that fluid injection, including CO_2 injection, need not be reconsidered in the CRA. To accomplish this, the Agency assessed ongoing fluid injection activities and regulatory controls. The Agency examined information presented in the CRA Appendix DATA, Attachment A, which includes the results of DOE's Delaware Basin Drilling Monitoring Program. In addition, the Agency examined supporting data assembled by DOE to generate Appendix DATA Attachment A, as well as readily available internet information and literature.

The Agency's re-analysis of oilfield injection activities and practices surrounding the WIPP site covered nine sections, including (1) the township where the WIPP site is located (T22S, R31E) and (2) the surrounding eight townships. In all, these townships cover an area of approximately 324 square miles, about 8 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.

It is important to recognize the distinction between a (1) brine or salt water disposal (SWD) well and (2) waterflood or enhanced recovery injection well. For a SWD well, water is typically injected into either (1) a non-commercial hydrocarbon-bearing reservoir or (2) a hydrocarbon-bearing reservoir, but the SWD well is sufficiently distant from oil and gas productive wells as to exhibit little or no effect on production. This contrasts with water injection wells that are designed to enhance hydrocarbon production rates and recovery through injection into the production zone, and includes both the processes of waterflooding and pressure maintenance. In these instances, water injection into a productive reservoir is performed to increase hydrocarbon production through a combination of fluid displacement and increasing reservoir pressure.

*Recent Water Injection Update***.** The Agency examined the CRA and additional supporting references to determine whether injection activities have increased in the WIPP vicinity. The 1997 *Injection Methods: Current Practices and Failure Rates in the Delaware Basin* report (DOE 1997) identified a total of 26 injection wells - 21 active SWD wells, three active water injection wells and two temporarily abandoned (TA) or inactive SWD wells within the study area. The 2003 update to this report, *Water Injection in WIPP Vicinity: Current Practices, Failure Rates and Future Operations* (DOE 2003a) has identified a total of 39 injection wells - 36 SWD or active water injection wells and three (3) wells TA or inactive. Excluding one well whose injection data are suspect, 12 new injection wells have been completed during the past 5 years (46% increase in well count). This information is consistent with that summarized in the CRA Appendix DATA, Attachment A. Average daily injection into all wells is now at approximately 44,000 BWPD or approximately 1,250 BWPD/well. This compares to the average daily injection of 32,500 BWPD at the end of 1997 or nearly 1,250 BWPD/well. Therefore, although total daily injection volumes have increased by 35%, the volume injected/well has stayed fairly constant at 1,250 BWPD/well.

New Mexico Oil Conservation Division Requirements- and Update. The Agency also evaluated whether regulations pertaining to fluid injection have changed since the CCA. 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 federal government. The regulations governing water injection are stated in rules **19.15.9.701** through **19.15.9.710**. 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 "[t]he 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." 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. This regulation was in place at the time the CCA was approved, and is still required.

To ensure the injection water is disposed only into the target interval, the NMOCD has established cementing requirements (see New Mexico Administrative Code (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." The NMOCD uses two types of tests to ensure wellbore integrity of water injection wells, the Bradenhead Test (BHT) and the Mechanical Integrity Test (MIT).

Typically, a BHT is conducted annually and a MIT is conducted at five-year intervals or any time the well is taken off-line for repairs. 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 15 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 (i.e., 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 at any time the tubing is pulled (removed) or the packer is reseated. In this test, the tubing-casing annulus is pressurized up to a minimum of 300 psi. A pressure recorder shows any loss of pressure over a 30-minute period. A sudden loss of pressure indicates annular fluids are leaking and constitutes a test failure. The well is then shut-in and the operator must take corrective action before returning the well to service. It should be noted that the MIT confirms the internal integrity of the casing but does not confirm that the well has external integrity - that is, that there is no flow behind the casing due to a bad cement job.

The NMOCD regulations pertaining to fluid injection and tests to ensure wellbore integrity were in place at the time of the CCA and have not been modified to diminish monitoring or well integrity requirements. EPA therefore concludes that the regulatory environment in place at the time the CCA was approved continues to be enforced today.

Types of Injection Well Failures. The Agency also assessed select information regarding types of injection well failures. The June 1997 DOE *Injection Methods in the Delaware Basin* report 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 of injection fluids out of zone. The BHT and MIT are designed to detect the first three types of failures; DOE believed and the Agency agreed, for the CCA, that the probability of tubing and packer leaks occurring simultaneously are very low and none of these three failures individually result in out of zone injection. Reviewed information indicates that this conclusion remains valid based on recent failure data for well failure types 1-3 because these failures are readily detected and repaired. That is, it continues to be likely that these failures, if they occurred, would not impact the WIPP site, as injected fluids would be contained within the downhole tubulars and would likely not migrate out of the desired injection interval.

For the fourth failure type, breakdown of cement sheath, the 1997 report recognized that "...the breakdown of the cement sheath between the casing and 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." The DOE's CCA report also noted that "...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." 1997 Stoelzel and Swift modeled the potential impact of such a failure as discussed in Section 2.2.2 EPA believes that these conclusions are reasonable.

The Agency believes that 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 do not exceed 0.8 psi per foot of depth, resulting in fracture pressures of approximately 4,000 and 6,400 psi at depths from 5,000 to 8,000 feet, which would be the typical injection depths in areas around the WIPP. The NMOCD requires the surface pressure not to exceed 0.2 psia per foot of depth to the top of the perforations. Since the hydrostatic pressure of a column of water is 0.435 psi/ft (for a salt saturated solution), the maximum sand face pressures would be 3,175 psi at 5,000 feet and 5,080 psi at 8,000 feet. The Agency concludes that regulatory requirements should sufficiently limit surface pressure to below the fracture pressure, thus precluding the development of vertical fractures.

We note that the sole exception to the NMOCD ban on injection above the 0.2 psi/ft of depth are for temporary tests, known as step-rate tests, to determine actual formation parting pressure (the pressure that induces a vertical fracture). 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 and should not result in vertical fracture creation/propagation.

Finally, the DOE's 1997 report addressed the geometry of a fracture created by injecting above the parting pressure. To summarize, because water, the injectant, has a relatively low viscosity (0.60 centipoises at 140 degrees 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 Agency continues to believe that 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.

Historical Injection Well Failures- Re-analysis. The Agency also examined whether new data concerning well failures would lead to reassessment of the failure scenarios. The DOE's 2003 Report, *Water Injection in WIPP Vicinity: Current Practices, Failure Rates and Future Operations* (DOE 2003a), identified 11 test failures for the 39 injection wells in the study area. However, five of the tests failed due to an inability to conduct the test. Excluding these five tests, six mechanical failures were observed since the 1997 CCA-related report. The most common cause of failure - observed three times - was a leaking packer. In each case, the packer was replaced and tested favorably. Casing leaks accounted for two failures, and the leaks were repaired and the wells returned to injection. For one well, the cause of the failure was not reported and no repair was made. This well remains shut-in at the present time. The low failure rate confirms that the NMOCD regulations governing the operation of SWD and injection wells appear to successfully control the injection failures and mechanical failures of the wells.

Hartman Scenario. The Agency also examined whether new reports of Hartman-type scenarios have occurred in the WIPP area. Review of DOE's 2003 report: *Water Injection in WIPP Vicinity: Current Practices, Failure Rates and Future Operations* (DOE 2003a) has shown no well failure cases similar to the Hartman Case in the vicinity of the WIPP area. Examination of drilling records summarized by DOE and readily available internet articles and other information did not indicate that any new Hartman-like scenarios have occurred in the WIPP vicinity since the CCA. Since the geologic setting at the WIPP has not changed with respect to those conditions affecting the Hartman Scenario, the Agency concurs that the continued probability of a Hartman type scenario occurring at the WIPP continues to be low, given the differences in geology and reservoir mechanics existing in the vicinity of the WIPP site.

2.2.3.2 CO_2 Injection

Unlike water and oil that do not mix, carbon dioxide has the ability, under common conditions, to interact with oil, reducing its surface adherence to the host rock, making the oil miscible, and changing its viscosity. The resulting effect is to free additional oil to be moved (swept) to producing wells. Although mobility of CO_2 within the reservoir is similar to water, the swept volume of rock for CO_2 versus water is much smaller. The particular properties of a reservoir are critical to the ultimate success of a CO_2 flood. The permeability of the rock to CO_2 and the potential for channeling of CO_2, thereby reducing the swept volume and reservoir pressure, are all very important factors, resulting in increased surveillance and monitoring costs. In addition, the economics of CO_2 flooding are controlled by the cost of the CO_2 and the capital cost of transportation of CO_2 to the required site (see Figure 3).

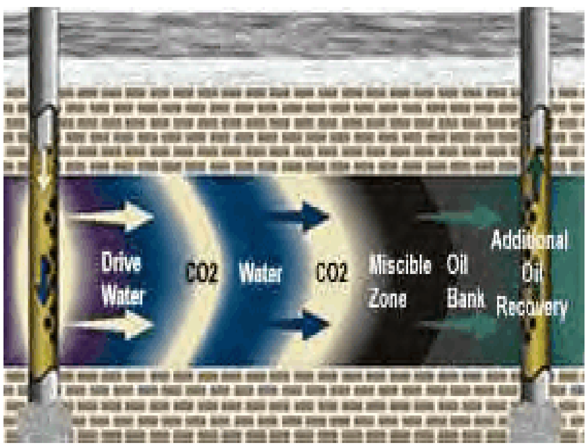

Figure 3. CO2 injection schematic, Courtesy of Occidental Petroleum: http//www.oogc.com

Since the approval of the CCA, DOE has prepared a second report entitled *An Updated Look at the Potential for Carbon Dioxide Flooding near the Waste Isolation Pilot Plant, Eddy and Lea Counties, New Mexico* (DOE 2003b). DOE concluded from this report that CO2 flooding had not occurred in the vicinity of WIPP and need not be reconsidered differently in the CRA. This report states that the Permian Basin has long been the world leader in CO2 flooding. In 1998, there were 77 active CO_2 floods worldwide, with roughly two-thirds (51) situated in the Permian Basin. In 2003, the numbers have changed very little - 78 worldwide and 51 in the Permian Basin. However, of the 51 Permian Basin CO_2 floods, only three are in sandstones, with the remaining floods dominated by the Central Basin Shelf dolomites, but with some Eastern Shelf limestones and Devonian tripolitic (siliceous) carbonates. All of the newly implemented Permian Basin area floods have been carbonate formation floods, but the Delaware Basin oil and gas reservoirs are within sandstone/clastic formations thus bringing to question whether CO_2 flooding would be used in the Delaware Basin and WIPP area. Therefore, the Agency agrees with the report conclusions that while CO_2 flooding occurs in the general area of the Delaware Basin, it is used in formations dissimilar to the oil/gas bearing units below WIPP. Reviewed data identify no new trend for implementing Delaware Basin CO_2 floods that has emerged since approval of the CCA.

The Agency also examined whether other reasons for CO_2 injection could impact the use of this mechanism in the area. For example, the possibility that CO_2 will become prevalent and inexpensive due to greenhouse gas emission issues was also considered by the Agency as a potential incentive for considering this activity. However, the technical and financial issues associated with developing a pipeline network and extending it to the area of the WIPP site, allowing delivery of CO_2 to the area fields, probably remains prohibitive. Many other, better, candidate fields are present along the Central Basin Platform in the San Andres reservoir system, and will likely continue to be where most CO_2 flooding takes place. The DBDSD also supports this conclusion, noting that there are currently no secondary or tertiary recovery projects in the vicinity of the WIPP Site using carbon dioxide as a means to recover oil. The nearest field where secondary recovery is ongoing (El Mar) is located in Loving County, Texas, 40.23 km (25 miles) from the WIPP Site. There are no CO_2 pipelines to any of the oil fields in the New Mexico portion of the Delaware Basin where secondary recovery in ongoing. Based on this information, the Agency concurs that it is highly unlikely that CO_2 flooding will occur for this reason near the WIPP site in the very near future.

The Agency also revisited public comments submitted on the CCA pertaining to CO_2 flooding. Several public comments on the CCA (Comments 8.T.1 though 8.T.6, Docket A-93-02, V-C-1) suggested that CO_2 is or could be used in the vicinity of WIPP and should be evaluated. The public believed this was necessary because they understood that: 1) CO_2 flooding has been demonstrated to be quite successful in mature fields in the Delaware Basin (EPA, 1998c), 2) the majority of the CO_2 flooding projects are situated in the Permian Basin, and 3) there was a possibility of adapting this enhanced oil recovery technology to the vicinity of the WIPP. As discussed above, the Agency believed and continues to believe that while used elsewhere, it is currently technologically impractical to use the method in the WIPP area of the Delaware Basin. To further the Agency's previous CCA analysis, the Agency performed a simple but conservative analytical calculation to estimate the migration of CO_2 for a hypothetical tertiary recovery project in the Delaware Mountain Group near the WIPP Site (EPA 1998c, pp 8-82 through 8-87). The Agency re-examined these calculations and continues to believe that the methodology, assumptions, and formulations used in the calculations still hold true for the CRA. These calculations showed that for long periods of time and using extremely conservative assumptions, most of the CO_2 would remain within a few hundred feet of the injection well and would not migrate to the WIPP repository.

In summary, the Agency's analysis continues to show that CO_2 injection does not pose a threat to the WIPP and should be omitted from the CRA PA calculations because of the minimal consequences that would occur as a result of CO_2 injection. Therefore, DOE's decision to screen CO_2 injection from the CRA PA continues to be appropriate.

2.2.3.3 DOE Response to Comments

The Agency submitted CRA completeness comment G-1 [Docket A-98-49: II-B3-72] to the DOE pertaining to fluid injection, which included a request that drilling-related parameters be updated and addressed. DOE responded by stating that three parameters (log permeability of non-degraded cement, log permeability of a partially degraded cement sheath, and log permeability of fully degraded cement sheath) were changed (see Table 1). DOE also stated that "a number of other parameters were changed for the CRA relating to features within and near the repository...[but] all these changes would only impact the dynamic conditions near the repository...[with respect to fluid injection]. DOE concluded by stating that the "collection of parameter changes...will not have any effects on the results of the cross-section model...Furthermore, the changes...result in slightly higher repository pressures when compared with the results of the CCA. Higher pressures in the repository decrease any hydraulic gradient between an injection borehole and the repository and would lead to less brine inflow than predicted...".

DOE was also asked to update the original CCA fluid injection evaluation using new well information and parameter estimates, such as injection volumes and flow rates of injection fluid. DOE provided summarized injection well failure information (presented in the CRA), changes in injection volumes, changes in injection pressures and changes affecting modeling assumptions including leak pathways. DOE concluded that "Injection volumes and the number of injection wells will continue to fluctuate to meet the need to accommodate produced water volumes; these fluctuations are to be expected. However, there is no current trend or evidence that would indicate a higher probability of failures or non-compliance with maximum permitted pressures. Occurrences of malfunctioning injection wells since the CCA remain very low, and do not present a credible pathway into the repository; there have been no occurrences of the compound failure of a leaking tubing/packer concomitant with a casing leak, which are both necessary to provide a leak pathway as modeled by Stoelzel and Swift (1997). Nonetheless, should such a low probability event occur, the analysis conducted by Stoelzel and Swift (1997) continues to bound any brine that might reach the repository under very conservative conditions and assumptions".

The Agency has examined the information provided by the DOE, and finds that it generally concurs with conclusions drawn in this TSD.

2.2.4 Conclusions

With respect to fluid injection activities, the Agency reviewed the CRA and supporting information, and determined that while fluid injection activity continues to occur in the WIPP vicinity, previous conclusions drawn with regard to fluid injection and the CCA do not require revision and fluid injection need not be considered differently in the CRA PA. The Agency reached the following conclusions:

- Ongoing development of oil- and gas-bearing reservoirs in the study area will continue throughout the next five years, provided economic returns remain favorable. The rate of drilling for the Delaware Mountain Group (Cherry Canyon, Brushy Canyon) oil wells is projected at 30 to 50 wells per year. Pennsylvanian gas well completions in the Atoka and Morrow formations should be similar to historic rates of 4 to 6 wells per year. New SWD wells will be needed to handle the additional volumes of produced water from new oil and gas wells.

- Strawn, Wolfcamp and Bone Spring reservoirs alone offer poor economic incentives for the use of enhanced oil recovery mechanisms. These reservoirs, however, are reasonable targets as existing wells in deeper Atoka and Morrow sands become depleted.

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

- For the study area, water injection into the Delaware Mountain Group formations is principally for water disposal, not enhanced oil recovery. Therefore, water injection volumes are virtually the same as produced water volumes. Several significant factors 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.

- NMOCD regulations governing the operation of injection wells appear to successfully control the injection pressures and mechanical failure of the injection wells. Mechanical failure rates are low. Migration of injected fluids out of zone is unlikely under these conditions.

- The issue of potential behind-pipe flow (due to cement sheath failure) was originally included in the 1997 DOE report and has been reiterated in the 2003 DOE report. Current NMOCD tests ensure that mechanical failure of tubing, packer, or casing is routinely detected and repaired. Furthermore, operators observe the statutory maximum injection pressures, thereby preventing vertical fracture growth and out-of-zone fracturing and breakout. However, no periodic testing to detect behind-pipe channeling (due to a bad cement job or cement sheath failure) using logs such as a radioactive tracer test (RTT) or a water flow log (WFL) are required at the present time. Therefore, a behind-pipe channel could remain undetected for a much longer period than a tubing, packer or casing failure. This is especially true for saltwater disposal wells, since operators have little economic incentive to monitor the path of injected fluids, unlike with a secondary waterflood or EOR project. Therefore, 1997 Stoelzel and Swift modeled the potential impact of this scenario and showed little impact on the WIPP repository.

In summary, with respect to fluid injection activities**,** the assumptions made in the CCA in relation to both water injection and the potential for CO_2 injection have not changed in the vicinity of the WIPP area of the Delaware Basin. Review of advances in well completions and secondary recovery/waterflooding mechanics and recoveries relating to well construction and production operations indicates that there have been no major changes in these areas since the last certification. Therefore, DOE's consideration of fluid injection need not be modified for the CRA.

With respect to CO_2 injection the following can be surmised:

- Based upon the Agency's review of current CO_2 injection activities in the Permian Basin, the WIPP area has several significant problems for future CO_2 flooding. All of the newly implemented Permian Basin area floods have been carbonate formation floods; no new trend for implementing Delaware Basin CO_2 floods has emerged since the CCA.

- The WIPP area has several attributes posing significant problems for future CO_2 flooding, including:

  - The lack of CO_2 pipeline infrastructure in the area,
  - The established nature of the channelized Delaware formation reservoirs,
  - The lack of a successful Delaware CO_2 flood analogue,
  - The lack of a successful waterflood demonstrating azimuthal sweep efficiency,
  - The lack of a CO_2 flooding company with holdings in the area, and
  - The lack of growth related to sandstone reservoirs in the CO_2 flooding industry.

- Currently there are no secondary or tertiary recovery projects in the vicinity of the WIPP Site utilizing carbon dioxide as a means to recover oil. The Agency analysis of a hypothetical CO_2 injection near the WIPP Site showed that for long periods of time and using extremely conservative assumptions, most of the CO_2 would remain within a few hundred feet of the injection well and would not migrate to the WIPP repository. Therefore, DOE's decision to screen CO_2 injection from the CRA PA calculations was appropriate.

2.3 Mineral Extraction Activities

2.3.1 CCA Results and EPA's CCA Conclusions

As part of the CCA, DOE performed analysis of these human-related events, and reached the following generalized conclusions regarding mining activities:

- The only natural resource currently being mined near the WIPP is potash within the McNutt member of the Salado Formation.

- Important effects of hydraulic conductivity change occur only within the Culebra.

- Spatially variant hydraulic conductivities were established in the Culebra by multiplying the hydraulic conductivity by a factor of one to 1,000 where they are affected by mining, consistent with EPA's suggested probability distributions (EPA, 1996, pp. 44-45). DOE assumed that this parameter distribution is uniform and was randomly sampled in LHS (Parameter Number 34).

- DOE assumed a mining probability of one chance in 100 in each century of the regulatory time frame, with a maximum of one occurrence during the 10,000-year time period.

DOE considered potash within the McNutt Potash horizon of the Salado formation when evaluating the effects of mining on the PA. Within the Carlsbad Known Potash Leasing Area, exploration holes have been drilled to evaluate the grade of the various ore zones. Although some of the ore zones have been labeled as high grade, the ore still may not be considered reserves if properties such as high clay content make processing uneconomical. None of the economically minable reserves identified by the NMBMMR (1995) lie directly above the waste panels. NMBMMR (1995) identified additional minable resources, including caliche, salt, and gypsum, but DOE concluded that these resources are not economically attractive, given the low sale price of the reserves and more cheaply mined alternatives. The Agency agreed with this conclusion.

Figure 4. Marietta Drum Miner at WIPP *Courtesy of DOE, http://www.wipp.ws.*

The Agency's review of minable reserves found that DOE reasonably identified current minable thicknesses and horizons near the WIPP. Figure 4 presents mining as performed at WIPP. DOE's estimate roughly corresponds to that identified in an EPA technical memorandum. The Agency recognized that this is not necessarily representative of the entire Delaware Basin, and it is conceivable that additional reserves could be mined in the WIPP area. However, speculation of this nature would extend to other horizons or reserves, which is beyond the intent of Section 194.32(b). The Agency therefore concurred with DOE's approach.

DOE stated that the only natural resource currently being mined near the WIPP is potash (potassium salts) within the McNutt member of the Salado Formation (CCA Chapter 6.4.6.2.3, p. 6-137). Consistent with Section 194.32(b), DOE therefore only considered potash mining in the performance assessment. Based upon information presented in NMBMMR (1995) and CCA Appendix MASS.15, DOE concluded that only Zones 4 and 10 of the McNutt member are currently economically minable (Zone 1 being at the base of the McNutt). The 4th ore zone is the zone nearest the proposed waste panel horizon at about 300 feet (100 meters) above the proposed waste panel horizon. DOE outlined the extent of the Zones 4 and 10 horizons within and outside of the WIPP boundary in the CCA and indicated that Zones 4 and 10 occur in a north-south trend along the eastern third of the controlled area. Outside of the controlled area, Zones 4 and 10 occur in an area to the immediate southeast of the WIPP Site Boundary. However, DOE indicated that potash resources occur and are expected to be mined within the Culebra groundwater modeling domain area, which extends to the south of the controlled area. DOE also noted that no minerals are present in minable quantities or types similar to those currently being mined in the Delaware Basin, in units above the Salado Formation (CCA Chapter 6.4.6.2.3, pp. 6-136 to 6-147).

As a result of public comments and the Agency's request for more information about the effects of solution mining, DOE provided supplemental information regarding potash solution mining in a May 14, 1997 response (Docket A-93-02, Item II-I-31). In this response, DOE concluded that the impacts of solution mining for potash should be the same as those for room and pillar mining, except for potential subsidence-induced hydraulic effects in the Culebra similar to those for typical mining practices. The Agency agreed that solution mining would not affect WIPP performance, since there is a large vertical distance between the WIPP horizon and the potentially mined horizon, and there is no hydraulic connection between the very low permeability Salado Formation at the WIPP horizon and the potash to be mined. Subsidence of overlying units due to the extraction of material would be the main problem with solution mining, but DOE screened out subsidence effects due to mining (Docket A-93-02, Item II-I-31). The Agency agreed with this conclusion because of the limited potential for interaction between the potash zone and the waste horizon.

During the public comment period, The Agency received questions that current minable resources will not be the same as what may be mined in the future. The Agency recognized that the mineral deposits that will be mined in the future may not be the same as those mined today; see EPA's Response to Comments Document, Section 8 (EPA, 1998c, Docket A-93-02, Item V-C-1). However, to avoid unnecessary speculation about what the size and shape of those mineral deposits might be, the Agency chose to accept the size and shape of existing mineral deposits as surrogates for the size and shape of the unknown mineral deposits that might be mined in the future. The Agency found that the impact of solution mining on the PA does not need to be analyzed for boreholes drilled in the future as specified in Section 194.33(d). Also, based on PA and supplemental information, the restricted scale of brine extraction, and the distance involved, the Agency concluded that while brine extraction occurs, its effects were appropriately screened out from consideration in the PA (because of low consequence).

2.3.2 CRA Modifications

DOE tracked mining-related activities as part of its Delaware Basin Monitoring Program. Both conventional and solution mining were covered in this analysis. CRA Appendix DATA, Attachment A indicates that potash leases essentially surround the WIPP site, with most occurring to the north and west of the WIPP facility. Of the 10 leaseholders identified in the CCA, five still retain leases in the WIPP area (Mississippi Potash appears to have purchased two of the leases, and IMC Kalium purchased one, while the other two were cancelled). The Delaware Basin Monitoring Program did not identify the occurrence of ongoing solution mining in the Delaware Basin in the vicinity of WIPP. However, solution mining for potash has been used outside the Delaware Basin in the Carlsbad Mining District, which "...comprises all of the potash mines in the area." Solution mining occurs in the McNutt interval. The DOE monitoring program identified a solution mining attempt initiated in the late 1960s on an AMAX lease about 22 miles north of the WIPP site. Solution mining created a cavern about 223 feet long and 10 feet high, but the subject potash ore zone was deemed too thin to make this method economically viable, and the mining attempt was halted.

DOE's Delaware Basin Monitoring Program also tracked a second potash solution mining endeavor initiated in May of 1997 by Mississippi Chemical, the principle potash leaseholder in the WIPP area. A Detailed Plan for solution mining was submitted to the BLM for further evaluation in May of 2002 for the pilot project, but the project is currently on hold due to lack of funding. DOE interviewed BLM, who indicated that while the Mississippi Chemical plan was proprietary, the pilot project was slated to occur about 19 miles north of the WIPP site. The pilot project was to involve pumping water down an existing shaft into a previously mined area, circulating waters around the mined pillars until saturation occurs, then extraction/surface evaporation of the recovered liquid.

DOE's Delaware Basin Monitoring Program also tracks solution mining of sulfur and other minerals, including "brine wells", which involve the injection of water in Class II injection wells into a salt formation, followed by extraction of the saturated salt water for use as an oil well drilling fluid. DOE identified no active sulfur solution mines in the Delaware Basin, with the closest solution mine, located west of Orla, Texas (which, too, used Class II injection wells for sulfur extraction), closed in June 1999. With respect to brine wells, DOE identified 15 brine wells in the Delaware Basin, 11 of which are active and four of which have been plugged and abandoned. Since the CCA, one new brine well has been permitted in the Delaware Basin (Quito West Unit #207). DOE indicated another well may have been drilled, but there were no records to confirm its installation.

Additionally, the DOE's Delaware Basin Monitoring Program tracks solution mining for the express purpose of creating a cavern for Naturally Occurring Radioactive Material (NORM) waste disposal. NORM waste is generated as a byproduct of oil/gas production. No such mining occurs in the Delaware Basin, but four solution mines were created for this purpose in Texas, with three of those solution mines in the greater Permian Basin.

DOE identified four FEPs that address mining and solution mining at or near the WIPP: H13, H14, H58 and H59. FEP H13, Conventional Potash Mining, is accounted for in performance assessment as required in 40 CFR 194.32 (b). No major changes to the potash reserve estimates were identified since the CCA, with the only change being the addition of a paragraph in CRA Chapter 2, section 2.3.1.1, indicating that potash reserves above the WIPP are non-economic (which the Agency concurred with), and that solution mining need not be considered in PA. DOE also states that "potash is the only known economically viable resource in the vicinity of WIPP that is recovered by underground mining." DOE discussed the solution mining process, indicating that langbeinite and sylvite are the two minerals of economic importance in the WIPP area, with only sylvite having the appropriate solubility to be considered for solution mining. Solution mining is typically used when deposits are at depths in excess of 3,000 ft to obtain the necessary rock temperatures that facilitate dissolution. Also, solution mining is used when the geologic setting is too complex for conventional mining, to recover potash pillars at the end of a mine's life, or when a mine is unintentionally flooded. The CRA (DOE 2004) points out that the Agency agreed with DOE's decision to screen solution mining from consideration in PA at the time of the CCA, and goes on to indicate that no information has been obtained to change conditions that supported this determination. DOE states "no new data or information has become available that comprise, reduce or invalidate the project's position on whether Solution Mining for Potash should be included in the PA calculations."

DOE's FEP analysis was updated to include brine well information, but DOE noted that the closest brine well is located about 30 miles north of the WIPP. DOE also indicated that subsidence related to brine well use is a possibility, and calculated that it would take 50 years of operation in the Carlsbad Brine Well and 15 years of operation at the Carlsbad Eugene Brine wells before the underlying cavity would reach a critical ratio with respect to collapse and subsidence of overlying beds (DOE 2004, CRA Appendix PA, Attachment SCR-5.2.2.4.8.1). DOE also addressed hydrogeologic effects of solution mining (DOE 2004, CRA Appendix PA, Attachment SCR-5.2.2.4.8.2), stating that solution mining could affect the hydraulic conductivity of overlying units via collapse of said units, or create local changes in pressure gradients due to extraction of fresh water or loss of injected fresh water or brine into overlying units. However, DOE concluded that because current solution mines are so distant from WIPP, none of these effects, including geochemical effects, could impact the WIPP.

The CRA indicates that solution mining for other minerals or for creating gas storage or NORM disposal still do not occur in the vicinity of WIPP (DOE 2004, CRA Appendix PA, Attachment SCR-5.2.2.4.6) . While a single New Mexico Delaware Basin facility uses a depleted gas reservoir for gas storage and containment, this was not a solution mined facility. Therefore, DOE concluded that elimination of solution mining from PA is still appropriate.

2.3.3 EPA's Updated CRA Analysis

Changes in mining activities and practices were evaluated, primarily through internet and telephone contact of government agency officials associated with mining in the WIPP area. For example, John Pfeil who is with the New Mexico Energy, Minerals and Natural Resources Department was queried about current mining practices, and offered the following:

- Since approval of the CCA, "nothing is happening" with respect to brine or sulfur mining advances; that is, no significant changes with respect to brine and sulfur mining have occurred since approval of the CCA.

- Since approval of the CCA, new uses of abandoned mines have not occurred, and this has been confirmed by Mr. Bob Abbotts in the New Mexico Abandoned Mine Land Bureau.

- With respect to potash, only two companies continue to mine the material in the WIPP area: Mississippi Potash and Kalium, Inc. However, Mississippi Potash laid off approximately 200 people in the last 12 months and their parent company recently declared bankruptcy, so continued operation could be questionable.

- While caliche and gypsum are mentioned in the CCA as potential minerals of interest, current research has shown that they continue to not be mined or explored in the Delaware Basin.

- Research has shown that actual mining for salt could be of interest; however, additional research only identified an operating solar salt plant near Carlsbad that harvests salt from a salt lake for the bulk animal feed business. The plant is operated by United Salt Corporation out of Texas (www.unitedsalt.com).

2.3.4 Conclusions

Based on the information summarized in the previous section, the mining assumptions in the CCA related to potash, sulfur, and brine have not changed. No other non-fuel minerals are currently being pursued in the area except for shallow salt mines.

2.4 Alternative Uses of Existing Mines

2.4.1 CCA Results and EPA's CCA Conclusions

The CCA did not directly consider specific alternative uses of mined excavations, except as part of its FEP analysis. For example, FEP H11, which included "hydrocarbon storage," focused on this aspect with respect to actual storage in boreholes, not storage of, for example, natural gas in mined areas around the WIPP. Also, DOE's CCA (DOE, 1995) assessed Tunneling, Construction of Underground Facilities, and Underground Nuclear Device Testing (H15, H16, and H20). DOE screened out these "excavation" FEPs, either primarily using the regulatory criteria in 40 CFR 194.25 (a), 194.32(a), and 194.33, or due to low consequences. That is, DOE screened out historical, current, or near-future mining for resources other than potash, since they have not significantly affected the WIPP site or the Delaware Basin in general, and are not likely to do so in the predictable future. The Agency concluded that exclusion of all "excavation" from long-term future PA consideration appeared to be appropriate, and in accordance with the criteria in 40 CFR 194. Potash mining is the exception, and is included in future PA scenarios and calculations.

2.4.2 CRA Modifications

Alternative uses of mined excavations were again considered under FEPs H11, H15, and H16 (DOE 2004). DOE clarified that hydrocarbon storage did not occur in existing mines in the WIPP area, stating "Hydrocarbon Storage takes place in the Delaware Basin, but it involved gas injection through existing boreholes into depleted reservoirs [not storage in mined caverns]." FEP H15 (Tunneling) and FEP H16 (Construction of Underground Facilities) were modified to recognize that on April 26, 2001, DOE formally requested approval of the installation of an OMNISita astrophysics experiment in the core storage alcove of the WIPP underground. DOE stated that the purpose of this project was to develop a "...prototype neutrino detector to test proof of concept principles and measure background cosmic radiation levels within the WIPP underground." The Agency approved the request on April 29, 2001. DOE concluded, however, that the projects did not require tunneling or excavation beyond the current footprint of the WIPP, so the screening argument for both H15 and H16 would remain unchanged with respect to the CCA (i.e., SO-R for both the historic, current, and near future time frames, as well as the Future time period).

2.4.3 EPA's Updated CRA Analysis

Since approval of the CCA, DOE and other agencies or organizations have proposed activities that use or generate mined areas near the WIPP. As stated in Section 2.4.2, DOE has proposed to allow universities and others to conduct other activities in the subsurface (including experimentation) as described in *Environmental Assessment for Conducting Astrophysics and Other Basic Science Experiments at the WIPP Site* (DOE 2000). DOE proposed to perform the experiments/activities in the former Experimental Area drifts excavated at the north end of the underground repository complex (Figure 5), although new excavations would also occur. Potential experiments proposed were:

- Los Alamos National Laboratory (LANL) WIMP Dark Matter HpSi Detector;
- Observatory for Multi-Flavor Neutrino Interactions from Supernovae (OMNIS);
- Enriched Xenon-136 Observatory (EXO);
- Germanium in Liquid Nitrogen Underground System (GENIUS);
- Institute for Nuclear and Particle Astrophysics and Cosmology's (INPAC) general purpose underground physics laboratory;
- The Majorana Project to measure double beta decay;

Figure 5. Experimental Gallery at the WIPP.
Courtesy of DOE, http://www.wipp.ws.

- A Neutrino Factory Detector; a study to assess Magnetic and Radiation Field Interaction; requiring additional excavation; Mine Tremor and Sensor Studies using explosive charges;
- Decoupling of Explosive Events in Salt to study the effects of small explosive charges in salt mines;
- Heat Study of Salt Deposits to assess thermal stress response of salt deposits;
- Nonproliferation and Nuclear Accountability Experiments;
- Deep Mine Electroplating for Crystal or Microprocessor Development; and,
- Creation of a UuNnO Facility that would involve a tank containing 450,000 metric tons (450,000 cubic meters) of ultrapure water, a room nearly 10 stories high, and an operating life of over 50 years.

The Agency evaluated DOE 2000 with respect to these activities. The Agency concluded that several principal changes in the WIPP design and operation activities approved by the Agency in the original certification decision would result from some potential experiments. These changes would involve an increase in the footprint of the excavated area of the WIPP facility, an increased demand for operational support services, the use of new equipment and materials in the WIPP underground, and the introduction of new operational and performance hazards. The total excavated area would increase if many of the experiments were conducted. The Agency also found that several new hazards related to accidents, dissolution, and mine stability would be apparent, and that the potential for catastrophic failure and performance assessment impacts needed to be better evaluated (or evaluated in the first place). The Agency concluded that although some experiments appear to have no significant impacts, such as the LANL WIMP experiment or the experiment related to OMNISita, many involve large volumes of potentially hazardous materials, such as pressurized gases and cryogenic liquids, that could affect repository air quality if released, large volumes of water that could affect repository stability by dissolving the halite, and large volumes of flammable liquids that could cause a major fire. Although many impacts would be short term and affect primarily the repository operational period, some, such as the catastrophic release of large water volumes and the increased area of subsidence, could affect long-term repository performance.

Since providing the Environmental Assessment report (DOE 2000), DOE has requested that certain of the experiments be allowed to move forward. Specifically, DOE requested that the Agency allow both the OMNISita and Majorana Projects to proceed. EPA reviewed information provided to the Agency about the Majorana Project and concluded "...we determine that the operation of Phase 1 and Phase 2 of the Majorana Project experiment does not constitute a significant departure from the 1996 Compliance Certification Application and supplemental materials." Similarly, the Agency reviewed OMNISita information provided by DOE, and concluded that, "...we determine that the operation of the OMNISita astrophysics experiment does not constitute a significant departure from the 1006 Compliance Certification Application and supplemental materials" (EPA, 2001 and 2002). The Agency approved the OMNISita project on August 29, 2001 and the Majorana Project on January 29, 2002. Both of these projects require no modification of the WIPP footprint and are passive in nature (DOE 2002b).

Also, recent articles have indicated that the entire Delaware Basin area (e.g., www.wipp.carslbad.us; www.radtexas.org, etc.) may be used, in the very near future, for other experiments and activities that could potentially involve the use of underground facilities. For example, DOE is attempting to acquire a plutonium "pit" facility at the WIPP site itself. Additionally, private concerns have expressed an interest in developing a uranium enrichment facility near the WIPP site, as well as developing RH-TRU waste disposal and characterization facilities in the Texas Delaware Basin. While these activities may not involve alternative uses of underground mines, investigation and awareness of these activities is warranted.

From a practical standpoint, research has shown that the most common use for salt caverns is to store hydrocarbons (e.g., propane, butane, ethane, ethylene, fuel oil, gasoline, natural gas, and crude oil). In 1975, the U.S. Congress created the Strategic Petroleum Reserve (SPR) program to provide the country with sufficient petroleum reserves to reduce any impacts from future interruptions in the oil supply. The SPR consists of 62 leached caverns in domal salt with a total capacity of 680 million bbl. The DOE is planning on adding an additional 250 million bbl of storage capacity.

A second use for salt caverns is to dispose of various wastes. Interest in using solution-mined salt caverns to dispose of oil field wastes has been growing. Presently, use of salt caverns for waste disposal in the United States has been limited. Salt caverns are utilized for waste disposal in Canada, the United Kingdom, Germany, the Netherlands, and Mexico. In the United States, the Railroad Commission of Texas has issued six permits for disposal of NOW (non-hazardous oilfield wastes) in salt caverns; four of these permitted sites are operational. At the present time, NORM (naturally occurring radioactive materials) wastes are not being disposed of in salt caverns anywhere in the world. However, review of federal regulations and regulations from the five states with interest in disposing NOW wastes in salt caverns - Texas, New Mexico, Oklahoma, Louisiana, and Mississippi - indicate that there are no outright prohibitions against NORM disposal in salt caverns or Class II wells.

2.4.4 Conclusions

Based on this research, unless the WIPP is to be used for experimentation or other purposes that would impact the footprint of the facility, additional consideration of these aspects as part of the CRA is not warranted at this time. However, tracking of site use and proposed uses of the area should take place. If such uses do occur, then additional assessment of the effects of underground experimentation should be performed. However, for the CRA, it does not appear that additional research into these areas for inclusion in PA is warranted at this time.

3.0 Summary

The following elements summarize conclusions and recommendations reached as part of this initial analysis of the specified human activities.

- The Agency's analysis of shallow and deep drilling activities within the Delaware Basin found that current drilling activities remain consistent with those assessed in the CCA. No updated analysis regarding shallow and deep drilling activities is necessary at this time, and no modification to PA assumptions appears warranted. DOE has identified and updated changes to the drilling rate, and has also updated its human-activity related parameters to be consistent with those used in the PAVT, where appropriate.

- With respect to fluid injection activities, the assumptions made in the CCA in relation to both water injection and the potential for CO_2 injection have not changed in the vicinity of the WIPP area of the Delaware Basin. Review of advances in well completions and secondary recovery/waterflooding mechanics and recoveries relating to well construction and production operations indicates that there have been no major changes in these areas since the last certification. Therefore, the Agency believes no re-analysis is required at this time based on available information, and the available information does not change the Agency's analysis and screening protocols in the last CCA relating to fluid injection activities and their potential impact on the integrity of the WIPP repository. DOE's decision to screen CO_2 injection from the PA calculations was appropriate. The Agency concurs that it is unlikely a CO_2 flood will take place in the vicinity of the WIPP area in the future.

- The mining assumptions in the CCA in relation to potash, sulfur, and brine have not changed. No other non-fuel minerals are currently being pursued in the area except for salt located in shallow salt mines.

- Unless DOE proposes to perform an alternative use of the mined area that impacts the WIPP footprint, such as using WIPP for expanded experimentation or other purposes, additional consideration of these aspects as part of the CRA is not warranted at this time.

However, tracking of site use and proposed uses of the area will continue.
EPA required DOE to change some CRA PA parameters and to rerun the CRA PA, the new PA is called the Performance Assessment Baseline Calculation or the PABC. DOE as part of the PABC implementation reevaluated the impact of EPA mandated changes on CRA FEPs. DOE determined that no changes were needed. EPA reviewed DOE reevaluation and agreed with DOE's conclusions (see EPA 2006, Docket A-98-49 Item II-B1-16, Section 2.0)

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ATTACHMENT A

Oil and Gas Productive Formations - An Update

Oil and gas in the WIPP vicinity of the Delaware Basin, are produced from several different formations, including the 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. 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. 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. Reservoirs are typically discontinuous, both laterally and areally.

The Delaware Mountain Group has been the target of three major periods of exploration and development effort. During the 1950s and 1960s, the uppermost portion of the interval, known as the Bell Canyon Formation, was a common, shallow target at depths of 5,000 feet or less in Loving, Ward, and Reeves Counties in West Texas and in southernmost Lea and Eddy Counties in New Mexico.

During the late 1970s and early 1980s, the upper and middle Cherry Canyon Formation was the focus of exploration within the Delaware Mountain Group. As with the Bell Canyon, production was primarily found in very fine to fine-grained sandstones, in which oil principally was trapped stratigraphically by lateral and vertical loss of porous sandstone into non-permeable sandstone, siltstone, or carbonate. Key Cherry Canyon fields discovered during this period included the Rhoda Walker and Dimmitt fields of west Texas and the Indian Draw and Esperanza fields of southeast New Mexico.

Prior to the mid-1980s, Brushy Canyon sandstones in particular were not an exploration target as; (1) they exhibited a low-resistivity log response and less permeability development than Bell Canyon reservoirs, (2) they lie at greater depths (generally > 7,000 feet), and (3) they yield unencouraging results on drill-stem tests (DST).

A third major phase of activity, focused on the deeper Brushy Canyon and lower Cherry Canyon formations, has taken place only within the last 15 years with drilling concentrated in the New Mexico portion of the Delaware Basin and in Ward and Winkler counties in Texas.

During the late 1970s and early 1980s, hundreds of wells were drilled in the Delaware Basin to deeper Pennsylvanian targets (mainly Morrow and Atoka), providing new insights into reexamining Permian formations, including the use of artificial fracturing to greatly improve production rates and per well drainage areas. As a result, more than 75 Mmbbl of oil and 175 bcf of gas had been produced by 1999 from the Brushy Canyon and Cherry Canyon reservoirs in

Eddy and Lea Counties of New Mexico.

The Bone Spring Formation of Leonardian age is comprised of three carbonate units that are separated by three clastic units. Facies changes are frequent, both due to depositional conditions and diagenetic changes. As with the Delaware Mountain Group formations, reservoirs are very discontinuous, so much so that different facies are often observed in adjacent wells.

The Morrow formation encompasses three different clastic intervals - Lower, Middle, and Upper. 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. 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 off-set.

The common trait of all these formations is reservoir discontinuity. Hence reservoirs may be characterized as relatively small, separated units, with production from several different reservoirs in a single field.

The 2003 report indicates that Delaware wells (752) constitute the vast majority of total producing wellbores, followed by Bone Spring (124) and Morrow (89). The Delaware and Bone Spring oil wells are typically drilled on a 40-acre spacing. A tight spacing is required due to poor recovery efficiency resulting from the reservoirs being of low permeability, laterally and areally discontinuous, and the produced fluids being relatively viscous. The Delaware per well estimated ultimate recovery (EUR) is 118,980 barrels of oil and 271,710 MCF of gas.

The Bone Spring estimated per well EUR is 30,900 bbls of oil and 132,430 MCF of gas.
In contrast, the deeper Atoka and Morrow, although also discontinuous, produce a lower viscosity fluid (gas) and are capable of draining a larger area. Average drainage areas are between 90 to 100 acres with some wells draining in excess of 400 acres. The Morrow per well EUR is 2.371 Bcf of gas and 15,000 bbls of oil.

Fluid injection is a convenient and widely-used oilfield practice for both enhanced oil recovery (EOR) (by waterflooding the oil reservoirs and maintaining the reservoir pressures above the bubble point), and also for produced brine disposal purposes. The oilfields in the WIPP area were relatively young in 1996 and many were still under primary production. Brine injection for disposal, pressure maintenance, and water flooding occur throughout the Delaware Basin and were under way in the vicinity of the WIPP site at the time that the CCA was approved. For example, in 1996 , there were more than 5,000 permitted injection wells in Lea County and 3,041 of these wells were active during the previous 12 months. The Class II injection wells are regulated under UIC permits issued by the New Mexico Oil Conservation Division (NMOCD). The average age of injection wells in the WIPP study area was approximately five (5) years in 1996. The relatively young average age of the injection wells in the study area was consistent with the increased rates of drilling and completion over the past 5 years. Water cuts in the vicinity of the WIPP area vary widely from 10% to 90%, with the majority in excess of 50%. Secondary recovery and disposal volumes can be expected to increase with time as the fields mature and the water cuts increase dramatically with declining oil production volumes. On-site disposal of oil and gas related liquid wastes via Class II wells was expected to remain the preferred disposal alternative as compared to trucking the fluids or pipelining over long distances to a centralized treatment or injection facility. The latter is much more expensive and in addition there may be risks associated with spills or pipeline ruptures producing potential environmental impacts.

Injection wells in the study area were typically cased hole with perforations opposite the Bell Canyon Formation, which is the uppermost member of the Delaware Mountain Group at depths ranging from 3,820 to 8,344 feet (1,164 to 2,543 m). The Bell Canyon Formation immediately underlies the Salado and Castile Formations in the salt section. Injection rates ranged from 5 to 3,500 barrels of water per day (BWPD) with most well rates in the range of 500 to 2,000 BWPD.