STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

APPLICATION OF OXY USA INC. FOR A CLOSED LOOP GAS CAPTURE INJECTION PILOT PROJECT, EDDY COUNTY, NEW MEXICO.

CASE NO. 22152
ORDER NO. R-22208

ORDER

The Director of the New Mexico Oil Conservation Division ("OCD"), having heard this matter through a Hearing Examiner on September 9th, 2021, and after considering the testimony, evidence, and recommendation of the OCD Engineering Bureau staff, issues the following Order.

FINDINGS OF FACT

1. Oxy USA, Inc. ("Applicant") submitted an application ("Application") to operate what OCD has classified as a closed loop gas capture ("CLGC") pilot project ("Project") which shall involve the intermittent injection of produced gas into selected production well(s) for the purpose of temporary storage and recovery during temporary interruptions of gas pipeline services ("CLGC event"). The practice is intended to prevent waste, reduce impacts associated with temporary interruptions of gas pipeline services, and to develop standard practices for similar projects.
2. At hearing, Applicant presented evidence through affidavits and expert witness testimony in support of the Application.
3. Applicant selected one or more producing oil and gas wells ("CLGC Well(s)") identified in Exhibit A in which to intermittently inject gas delivered by a common gas gathering system.
4. Applicant provided a statement regarding the CLGC well selection process and how the CLGC Well(s) will be sequenced and utilized in the Project.
5. Applicant proposed an area described in Exhibit A in which the Project shall be confined ("Project Area"). The Project Area is comprised of the lease(s) containing each CLGC Well and may include the adjacent lease(s) that are owned or operated by Applicant.
6. Applicant provided a general description and timeline of the Project.
7. Applicant provided a lease map which depicts the Project Area, lateral(s) of each CLGC Well, and the area which the gathering system incorporates including affected compressor stations.
8. Applicant proposed a maximum allowable surface pressure (MASP) of one thousand two hundred fifty pounds per square inch (1,250 psi) for each CLGC Well which will not endanger the mechanical integrity of the well or fracture the formation.

9. Applicant provided geologic and reservoir information to demonstrate that the injected fluids will enter only the pool(s) from which the CLGC Well(s) produce and will not affect correlative rights or migrate into other formations or protectable waters.
10. Applicant provided construction details for each CLGC Well and every well with a segment within one-half (½) mile of any segment of a CLGC Well.
11. The casing and cementing of each CLGC Well is or will be sufficient prior to injection to prevent leakage and prevent movement of formation or injected fluid from the injection zone into another zone or to the surface around the outside of a casing string in accordance with 19.15.26.9 NMAC.
12. Applicant conducted or intends to conduct a mechanical integrity test (MIT) upon each CLGC Well prior to injection which consisted of holding a pressure of at least one hundred ten percent (110%) of the proposed MASP or five hundred pounds per square inch (500 psi), whichever is greater, within the annulus of the production casing.
13. Applicant provided or intends to provide a cement bond log (CBL) which demonstrates the placement of cement and cement bond of the production casing and the tie-in of the production casing with the next prior casing for each CLGC Well.
14. Applicant provided a summary of its operational plan to ensure safe operation and efficient response in the event of an emergency, including a supervisory control and data acquisition (SCADA) system to monitor and collect relevant data.
15. Applicant proposed a method to allocate gas production during the period in which injected gas is being recovered.
16. Applicant provided an affirmative statement that it has examined the available geologic and engineering data and found no evidence of open faults or other hydrologic connections between the injection zone and any underground source of drinking water.
17. Applicant provided an affirmative statement that it has examined the available geologic and engineering data and determined that the total recoverable volume of hydrocarbons from the reservoir will not be adversely affected by the Project.
18. Applicant identified the source(s) of the gas to be injected during the Project, conducted an analysis of it, and either proposed a corrosion prevention plan to assure the integrity of the CLGC Well(s) ("Corrosion Prevention Plan") or certified that a Corrosion Prevention Plan is unnecessary to assure the integrity of the CLGC Well(s).
19. Applicant provided a copy of the Application by certified or registered mail to each owner of the land surface on which each CLGC Well is located and to each leasehold operator and other affected person(s), as defined in 19.15.2.7(A) NMAC, within any tract wholly or partially contained within one-half (½) mile of the well, in accordance with 19.15.26.8(B)(2) NMAC.

20. Applicant published public notice of the Application in a newspaper of general circulation in the county in which the CLGC Well(s) are located, in accordance with 19.15.26.8(C)(1) NMAC.
21. Applicant provided notice of the hearing in accordance with 19.15.4.9 NMAC.
22. Applicant is in compliance with 19.15.5.9(A) NMAC.
23. Applicant requested that approval be granted to subsequently add CLGC Well(s) to the Project via administrative approval.
24. Applicant requested that it be allowed to submit project status updates for this Project every twelve (12) months. The normal requirement for projects of this type is that project status updates be submitted every three (3) months.
25. Applicant requested that stipulations within surface commingling orders associated with the Project take precedence over the stipulations of an order issued for the Project. To ensure the protection of correlative rights, OCD has determined that the stipulations of all orders associated with the Project must be met.
26. Applicant requested that no additional well testing equipment be required to be installed for the Project.
27. Applicant requested an exception to the requirement that packers and retrievable bridge plugs be set within one hundred (100) feet of the uppermost perforations or casing shoe.

CONCLUSIONS OF LAW

28. OCD has jurisdiction to issue this Order pursuant to the Oil and Gas Act, NMSA 1978.
29. The New Mexico Administrative Code (NMAC) does not specify a process for the Application. Accordingly, approval of applications of this type are considered on a case-by-case basis after a public hearing.
30. Applicant's proposed method of allocation as modified herein ("CLGC Allocation Plan") shall, in reasonable probability, protect correlative rights.
31. Operation of the Project as required herein shall be in compliance with 19.15.26.10 NMAC.
32. The Project as stipulated herein shall, in reasonable probability, prevent waste and protect correlative rights, public health, and the environment.

ORDER

1. Applicant is authorized to operate a closed loop gas capture pilot project which shall involve the intermittent injection of gas into the production well(s) identified in Exhibit A for the purpose of temporary storage and recovery to prevent waste, reduce impacts associated with temporary interruptions of gas pipeline services, and to develop standard practices for similar projects.

2. Applicant is designated as the operator of the Project.
3. The Project Area shall comprise the lands described in Exhibit A.
4. The authority granted by this Order shall terminate two (2) years after the date of approval, provided however OCD, upon receipt of a written request submitted before the termination date and for good cause shown, may extend the authority granted by this Order. Required to be included with this request is a summary report.
5. Applicant's request that stipulations within surface commingling orders associated with the Project take precedence over the stipulations of this Order is denied. Applicant shall follow the conditions set forth in all surface commingling orders associated with the Project and this Order.
6. Applicant's request that no additional well testing equipment be required to be installed for the Project is denied. Applicant shall install and maintain any equipment necessary to meet the requirements of this Order.
7. Applicant's request that approval be granted to subsequently add CLGC Well(s) to the Project via administrative approval is denied.
8. The MASP for each CLGC Well shall be one thousand two hundred fifty pounds per square inch (1,250 psi). Applicant shall install equipment to limit the production casing pressure to less than or equal to the MASP and incorporate procedures into its operational plan to allow the safe reduction or cessation of injection to prevent the production casing pressure from exceeding the MASP.
9. Applicant shall allocate gas production during the period in which injected gas is being recovered as detailed in the CLGC Allocation Plan approved by OCD, provided however OCD, upon receipt of a written request from Applicant or upon its own determination that correlative rights may be harmed, may modify the CLGC Allocation Plan.
10. OCD has made the following modifications to the allocation method proposed by Applicant:
    a. If a CLGC Well has had less than twenty-four (24) hours of injection over a seven (7) day period, then Applicant shall dedicate a test separator to the CLGC Well for a period not less than forty-eight (48) hours following the CLGC event.
    b. If a CLGC Well has had more than twenty-four (24) hours of injection over a seven (7) day period, then Applicant shall dedicate a test separator to the CLGC Well for a period not less than seven (7) days following the CLGC event.
    c. If one hundred percent (100%) of the injected gas is recovered from a CLGC Well during the above specified time period, then Applicant is no longer required to dedicate a test separator to it.
    d. Following the above specified time period during which Applicant dedicates a test separator to a CLGC Well and if one hundred percent (100%) of the injected gas has not been recovered, then Applicant shall increase the frequency of well tests

conducted on the CLGC Well as much as is feasible until the injected gas is no longer being recovered.

11. Applicant shall conduct MITs pursuant to 19.15.26.11 NMAC on each CLGC Well in accordance with the following:

    a. A MIT shall consist of isolating the production casing from the reservoir by setting a retrievable bridge plug or packer not less than one hundred (100) feet below the top of the upper confining layer identified in Exhibit B, loading the production casing with an inert fluid, and conducting a pressure test with a pressure drop of not more than ten percent (10%) over a thirty (30) minute period.

    b. A chart recorder with a maximum two (2) hour clock and an appropriate maximum pound spring and which has been calibrated within the six (6) months prior to conducting the test shall be used during each MIT. Copies of the chart shall be submitted to OCD with a Form C-103 within thirty (30) days following the test date.

    c. No more than one (1) year prior to commencement of injection, a MIT shall be conducted to a pressure of at least one hundred ten percent (110%) of the MASP or five hundred pounds per square inch (500 psi), whichever is greater.

    d. No later than six (6) months after the Project has terminated, a MIT shall be conducted to a pressure of at least five hundred pounds per square inch (500 psi).

    e. Additional MITs shall be conducted as directed by OCD.

12. For any CLGC Well that the Applicant intends to inject via the tubing, Applicant shall submit a Form C-103 for review and approval by OCD with a detailed summary of their downhole configuration prior to commencement of injection.

13. Applicant shall install and maintain a SCADA system approved by OCD. The information collected during the active Project shall be maintained and made available to OCD upon request for no less than five (5) years after the cessation of the project, including:

    a. for each CLGC Well, the oil and gas production and injection flow rates, tubing pressure, and annulus pressure for all casing strings; and

    b. for each well required by OCD as described in Exhibit B, the oil and gas production and injection flow rates and production casing pressure.

14. No less than forty-eight (48) hours before initially placing each CLGC Well into service and available for injection, Applicant shall submit a notice of intent on Form C-103 and notify the OCD Engineering Bureau at ocd.engineer@state.nm.us. The notice of intent shall include the following:

    a. The results of the most recent MIT conducted upon the CLGC Well.

b. Confirmation that OCD has on record a CBL that demonstrates the placement of cement and cement bond of the production casing and the tie-in of the production casing with the next prior casing.

c. Confirmation that equipment is installed to limit the injection pressure to less than or equal to the MASP.

d. Confirmation that equipment to monitor the casing annulus pressure(s) and injection rate is installed.

15. For each CLGC Well, Applicant shall submit a Form C-115 in accordance with 19.15.7.24 NMAC and 19.15.26.13 NMAC or as otherwise directed by OCD.

16. Applicant shall monitor the production casing pressure and injection rate while injecting into a CLGC Well during each CLGC event. If any indication that a leak in the production casing occurs, then Applicant shall:

    a. immediately cease injection into the CLGC Well;

    b. within twenty-four (24) hours notify the OCD Engineering Bureau at ocd.engineer@state.nm.us;

    c. within thirty (30) days perform a MIT or other test approved by OCD demonstrating the well integrity of the CLGC Well and submit the results on Form C-103 to the OCD Engineering Bureau; and

    d. not recommence injection into the CLGC Well until OCD grants approval.

17. Applicant shall monitor the casing annulus pressure(s) while injecting into a CLGC Well during each CLGC event. For casings other than the production casing whenever:

    a. the pressure increases over normal operational conditions of more than one hundred pounds per square inch (100 psi) for the surface casing annulus and five hundred pounds per square inch (500 psi) for any intermediate annulus; in the event of such a pressure increase, Applicant shall notify the OCD Engineering Bureau at ocd.engineer@state.nm.us within twenty-four (24) hours;

    b. the pressure increases more than one thousand pounds per square inch (1,000 psi) over normal operational conditions; in the event of such a pressure increase, Applicant shall:

        i. immediately cease injection into the CLGC Well;

        ii. within thirty (30) days, submit a Form C-103 to the OCD Engineering Bureau containing a summary of the event that includes the cause for the pressure increase, description of any remedial actions and a revised operational plan to reduce and maintain the pressure below one thousand pounds per square inch (1,000 psi) over normal operation conditions; and

iii. not recommence injection into the CLGC Well until OCD has approved the revised operational plan.

18. For each CLGC Well, production shall occur via the tubing.

19. Applicant shall follow the approved Corrosion Prevention Plan if applicable. If the composition of the injectant being injected into a CLGC Well becomes inherently more corrosive than the composition approved by OCD, Applicant shall perform the following:

    a. immediately cease injection into the CLGC Well;

    b. within twenty-four (24) hours, notify the OCD Engineering Bureau at ocd.engineer@state.nm.us;

    c. within thirty (30) days, submit a Form C-103 to the OCD Engineering Bureau describing the alteration to the injectant's composition and a revised Corrosion Prevention Plan which addresses the effect of the alteration or a certification from a qualified person that no revision to the Corrosion Prevention Plan is required; and

    d. not recommence injection into the CLGC Well until OCD has approved the revised Corrosion Prevention Plan or certification that no revision to the Corrosion Prevention Plan is required.

20. If the casing of a CLGC Well fails or fluids leak from or around the CLGC Well or any well with a segment within one-half (½) mile of any segment of a CLGC Well, Applicant shall:

    a. immediately cease injection into every well with a segment within one-half (½) mile of any segment of the well from which fluids are leaking from or around;

    b. immediately notify the OCD Engineering Bureau Chief at the emergency contact number;

    c. within twenty-four (24) hours, notify the OCD Engineering Bureau at ocd.engineer@state.nm.us; and

    d. take all necessary steps and actions required and approved by OCD to correct the failure or leakage.

21. Applicant's request that it be allowed to submit project status updates for the Project every twelve (12) months is denied.

22. Applicant shall provide to the OCD Engineering Bureau at ocd.engineer@state.nm.us, project status updates every three (3) months after the approval of this Order and a summary report no later than three (3) months after the cessation of the Project or upon request from OCD. Status updates shall include a summary of actions taken that are related to the Project and a summary of any identified problems that includes solutions that are implemented to solve or mitigate them. Status updates may but are not required to include summaries of individual CLGC events that are not related to an identified problem. The summary report(s) shall include:

a. a summary of all project-related activity;

b. a review and supporting data regarding any identified problems and the solutions implemented to solve or mitigate them;

c. for each CLGC event, a summary of the results, including for each CLGC Well in which injection occurred ("involved CLGC Well"):

    i. average and maximum injection flow rates;

    ii. injection duration; and

    iii. total injected volume.

d. for each CLGC event, the following data graphed and tabulated with a resolution of at least: one (1) data point per hour beginning twenty-four (24) hours before the injection, four (4) data points per hour during the injection, and one (1) data point per hour ending twenty-four (24) hours after the injection:

    i. for each involved CLGC Well, the oil and gas production and injection flow rates and annulus pressure of all casing strings; and

    ii. for each offset well to each involved CLGC Well as described in Exhibit B, the oil and gas production and injection flow rates and production casing pressure.

e. for each CLGC event, a recovery profile for each involved CLGC Well and for each offset well to each involved CLGC Well as described in Exhibit B which experienced a change in production casing pressure or production during or immediately following the CLGC event. The volume of recovered gas shall be determined by taking the difference between the gas production following the injection and baseline production. The baseline production shall be determined by using production history to plot a production curve that estimates what the production would have been had injection not occurred. The recovery profile shall include:

    i. a summary of the results, including the volume and percent of total production recovered and the duration of time required to achieve that recovery; and

    ii. a tabulation of daily oil and gas production and baseline production totals; beginning a week before the CLGC event and ending when either the gas production is near equal to its baseline production or another CLGC event occurs for an involved CLGC Well.

23. Due to the nature of how Applicant allocates production to leases and pools related to the Project, the following modifications are made to the requirements of this Order provided that Applicant shall make every effort to meet the original requirements:

    a. Applicant is exempt from providing data points for oil and gas production from CLGC Wells for time prior to a CLGC event which it is unable to measure but shall provide its best estimate for production and an explanation for why the production was unable to be measured.

b. Applicant is exempt from providing data points for oil and gas production from offset wells it is unable to measure but shall provide its best estimate for production and an explanation for why the production was unable to be measured.

24. This Order does not grant an exception to 19.15.12.9 NMAC. Applicant shall not commingle oil or gas production from different pools or leases or transport oil or gas production from a lease until approval to do so has been granted by OCD in accordance with 19.15.12.10 NMAC or 19.15.23.9 NMAC, as applicable.

25. Notwithstanding the authority granted by this Order, Applicant shall be responsible for complying with all applicable OCD rules and any other state, federal, or local law or regulation and if the Project causes any harm or damage or threat of harm or damage to protectable fresh water, public health, or the environment.

26. If OCD determines that Applicant has failed to comply with any provision of this Order, OCD may take any action authorized by the Oil and Gas Act or OCD rules.

27. OCD retains jurisdiction of this case for the entry of such further orders as may be deemed necessary.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

ADRIENNE E. SANDOVAL
DIRECTOR

DATE: 8/07/2022

State of New Mexico
Energy, Minerals and Natural Resources Department

Exhibit A

Case Number: 22152
Order Number: R-22208
Operator: Oxy USA, Inc. (16696)

Project Pools

Pool Name	Pool Code
COTTON DRAW; BONE SPRING	13367

Project Area (NMPM)

UL or Q/Q	S-T-R
W/2 W/2, E/2	17-24S-31E
All	18-24S-31E

CLGC Wells

Well API	Well Name	UL or Q/Q	S-T-R	Pool
30-015-44459	Patton MDP1 17 Federal #1H	W/2 W/2	17-24S-31E	13367
30-015-44497	Patton MDP1 17 Federal #4H	W/2 E/2	17-24S-31E	13367
30-015-44444	Patton MDP1 17 Federal #5H	E/2 E/2	17-24S-31E	13367
30-015-45079	Patton MDP1 17 Federal #176H	E/2 E/2	17-24S-31E	13367
30-015-44317	Patton MDP1 18 Federal #1H	W/2 W/2	18-24S-31E	13367
30-015-44337	Patton MDP1 18 Federal #2H	E/2 W/2	18-24S-31E	13367
30-015-44333	Patton MDP1 18 Federal #3H	E/2 W/2	18-24S-31E	13367
30-015-44272	Patton MDP1 18 Federal #5H	E/2 E/2	18-24S-31E	13367
30-015-44273	Patton MDP1 18 Federal #7H	E/2 E/2	18-24S-31E	13367
30-015-44316	Patton MDP1 18 Federal #23H	W/2 E/2	18-24S-31E	13367
30-015-44338	Patton MDP1 18 Federal #33H	W/2 E/2	18-24S-31E	13367

State of New Mexico
Energy, Minerals and Natural Resources Department

Exhibit B

Case Number: 22152
Order Number: R-22208
Operator: Oxy USA, Inc. (16696)

CLGC Wells and Offset Wells

Well API	Well Name	MASP: 1,250 psi
30-015-44459	Patton MDP1 17 Federal #1H	

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-41343	Patton 18 Federal #8H
30-015-44460	Patton MDP1 17 Federal #2H
30-015-44272	Patton MDP1 18 Federal #5H
30-015-44273	Patton MDP1 18 Federal #7H

Well API	Well Name	MASP: 1,250 psi
30-015-44497	Patton MDP1 17 Federal #4H	

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-44496	Patton MDP1 17 Federal #3H
30-015-44445	Patton MDP1 17 Federal #6H
30-015-44444	Patton MDP1 17 Federal #5H

Well API	Well Name	MASP: 1,250 psi
30-015-44444	Patton MDP1 17 Federal #5H	

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-44496	Patton MDP1 17 Federal #3H
30-015-44445	Patton MDP1 17 Federal #6H
30-015-44497	Patton MDP1 17 Federal #4H

Well API	Well Name	MASP: 1,250 psi
30-015-45079	Patton MDP1 17 Federal #176H	

Upper Confining Layer: Low permeaility and porosity limes and siltstones at the top of the Avalon (~8,100 to 8,550 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
	NONE

Well API	Well Name	MASP:	1,250 psi
30-015-44317	Patton MDP1 18 Federal #1H		

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-44525	Nimitz MDP1 13 Federal Com #3H
30-015-41343	Patton 18 Federal #8H
30-015-44337	Patton MDP1 18 Federal #2H
30-015-44333	Patton MDP1 18 Federal #3H
30-015-44316	Patton MDP1 18 Federal #23H

Well API	Well Name	MASP:	1,250 psi
30-015-44337	Patton MDP1 18 Federal #2H		

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-44525	Nimitz MDP1 13 Federal Com #3H
30-015-41343	Patton 18 Federal #8H
30-015-44317	Patton MDP1 18 Federal #1H
30-015-44333	Patton MDP1 18 Federal #3H
30-015-44316	Patton MDP1 18 Federal #23H

Well API	Well Name	MASP:	1,250 psi
30-015-44333	Patton MDP1 18 Federal #3H		

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-44525	Nimitz MDP1 13 Federal Com #3H
30-015-41343	Patton 18 Federal #8H
30-015-44317	Patton MDP1 18 Federal #1H
30-015-44337	Patton MDP1 18 Federal #2H
30-015-44316	Patton MDP1 18 Federal #23H

Well API	Well Name	MASP:	1,250 psi
30-015-44272	Patton MDP1 18 Federal #5H		

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-41343	Patton 18 Federal #8H
30-015-44460	Patton MDP1 17 Federal #2H
30-015-44273	Patton MDP1 18 Federal #7H
30-015-44459	Patton MDP1 17 Federal #1H

Well API	Well Name	MASP:	1,250 psi
30-015-44273	Patton MDP1 18 Federal #7H		

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-41343	Patton 18 Federal #8H
30-015-44460	Patton MDP1 17 Federal #2H
30-015-44272	Patton MDP1 18 Federal #5H
30-015-44459	Patton MDP1 17 Federal #1H

Well API	Well Name	MASP:	1,250 psi
30-015-44316	Patton MDP1 18 Federal #23H		

Upper Confining Layer: 2nd Bone Spring Lime overlaying 2nd Bone Spring Sand (~9,600 to 9,850 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
30-015-44525	Nimitz MDP1 13 Federal Com #3H
30-015-41343	Patton 18 Federal #8H
30-015-44317	Patton MDP1 18 Federal #1H
30-015-44337	Patton MDP1 18 Federal #2H
30-015-44333	Patton MDP1 18 Federal #3H

Well API	Well Name	MASP:	1,250 psi
30-015-44338	Patton MDP1 18 Federal #33H		

Upper Confining Layer: Low permeaility and porosity limes and siltstones at the top of the Avalon (~8,100 to 8,550 TVD at Patton MDP1 18 Federal #6H)

Offset Well API	Offset Well Name
	NONE