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

APPLICATION OF DCP MIDSTREAM, LP TO RE-OPEN CASE NO. 13589 TO AMEND ORDER NO. R-12546 FOR THE LIMITED PURPOSE OF AUTHORIZING A SECOND ACID GAS INJECTION WELL, LEA COUNTY, NEW MEXICO.

CASE NO. 13589
ORDER NO. R-12546-K

<u>ORDER GRANTING DCP MIDSTREAM, LP'S MOTION TO AMEND ORDER NO. R-12546</u>

THIS MATTER came before the Oil Conservation Commission ("Commission") on the motion of DCP Midstream, LP, previously known as Duke Energy Field Services, LP, to amend Order No. R-12546, issued on May 5, 2006, to authorize a second acid gas injection well. The Commission, having reviewed and considered the motion and the testimony and evidence presented at the Commission's Special Hearing on December 20-21, 2012,

<u>FINDS THAT</u>:

1. Notice has been given of the application and the hearing of this matter, and the Commission has jurisdiction of the parties and the subject matter herein.

2. On May 5, 2006, the Commission entered Order No. R-12546, which granted Duke Energy Field Services, LP's application to inject acid gas into the Lower Bone Spring (Wolfcamp) formation through a well to be drilled 1980 feet from the South and West lines (Unit K) of Section 30, Township 18 South, Range 37 East, NMPM, Lea County, New Mexico, subject to Duke Energy Field Services, LP, now DCP Midstream, LP ("Applicant" or "DCP"), meeting certain conditions prior to commencing injection.

3. Paragraph N of Order No. R-12546 provided that prior to commencing injection into the Linam Ranch AGI No. 1 well ("AGI No. 1"), DCP had to secure Oil Conservation Division ("Division") approval of an appropriate modification of the discharge permit for the Linam Ranch Gas Plant ("Plant").

4. Paragraph Q provided that prior to commencing injection, DCP had to submit to the Division's Engineering Bureau written evidence of satisfaction of the conditions precedent to injection as provided in Order No. R-12546.

5. Order No. R-12546 has been amended several times to allow DCP additional time to drill and complete the AGI No. 1 well, Order No. R-12546-B and Order No. R-12546-C, and to authorize DCP to temporarily inject acid gas into its AGI No. 1 well and stay Order Paragraphs N and Q. Order Nos. R-12546-D, E, F and G.

6. In Order No. R-12546-I, the Commission ordered that a) DCP is no longer required to obtain a modification of its discharge for the Linam Gas Plant and Paragraph N of Order No. R-12546 no longer applies; b) that DCP is not required to obtain an administrative order from the Division as previously ordered in Paragraph Q of Order No. R-12546; c) that Paragraph O of Order No. R-12546 be amended to remove the requirement that an audible alarm be placed at Randy Smith's home, and to substitute the requirement that DCP provide an audible alarm at the residence or business of any person located within the radius of exposure if the person requests that DCP install an audible alarm; and d) that Paragraph F of Order No. R-12546 be amended to require that DCP pressure test the casing in the AGI No. 1 well from the surface to the packer-setting depth every two years instead of every five years.

7. On October 31, 2012, DCP filed an administrative application (OCD Form C-108 and attachments), seeking authority to inject acid gas (carbon dioxide and hydrogen sulfide) into the Lower Bone Spring (Wolfcamp) formation through a second acid gas injection well, Linam Ranch AGI No. 2 well, at a depth interval of 8,710 feet to 9,085 feet below the surface, and at a location 2120 feet from the South line and 2120 feet from the West line (Unit K) of Section 30, Township 18 South, Range 37 East, NMPM, in Lea County, New Mexico ("AGI No. 2"). The purpose of the second well is to serve as a second or redundant well to the previously approved AGI No. 1 well and to dispose of natural gas processing wastes from Applicant's Plant, located in Northeast Quarter of Section 6, Township 19 South, Range 37 East, in Lea County.

8. At the direction of the Director of the Division, pursuant to Rule 19.15.4.20.B NMAC, this case was set for hearing before the Commission.

9. At the hearing, Randy and Naomi Smith and the Smith Farm and Ranch, a surface owner and resident in the vicinity of the proposed injection site, appeared as Protestants, and offered evidence in opposition to the permit sought by Applicant. The Division appeared as an intervenor, and offered evidence in support of the application and relevant to conditions it urged the Commission to place upon the permit if granted.

<u>Applicant's Evidence</u>

10. The Applicant produced three witnesses: Alberto A. Gutiérrez, a registered geologist and president of Geolex, Inc., who is a consultant to Applicant and an expert in acid gas well operation and design, petroleum geology, and groundwater contamination; Roberto Torrico, a project manager employed by the Applicant for the Plant and a petroleum engineer; and Steve Boatenhamer, who is employed by the Applicant as manager of the Plant.

11. Mr. Gutiérrez testified that notice of the application and hearing was mailed to all "affected persons," including surface landowners, within a one-mile radius of the proposed injection, and published notice in the Hobbs News-Sun newspaper identifying all unlocatable interests. (DCP Exh. 2).

12. Mr. Gutiérrez testified that the proposed AGI No. 2 well would provide redundant injection capability that would allow the Plant to continue injecting during planned and unplanned plant shut downs or for maintenance of one of the injection wells. He testified that such redundancy would increase the facility's reliability, reduce flaring events at the Plant, and decrease the likelihood that upstream wells would have to be shut in. He stated that the benefit of a second well would be increased protection of human health and the environment and protection against waste and damage to the producing reservoirs

13. Mr. Gutiérrez testified that the need for a second injection well became apparent after the AGI No. 1 well had to be shut in for a period of approximately three weeks for a workover in April and May of 2012. In December 2011, DCP determined there was a leak somewhere in the AGI No. 1 well when DCP was unable to conduct a required mechanical integrity test. DCP entered into an Administrative Compliance Order with the Division to conduct a workover. During the workover, DCP discovered that tubing bad become corroded in the lower 60 feet above the packer. DCP attempted to insert a new packer but failed. DCP inserted new tubing into the existing packer. DCP agreed to provide OCD with monthly reports and conduct a mechanical integrity test every six months. The AGI No.1 well passed the mechanical integrity test in November 2012.

14. As a result of that workover, Mr. Gutierrez stated that DCP identified enhancements that it could apply to the design and operation of the first well and a second proposed well, such as the addition of anti-corrosive tubing, biocide and anti-corrosive additives to the diesel within the annular space, down-hole monitoring equipment, and improved temperature controls to reduce the temperature fluctuation of the injected acid gas. He stated that additional work is required in the AGI No. 1 well to place a stacked packer in the well's tubing to isolate some compromised casing.

15. Until the stacked packer can be installed, Mr. Gutiérrez stated that the AGI No. 1 well is operating under an approved C-103, which requires monthly analysis and reporting of technical parameters to the Division and a mechanical integrity test every six months. Mr. Gutiérrez testified that the AGI No. 1 well is safe for operations, as demonstrated by the fact that it passed the mechanical integrity tests conducted in May and November of 2012.

16. Mr. Gutiérrez testified that the preferred location for the proposed AGI No. 2 well is a different location than the original location identified in the filed C-108 application. The preferred location for the AGI No. 2 is 1600 feet from the South line and 1750 feet from the West line (Unit K) of Section 30, Township 18 South, Range 37 East, NMPM. He stated that the change in the proposed location for the well did not alter

his technical analysis of the proposed injection, nor did it affect the required notice of the application and hearing.

17. Mr. Gutiérrez testified that a second well would operate under the existing limitations imposed by Order No. R-12546, as amended, and that DCP does not seek any increase to the authorized injection pressure under that order, which is 2,644 pounds per square inch at a specific gravity of the treated acid gas stream of 0.8. He stated that DCP is currently injecting at a pressure of less than 1,500 pounds per square inch on average, which is more than 1,100 pounds per square inch below the maximum allowable operating pressure.

18. Mr. Gutiérrez testified that his analysis of the operation and injection through the AGI No. 1 well confirms his original analysis that the proposed target injection zone in the Lower Bone Spring formation is a closed system and is an ideal reservoir for acid gas injection. He stated that the injection zone is below any productive oil and gas formations, has an excellent caprock and geologic seal that isolates the injected acid gas from any freshwater sources, containing it within the injection formation, and is laterally extensive, underpressured, and highly permeable. He testified that the radius of injection over a 30-year timeframe is expected to extend about 0.47 miles from the point of injection.

19. Mr. Gutiérrez further testified that fresh water wells in the vicinity produce water from the Ogalalla or shallower aquifers, and that the deepest freshwater well is approximately 270 feet deep. He explained that the injection zone is approximately 8,300 feet below the base of any freshwater. He testified that freshwater wells in the area exhibit high levels of sulfate, from 60 to 30 parts per million in the Ogallala to 100 to 6,800 parts per million in the Dockum Group throughout Lea County, New Mexico.

20. The AGI No. 2 well will have surface casing to a depth of approximately 500 feet, and there will be a total of four casing strings, each with cement circulated to the surface. The casing strings include intermediate casing that will run from the surface to just above the injection zone and also will be cemented back to the surface. Injection will be accomplished through sealed tubing, and the casing-tubing annulus will be filled with diesel treated with biocide and anti-corrosion inhibitors. Mr. Gutiérrez stated that his analysis of all wells that penetrate the injection zone within the area of review indicates that they are adequately cemented and protective of hydrocarbon and freshwater zones.

21. Mr. Gutiérrez testified that DCP will need to modify its Division-approved Rule 19.15.11 NMAC hydrogen contingency plan to address the addition of a second injection well.

22. On cross-examination, Mr. Gutiérrez testified that it is possible and reasonable for the Division and DCP to agree on parameters for immediate notification of the Division in the event anomalous data are encountered that could indicate the need to

conduct a mechanical integrity test. He stated that the Division's proposed requirement to conduct an annual mechanical integrity test, instead of once every two years, is reasonable and prudent, and that once a new packer is placed in the AGI No. 1 well that it also should be subject to an annual mechanical integrity test, rather than once every six months, as required now. But, he stated that the Division's proposed requirement to provide monthly reporting is unnecessary for the proposed AGI No. 2 well, because the injection data would be available for review by the Division any time if the notification parameters are triggered. He further testified that the AGI No. 1 well can be retrofitted to include some of the enhanced designs of the AGI No. 2 well, such as additional corrosion resistant tubing, down-hole monitoring equipment, and diesel with biocides and corrosion inhibitors.

23. Mr. Torrico testified that DCP learned from operation of the AGI No. 1 well that the injection parameters must be monitored frequently and that some operational controls could be improved, in particular those governing the temperature of the injected acid gas stream.

24. Mr. Torrico testified that, based on its experience operating the AGI No. 1, DCP decided to include enhanced materials in the design of the proposed AGI No. 2 well and to institute the improved operational controls, including the down-hole sensors, that would improve the performance of the existing AGI No. 1 well and the proposed AGI No. 2 well. Together these design and operational enhancements will improve the overall operations, reliability, and integrity of DCP's Plant facility and would reduce the potential for flaring events at the Plant.

25. Mr. Torrico testified that having a second injection well would provide DCP redundancy in its operations that would improve the Plant's reliability and would provide DCP flexibility to operate one or both injection wells alternately or simultaneously without exceeding the maximum injection pressure. If two injection wells are operated simultaneously, DCP would not be able to increase the throughput of acid gas through the plant because injection is currently limited by the plant's two compressors. He stated that DCP is not expecting daily injection rates to exceed 7 million cubic feet per day, as contemplated by the analysis supporting Order No. R-12546.

26. Mr. Boatenhamer testified that a second injection well would reduce the likelihood that thousands of wells upstream of the Plant would have to be shut in should there be maintenance or operational issues associated with one of the injection wells. He stated that when upstream wells are shut in, producing wells upstream of the Plant might be forced to vent or flare across Lea and Eddy Counties, and that such shut-ins could result in damage to the producing reservoirs.

27. Mr. Boatenhamer testified that the preferred location of 1600 feet from the South line and 1750 feet from the West line (Unit K) of Section 30, Township 18 South, Range 37 East, NMPM, is optimal for at least four reasons. First, the preferred location would locate both injection wells so that neither would be downwind of the other based

on the prevailing winds in the area. This would increase the safety of workers onsite working in the area of either injection well while the other injection well is operational. Second, the preferred location puts the AGI No. 2 farther from the boundary of the facility fence line. Third, the preferred location also is farther from the Smiths' property. Fourth, the preferred location would allow the second well to integrate with and tie in to the Plant's existing facilities with less pipe and fewer tie-ins.

28. Based on Mr. Gutiérrez's recommendations, Mr. Boatenhamer testified that DCP undertook a review of the operations and design of the temperature controls that govern the temperature of the injected acid gas stream. He testified that DCP moved the location of the controller to a more controlled location and installed a thermocouple, programmable logic controller, and a distributive control system to allow DCP to implement tighter controls over the injection temperature parameters and to include an alarm system that provides notifications when temperatures fluctuate beyond set parameters.

29. Mr. Boatenhamer testified that as a result of these design and operational improvements DCP has maintained a more consistent acid gas stream temperature, with fluctuations from approximately 110° F to 125° F, where temperature fluctuations before the modifications were as much as 80° F.

30. Mr. Boatenhamer testified that the Division's third proposed condition requiring monthly reporting for the AGI No. 2 well is not necessary because annual mechanical integrity tests will conclusively establish the integrity of the well.

31. Mr. Boatenhamer testified that there has never been a release from the acid gas injection well operated by DCP to the air that triggered the perimeter monitors that triggered DCP's Rule 11 contingency plan.

<u>Division's Evidence</u>

32. The Division, as an intervenor, presented two witnesses: William V. Jones, a petroleum engineer whose duties include reviewing applications for injection permits, and Elidio Gonzales, supervisor of the Division's Hobbs District Office.

33. Mr. Jones testified that DCP's application is approvable and he recommended that the Commission approve the application: the application is complete; it demonstrates that the proposed second acid gas injection well will prevent waste and protect correlative rights; it demonstrates that the injectate will stay within the injection zone and will protect freshwater; DCP has all the necessary financial assurances in place; notice was proper; there is no hydrocarbon production in the injection zone; and all the wells that penetrate the injection zone are properly completed and plugged to isolate and contain the injection. He further testified that the injection zone is underpressured, and has enough porosity and permeability to receive the proposed injections for a long time.

34. On cross-examination, Mr. Jones testified that the U.S. Environmental Protection Agency rules require the Division to review well plugging records for wells in the area of review of a proposed injection well. He stated that wells plugged and abandoned in the 1980s and later accurately depict the plugging and that he was satisfied that the well records for the wells within the area of review for the AGI No. 2 well show that none of the wells present a concern.

35. Mr. Gonzales testified that a second acid gas injection well will prevent waste and environmental harm by reducing the possibility that upstream wells would have to flare or vent if the existing injection well has to be shut in, potentially watering out the production well and damaging the wellbore. He testified that a second injection well would result in enhanced safety for the public and the environment. He further testified that the four strings of casing in AGI No. 2, incorporating a corrosion resistant alloy, will be protective of freshwater sources.

36. Mr. Gonzales further testified that DCP maintained communication with himself and the Division when DCP was preparing to conduct a mechanical integrity test on the AGI No. 1 in 2012 and during the events that followed, and that DCP contacted the Division immediately when there was an indication of a potential problem. On cross-examination, Mr. Gonzales testified that DCP operates the Plant as a diligent and prudent operator and that he has no concerns about the operation or safety of the AGI No. 1 well.

37. Mr. Gonzales testified that an annual mechanical integrity test for acid gas injection wells is a good monitoring tool to ensure the integrity of injection wells and to verify the integrity of injection wells whenever anomalous data are recorded indicating a potential problem. He also testified in favor of daily monitoring by DCP and monthly reporting to the Division of certain parameters as recommended by the Division.

38. Mr. Gonzales testified that the District and DCP can coordinate to establish immediate notification parameters prior to injection through the AGI No. 2 well that would include injection temperatures and the differential between the tubing and annulus pressures. However, Mr. Gonzales testified that it is not possible to finalize the notification parameters until the well begins injecting.

39. On cross-examination, Mr. Gonzales testified that he would recommend retrofitting, to the extent reasonable, the AGI No. 1 well with some of the enhanced designs proposed for the AGI No. 2 well, such as down-hole monitoring, corrosion resistant tubing, and the addition of biocide and corrosion inhibitors to the diesel in the annulus.

<u>Protestants' Evidence and Statements</u>

40. The protestants produced five witnesses: Geoffrey Leking, an environmental scientist and an employee of the Division's Environmental Bureau in its Hobbs District Office; Celey Keene, a chemist and laboratory director and quality

manager of the Cardinal Laboratories in Hobbs, New Mexico; Wiley Scott Brake, an employee of Xcel Energy; and Protestants Mr. Randy Smith and Mrs. Naomi Smith.

41. Mr. Leking testified that he helped Mr. Smith collect water samples on August 1, 2012, at the trailer from Mr. Smith's sink where Mr. Smith first encountered the smell of sulfur and that on this visit he surveyed the surrounding areas for potential sources of hydrogen sulfide. He sampled water from the main sink in the trailer by turning on the cold tap water until it filled a large jar and began to overflow and drained out of the sink. The odor of hydrogen sulfide began to become noticeable and grew in strength until after about five minutes when the personal hydrogen sulfide monitor held at the bottom of the sink recorded a concentration of 14 parts per million.

42. Mr. Leking testified that, after considering potential sources, he rated the potential sources of hydrogen sulfide in the Smiths' water from low probability to high probability as follows: public gas facilities, gas wells, pipelines, sources generating hydrogen sulfide through anaerobic bacteria such as pond bottoms, ditches sewer piping, septic leach fields, drinking water wells and the accumulation of animal waste. On cross-examination, Mr. Leking stated that when investigating the source of hydrogen sulfide contamination that anaerobic bacteria is a high probability source. Mr. Leking said he did not consider nearby plugged and abandoned producing wells to be likely sources of hydrogen sulfide in Mr. Smiths' well water. On cross-examination, he testified that the nearby Maddox Lake is a highly probable source of hydrogen sulfide in the Smiths' well and that it is not "not probable" that acid gas from the Plant injection could reach the Smiths' groundwater well.

43. Mr. Leking testified that in October 2011 the hydrogen sulfide in Mr. Smith's water disappeared, but then re-appeared in April 2012.

44. Mr. Leking testified on cross-examination that there are high levels of sulfates in the groundwater in the area that are available to anaerobic bacteria to reduce to hydrogen sulfide if conditions in the subsurface and the well are anoxic. He further testified that measurements showing fluctuating levels of sulfides, a proxy measurement for hydrogen sulfide in water, together with high levels of sulfates point towards anaerobic activity as the potential source for the hydrogen sulfide smell in the Smiths' well water.

45. He testified that if groundwater wells completed in the same water-bearing formations approximately the same distance as the Smiths' water wells from the AGI No. 1 well injection do not show any indication of hydrogen sulfide contamination, that it would tend to support the conclusion that the hydrogen sulfide in the Smiths' wells is more likely due to anaerobic bacteria than from acid gas injection.

46. Ms. Keene testified that she analyzed four water samples delivered to her laboratory by the Smiths from July 2011 through October 2011. The first sample from July 2011 was analyzed for sulfate and total sulfide. The sulfates were recorded at 464 milligrams per liter and the sulfides registered as non-detect because the sample was not

collected and preserved properly to retain any hydrogen sulfide in the water. In August 2011, Ms. Keene testified that she tested two separate samples, one with a preservative for hydrogen sulfide and one without. The sample without preservative registered no sulfide, but the sample with preservative measured 0.634 milligrams per liter. Ms. Keene testified that this positive measurement demonstrated that hydrogen sulfide is present in the water that was sampled. In October 2011, Ms. Keene tested a fourth water sample for sulfate-reducing bacteria, which was analyzed by a sub-contracting laboratory, and the result indicated sulfate-reducing bacteria were not present in the sample.

47. On cross-examination, Ms. Keene testified that the fact that the October 2011 sample was negative for bacteria did not indicate that the source of the hydrogen sulfide in the Smiths' water was not bacteria, because hydrogen sulfide generated by bacteria can persist in groundwater without bacteria being present. She further testified that the source of hydrogen sulfide contamination is possibly sulfate-reducing bacteria if bleach poured down a well eliminates the hydrogen sulfide smell.

48. Mr. Smith testified that he placed a new trailer on his property in April 2011 and that within two weeks of living in the trailer his ranch hand said that the water smelled of hydrogen sulfide. After bleaching the well, the smell disappeared but re-appeared after about two weeks. Mr. Smith testified that his wife then poured four gallons of bleach into the well, but that the hydrogen sulfide smell returned after some uncertain time. On cross-examination, Mr. Smith testified that he poured two gallons into the well the first time he treated the well.

49. Mr. Smith testified that he measured fluctuating hydrogen sulfide levels in the trailer's sink over time using his personal hydrogen sulfide monitor. Hydrogen sulfide levels were very low in January 2012 until the end of April 2012, when the levels increased again. On cross-examination, he testified that the fluctuations ranged from 3 parts per million to 20 parts per million.

50. Mr. Smith testified that the Maddox Lake has been dry for three years, but that it had been stocked with fish by the State Department of Game and Fish and that when it was full of water people visited the lake to fish and swim. He further testified that he irrigates his fields, located to the north of his trailer and his domestic well, with a pivot irrigation system using water from the Xcel Maddox Energy Plant. On cross-examination, Mr. Smith testified that he uses potash fertilizer, which contains calcium sulfate, on his fields.

51. Mr. Smith testified that he is concerned about the hydrogen sulfide in his domestic water well and that the hydrogen sulfide will contaminate his other irrigation and domestic wells, as well.

52. On cross-examination, Mr. Smith testified that the trailer has a cement septic tank and a leach line running about 100 feet from the trailer and that the domestic well that serves the trailer is a couple hundred feet from the septic leach line to the north. Mr. Smith testified that he believes the leach line is down-gradient from the domestic

well. Mr. Smith testified that the domestic well that serves the trailer is about 160 feet deep, but that the water level in the well is about 50 feet deep.

53. Mr. Smith testified that when he has tried to call the DCP Plant he reached an employee in Denver, rather than an employee at the Plant.

54. Mr. Brake testified that he measured more than 100 parts per million hydrogen sulfide from Mr. Smith's sink faucet using his hydrogen sulfide monitor.

55. Mr. Brake testified that Xcel does not currently conduct any monitoring related to Maddox Lake. On cross-examination, Mr. Brake testified that Xcel does have six shallow monitoring wells, several of which are southeast of Maddox Lake and between Mr. Smith's irrigation pivots the AGI No. 1 well, and that, while there are sulfates in the groundwater, the monitoring wells have not detected any fluctuation in sulfates over time. He further testified that he does not know whether conditions in the subsurface below Maddox Lake are anoxic or anaerobic. Mr. Brake also testified that groundwater in the area flows in a southeasterly direction and that it is highly unlikely that any groundwater would flow north, even under the influence of groundwater well pumping for irrigation and other purposes.

56. Mr. Brake testified that based on the location of the Goodwin No. 3 well, approximately 300 feet north of Mr. Smith's water well, that it would be very unlikely Mr. Smith's well could pull contamination up gradient from the Goodwin No. 3 if it were a conduit for hydrogen sulfide from DCP's acid gas injection.

57. Mrs. Smith testified that when DCP's perimeter monitors appeared to be going off she called DCP twice, once in June or July of 2012 and once in November of 2012, using the numbers in the hydrogen sulfide contingency plan book provided by DCP but was unable to reach anyone at the phone numbers provided. Mrs. Smith testified that she kept calling numbers until she was able to reach someone.

Applicant's Rebuttal Evidence

58. On rebuttal, Mr. Gutiérrez testified that in his opinion DCP has established that it can safely and reliably operate the proposed AGI No. 2 well; that the AGI No. 1 well has not threatened the safety or health of neighboring land owners, nor has it impaired the environment; and that the Lower Bone Spring formation can and does contain the acid gas that has been and will be injected through the AGI No. 1 well and the proposed AGI No. 2 well.

59. Mr. Gutiérrez further testified on rebuttal that the Lower Bone Spring formation is one of the best reservoirs for receiving acid gas injection that he has evaluated: it has approximately 3,000 feet of caprock in the Abo, within the upper portion of the Bone Spring formation, above which is approximately 600 feet of the under-pressured Brushy Canyon formation, above which lies another 3,000 feet of alternating formations, some of which are sour and producing, and above which is another 1,200 feet

of salt in the Castillo and Salado formations, above which are the freshwater zones of the Dockum Group.

60. Mr. Gutiérrez testified that the casing and tubing integrity of the AGI No. 2 is assured by the enhanced design and materials that DCP proposes, such as down-hole sensors, and by the ongoing monitoring that is proposed. A second injection well will increase the Plant's overall reliability and prevent the un-planned shut-in of thousands of producing wells in the area.

61. Mr. Gutiérrez testified that acid gas injected through the AGI No. 1 well would have to travel more than 4,000 feet horizontally and more than two miles directly to the base of the Smiths' well to contaminate it. Based on a conservative injection rate of 4 million cubic feet per day, which is more than is actually injected on a daily basis, Mr. Gutiérrez calculated that the injection radius of the acid gas in the Lower Bone Spring formation to date is approximately only 480 feet from the point of injection and so could not have reached the Smiths' well.

62. Mr. Gutiérrez testified that any injected fluid that happened to escape the under-pressured injection zone and migrate through 3,000 feet of caprock would be trapped in the under-pressured and lost-circulation zone of the Brushy Canyon formation. These formations, and another 3,000 feet of productive formations above them, are capped by the Castillo and Salado salt formations, which are approximately 1,200 feet thick and have been used as a geologic repository to contain nuclear waste at the Waste Isolation Pilot Plant. Based on this geology, Mr. Gutiérrez testified that he cannot conceive of a way that DCP's injected acid gas could migrate to contaminate the Smiths' well.

63. Mr. Gutiérrez further testified that the intermittent and fluctuating sulfide detections reported by Mr. Smith and the fact that bleach eliminates the hydrogen sulfide smell are diagnostic that the hydrogen sulfide in the Smiths' well results from biological activity or from within the plumbing and not from DCP's acid gas injection.

64. Mr. Gutiérrez testified that DCP took two water samples from two different wells—the Eunice North and the No. 6 water well—at approximately the same distance as the Smiths' well from the AGI No. 1 well and completed in the same water-bearing formations and, using a preservative, recorded no sulfides in the samples. He testified that the only well in the area that has tested positive for hydrogen sulfide is Mr. Smith's well. However, Mr. Gutiérrez stated that the wells tested by DCP, as well as the monitoring wells operated by Xcel, all show high sulfate levels. Mr. Gutiérrez testified that when high sulfate water is exposed to anoxic conditions, the sulfate can be reduced to hydrogen sulfide by anaerobic bacteria. Based on the testimony and evidence presented at the hearing, Mr. Gutiérrez testified that it is his opinion that the water in Mr. Smith's well experiences anoxic periods that result in the generation of hydrogen sulfide.

65. In summary, Mr. Gutiérrez testified that the groundwater gradient, flowing to the southeast as testified by Mr. Brake, would transport injected acid gas away from

Mr. Smith's well; that if the water serving Mr. Smith's well is subjected to intermittent reducing conditions, there are high levels of sulfate in the water available to generate hydrogen sulfide; and that there are numerous potential sources for reducing conditions, such as Maddox Lake and Mr. Smith's leach line, and that hydrogen sulfide is a persistent and common problem in water wells throughout southeastern New Mexico. He testified that a biological source for the Smiths' contamination is much more likely and explains the elimination of the hydrogen sulfide smell in Mr. Smith's well when it is treated with bleach. Mr. Gutiérrez testified that it is unlikely hydrogen sulfide injected in the Lower Bone Spring formation to date, occupying an area with a radius of approximately 480 feet, could reach the freshwater zones in the Dockum Group. Mr. Gutiérrez further testified that DCP is injecting 18 percent hydrogen sulfide and 82 percent carbon dioxide and there is no evidence carbon dioxide is reaching the groundwater or the surface, where such concentrations would result in dead vegetation.

<u>The Commission's Conclusions</u>

66. Based on the evidence presented, the Commission cannot conclude that there is a connection between the hydrogen sulfide injected through the AGI No. 1 well and the contamination at the Smith's groundwater well.

67. The Commission concludes that injection of acid gas through the AGI No. 2 well, subject to the conditions provided in this Order, can be conducted in a safe and responsible manner without causing waste, impairing correlative rights, or endangering fresh water, public health, or the environment.

68. Given the toxic nature of acid gas and the experience of the AGI No. 1 well, the Commission concludes that specific measures are necessary for both the AGI No. 1 and AGI No. 2 wells to ensure protection of public health, the environment and correlative rights.

69. The new proposed location at 1600 feet from the South line and 1750 feet from the West line (Unit K) of Section 30 is a preferred location and the C-108 shall be modified to reflect this amended surface location.

<u>IT IS THEREFORE ORDERED THAT:</u>

A. DCP Midstream, LP is hereby authorized to drill and complete the proposed Linam Ranch AGI No. 2 well, to be located 1600 feet from the South line and 1750 feet from the West line (Unit K) of Section 30, Township 18 South, Range 37 East, NMPM, in Lea County, New Mexico, in such a manner as to permit the injection of acid gas, consisting principally of carbon dioxide and hydrogen sulfide, for disposal into the Lower Bone Spring formation at a depth interval of approximately 8,700 feet to 9,100 feet below the surface through 3 1/2-inch tubing set in a packer located at approximately 8,650 feet below the surface.

B. AGI No. 2 Well. The operator of the AGI No. 2 well (Applicant or any successor operator) shall take all steps necessary to insure that the injected gas enters only the proposed injection interval and does not escape to other formations or onto the surface.

C. The AGI No. 2 well shall be constructed substantially in accordance with the description in the Injection Well Data Sheet attached to Form C-108 filed by the Applicant in this case as modified by the final well location and the final well design presented in the hearing, including setting surface casing approximately 500 feet below the surface and setting a total of four casing strings, all with cement circulated to the surface.

D. Copies of any logs of the completed AGI No. 2 well and a letter setting forth the estimated static bottomhole pressure of the injection formation shall be delivered to the Division's Hobbs District Office prior to commencement of injection.

E. After installation of the injection tubing but prior to commencing injection operations at the AGI No. 2 well, the operator shall pressure test the casing from the surface to the packer-setting depth to assure casing integrity.

F. DCP shall be required to conduct a mechanical integrity test on the AGI No. 2 well from the surface to the packer-setting depth once every year

G. The operator shall notify the Hobbs District Office of the Division of the time of the setting of the tubing and packer and of any mechanical integrity test so that such operations can be witnessed or inspected.

H. The casing-tubing annulus of the AGI No. 2 well shall be loaded with diesel fluid treated with corrosion inhibitors and biocides and equipped with a pressure gauge or approved leak-detection device to detect any leakage in the casing, tubing, or packer.

I. The operator shall insure that the injected gas is properly dehydrated prior to entering the injection zone.

J. Thirty days prior to commencing injection at the AGI No. 2 well, the operator shall coordinate with the Division to establish immediate notification parameters for annulus pressure and tubing and casing differential pressure at a set injection temperature.

K. Ninety days after commencing injection at the AGI No. 2 well, the operator must review the pre-injection immediate notification parameters with the Division. If the Division determines that the parameters require modification, new immediate notification parameters shall be developed and implemented in coordination with the Division.

L. The immediate notification parameters shall be reviewed jointly by the operator and the Division periodically, but not less than once a year.

M. The operator shall record injection rates and pressures on a continuous basis and report these readings annually, or at any time if requested, to the Engineering Bureau in the Division's Santa Fe Office and to the Division's Hobbs District Office. Each such report shall include the well name, location, API Number and the number of this order.

N. If DCP identifies an anomaly under the parameters administratively set by the Division, DCP shall provide the previous months' continuously gathered data to the Division for analysis and review.

O. The injection well or system at the AGI No. 2 well shall be equipped with a pressure limiting device that will limit the wellhead pressure on the injection well to no more than 2,644 psi while injecting acid gas with an approximate specific gravity of 0.8. The operator shall attempt to maintain the injected fluid in the non-corrosive phase with minimum pressure regulating devices as necessary.

P. The Director of the Division may authorize an increase in injection pressure upon a proper showing that such higher pressure will not result in migration of the injected gases from the permitted injection formation. Such showing shall consist at least of a valid step-rate test run in accordance with procedures acceptable to the Division. Any step-rate test shall be run with an inert fluid, such as produced water, and not with acid gas.

Q. Without limitation of the duties of the operator, as provided in Division Rules 19.15.19 and 19.15. 29 NMAC, the operator shall immediately notify the Hobbs District Office of the Division of any failure of the tubing, casing, or packer in the well, or any leakage or release of water, oil or gas from or around any producing or plugged and abandoned well in the area, and shall take such measures as may be timely and necessary to correct such failure or leakage.

R. The proposed acid gas pipeline system shall be buried at least three feet below the surface. All road crossings shall be installed in conduits designed and constructed to prevent damage due to traffic or routine road maintenance. The pipelines shall be constructed and maintained as if they were subject to United States Department of Transportation rules. Pipeline markers shall alert the public to the presence of poisonous gas.

S. Prior to commencing injection at the AGI No. 2 well, the operator shall submit to the Engineering Bureau in the Division's Santa Fe Office written evidence of satisfaction of the conditions precedent to injection provided in this order and obtain an administrative order acknowledging compliance with those conditions and authorizing commencement of injection.

T. The operator shall submit monthly reports of injection volumes to the Division on Form C-115 in accordance with Division Rules 19.15.26.13 and 19.15.7.24 NMAC.

U. The injection authority herein granted shall terminate two years after the effective date of this order if the operator has not commenced injection operations pursuant hereto; provided however, the Division Director, upon written request of the operator, may extend this time for good cause shown.

V. Compliance with this order does not relieve the operator of the obligation to comply with other applicable federal, state, or local laws or rules, or to exercise due care for the protection of fresh water, public health and safety and the environment.

W. Prior to commencing injection at the AGI No. 2 well, the operator shall prepare and secure approval by the Division's Environmental Bureau of a hydrogen sulfide contingency plan that complies with Division Rule 19.15.11.9 NMAC for the AGI No. 2 well, including any necessary changes are made under the current plan for the AGI No. 1 well to correct all contact numbers and the plans are provided to the Smiths and the Xcel Maddox Station.

X. AGI No. 1 Well. The conditions for the construction and operation of the AGI No. 1 well provided in Order No. R-12548, as amended, shall remain in effect except as amended and supplemented by this Order.

Y. The operator shall, sometime after AGI No. 2 begins to receive injected acid gas, work over AGI No. 1 to install an additional packer in the AGI No. 1 well above the existing packer, and to upgrade the well, to the extent feasible, with a tubing string, annular fluid (diesel fluid treated with corrosion inhibitors and biocides), and down-hole monitoring sensors similar to what has been installed in the AGI No. 2 well. This includes the installation of a limited section of corrosion resistant tubing in the depth interval immediately above the new, stacked packer.

Z. This Order hereby modifies Order No. R-12546-I to require that DCP also shall conduct a mechanical integrity test on the AGI No. 1 well from the surface to the packer-setting depth every year instead of every two years, as previously required; provided, however, that the operator shall continue to conduct a mechanical integrity test on the AGI No. 1 well every six months until a new packer is successfully placed in the AGI No. 1 well and the Division authorizes mechanical integrity tests once every year.

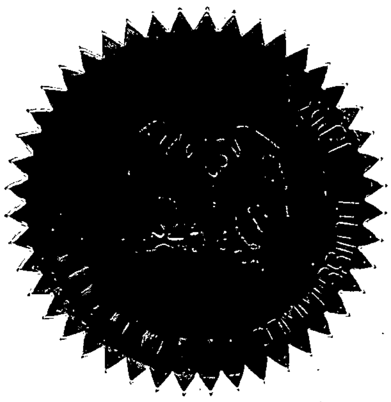
DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ROBERT BALCH, Member

TERRY WARNELL, Member

JAMI BAILEY, Chair



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