DEVON EXHIBIT C

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

APPLICATION OF FOUNDATION ENERGY MANAGEMENT, LLC FOR APPROVAL OF A SALT WATER DISPOSAL WELL IN LEA COUNTY, NEW MEXICO.

CASE NO. 21145

TESTIMONY OF ALEX BERNHARD

1. My name is Alex Bernhard, and I am a drilling engineer with Devon Energy Production Company, L.P. ("Devon").

2. I have not previously testified before the New Mexico Oil Conservation Division. I have attached my resume as **Devon Exhibit C-1**, which provides an overview of my educational background, work history and training, and the professional associations in which I am involved. I believe that these credentials, with my experience and training, qualify me to testify as an expert witness in drilling engineering.

3. I am familiar with the application filed by Foundation Energy Management, LLC ("Foundation") in this case and have conducted an analysis of the potential impacts on Devon's existing wells and its planned drilling program for additional wells in the area of the proposed injection.

4. The proximity of Foundation's proposed injection into the Delaware Mountain Group through the Blue Quail Federal #1 Well presents a substantial risk to the wellbore integrity of Devon's wells targeting productive intervals within the deeper Bone Spring and Wolfcamp formations. My testimony will provide an overview of the risks and impacts to production wells associated with injection into the Delaware Mountain Group, followed by an evaluation of the additional costs that will be imposed on Devon's drilling program in the area based on Devon's

recent experience with its Boundary Raider 6-7 Fed Com 711H well (API No. 30-025-47571) in Section 6, Township 31 South, Range 32 East and impacts from an offsetting Delaware Mountain Group saltwater disposal well.

5. For Devon's wells that target the Bone Spring formation, after setting 9-5/8" intermediate casing to isolate the Salado and Castile formations, the subsequent section of hole starting in the Delaware Mountain Group is drilled on a freshwater mud system. Foundation's proposed injection through the Blue Quail Federal #1 would cause injected produced water, because it is a greater in density than virgin formation fluid and injected above pore pressure, to enter Devon's wellbore during drilling. The heavier weight injected produced water would either return to the surface with Devon's drilling fluids and be seen in the pit volume totalizer as an influx/kick, or it would travel further downhole and crossflow into the underlying formations. These impacts could cause Devon to have to "shut in" on the wellbore with BOP equipment or increase the drilling fluid weights used to hold back any influx/kick. It could also result in losing returns in the Delaware Mountain Group due to the active mud system increasing in density from the invasion of injected produced water flows creating an excess of hydrostatic pressure on the open hole, exceeding the fracture gradient of the formation.

6. The final step in the drilling process for Bone Spring formation wells requires tying back the production casing cement to the intermediate casing, sealing off any open hole and protecting the casing strings behind a protective cement sheath, which is something that both the BLM and OCD require operators to do. However, if injected produced water flows are present below the intermediate casing shoe in the injection interval, they will likely enter the wellbore during the cement job and contaminate the column of cement. Invasion of injected produced water flows into the cement slurry will both degrade the quality of the cement bond to the casing and formation, as well as create channeling within the cement. Both of these problems form pathways

for corrosive and sour formation fluids to contact exposed casing, leading to corrosion and hydrogen embrittlement over time. Channeling that occurs in the cement sheath not only puts the casing string at risk, but also provides a conduit for the injected produced water to reach deeper, still prospective formations below, including Devon's development targets in the Bone Spring and Wolfcamp formations. This raises the potential for creating a corrosive/sour environment as well as watering-out hydrocarbon bearing formations.

7. Foundation's proposed injection also will contaminate existing formation fluid by increasing the corrosivity and hydrogen sulfide content, increasing the risk of impacts due to corrosion and hydrogen embrittlement. Foundation's C-108 shows that the water chemistry samples for Foundation's producing source wells from which produced water will be injected into the Delaware Mountain Group all have higher concentrations of carbon dioxide and hydrogen sulfide than the receiving formation fluids in the Delaware Mountain Group. In addition, produced water injected from the surface can be expected to contain concentrations of surface microbes that have the potential to continuously generate hydrogen sulfide in the downhole anoxic environment. This means that with the proposed injection, the Delaware Mountain Group formation fluid around Devon's existing and proposed wells will become increasingly corrosive and sour over time, exposing Devon's existing wellbores and proposed wells to greater risk.

8. For Devon's wells that target the Wolfcamp formation, Devon uses a lightweight diesel-brine emulsion as the active mud system in the intermediate section when drilling from the top of the Rustler, just below surface casing, to intermediate TD in the Third Bone Spring Sand. This drilling fluid system costs approximately $150,000 to $250,000 depending on the well and the circumstance. It allows Devon to achieve lighter densities that fit within the appropriate mud density window, holding back formation pressure but not exceeding fracture gradients. Achieving the correct drilling fluid density is a delicate balance. Heavy brines introduced into the system as

a result of produced water injection, as Foundation proposes, put the system at substantial risk. The heavier weight injected produced water flows from the proposed injection will increase the mud's density and could cause a complete loss of drilling fluid returns to a weak zone, break the diesel-brine emulsion itself or, at a minimum, require Devon to add a substantial amount of diesel and mud product to maintain proper specifications within the system.

9. As with Bone Spring formation wells, BLM and OCD requires operators to properly cement Wolfcamp casing strings. For Devon's 8-5/8" intermediate casing in its Wolfcamp formation wells, that means it must be cemented from the casing shoe to the surface. As with cementing the production casing for Bone Spring wells, discussed above, cementing intermediate casing for Wolfcamp formation wells through a produced water injection plume in the Delaware Mountain Group creates significant risk. The same factors and risks outlined in Paragraphs 6 and 7 above are applicable to cementing intermediate casing in Wolfcamp wells within the Delaware Mountain Group. However, this cement job has an additional, critical component that is not present in the production cement on Bone Spring wells. On a Bone Spring well, there is already a string of cemented casing covering the salt interval before this crucial cement job; on Wolfcamp wells there is not. That means the intermediate cement job must adequately protect the 8-5/8" intermediate casing from saltwater corrosion.

10. Invasion of heavy weight injected produced water flows into the wellbore during the intermediate casing cement job also could prevent cement from circulating to the surface. If an operator is unable to circulate cement all the way to the surface, both the BLM and OCD require the operator to remediate the cement job, which can cost approximately $20,000 to $30,000 for materials alone. After the remediation, the operator is required to verify the efficacy of said remediation, which incurs further costs and lost rig time.

11. **Devon Exhibit C-2** is a map showing cumulative water production volumes for producing wells in the lighter blue circles and cumulative water injection volumes for Delaware Mountain Group saltwater disposal wells in the darker blue/purple circles. The diameter of the circles is relative to the volume of water—the larger the volume the larger diameter the circle. As with Exhibit B-2 and B-3, the red squares depict the locations of Devon's existing well pads. The green squares depict the locations of Devon's existing surface facilities.

12. Of note, in the southwest corner of Section 31 (Unit M), Township 22 South, Range 32 East, is a saltwater disposal well, the Silverton 31 Federal #1 (API No. 30-025-32093). Since 2004, it has injected a cumulative total of 1,119,035 million barrels of produced water into the Bell Canyon formation of the Delaware Mountain Group—the same injection interval that Foundation proposes for its Blue Quail Federal #1 well. The Silverton 31 Federal #1 remains an active disposal well in the Bell Canyon formation.

13. In Section 6, Township 31 South, Range 32 East, which is immediately south of the Silverton 31 Federal #1 disposal well, Devon has several existing well pads along the north line of that Section. After receiving an approved federal APD in August 2020, Devon recently drilled its Boundary Raider 6-7 Fed Com 711H well (API No. 30-025-47571) from the well pad in the far northwest corner of Section 6. During the drilling of the vertical portion of that wellbore, Devon encountered significant difficulties directly attributable to the offsetting disposal from the Silverton 31 Federal #1.

14. **Devon Exhibit C-3** is a spreadsheet which contains a partial breakdown of the costs that were incurred to safely and successfully complete drilling the intermediate hole section of the Boundary Raider 6-7 Fed Com 711H well, using what is commonly referred to a "managed pressure drilling" program or MPD. Highlighted in yellow are the additional costs incurred to Devon for having to use an MPD program that are directly caused by the produced water flows

from the offsetting Silverton 31 Federal #1 disposal well encountered during drilling operations. In total, the additional costs directly attributable to managing the produced water flows were $101,527 for a single well. This system is necessary to keep the active mud system light enough to not exceed the fracture gradient of any formations, but also hold back pressure on connections and trips to prevent influxes of injected produced water.

15. The vertical portion of the Boundary Raider 6-7 Fed Com 711H wellbore is located approximately 900 feet from the Silverton 31 Federal #1. Offsetting Foundation's proposed injection, Devon plans to drill at least 23 additional wells targeting prospective Bone Spring and Wolfcamp intervals within one-half mile of Foundation's Blue Quail Federal #1 well over the next five years. Devon plans to drill some of these wells from the Boundary Raider 7 Well Pads 1 and 2 that are located 268 feet and 455 feet, respectively, from the Blue Quail Federal #1 well. That is much closer to the source of produced water flows than the Boundary Raider 6-7 Fed Com 711H wellbore is to the Silverton 31 Federal #1 disposal well. That proximity means that once Foundation starts injecting the offsetting wells Devon plans to drill will likely encounter produced water flows from Foundation's proposed injection, given the short offset distance.

16. Based on the Boundary Raider 6-7 Fed Com 711H experience, Devon expects to incur at least an additional $2.3 million, or an extra $100,000 per well, just to manage its drilling operations through Foundation's injection plume for the wells it plans to drill within a half-mile radius over the next five years, based on current dollars. But the additional costs to Devon's drilling program as a result of Foundation's proposed injection could be much higher if use of an MPD program like the one used to drill the Boundary Raider 6-7 Fed Com 711H is insufficient, as mentioned in paragraph 8, above.

17. **Devon Exhibit C-4** is a spreadsheet that contains a partial breakdown of the costs associated with drilling Devon's Shetland 11-2 Fed State Com 711H Well (API No. 30-015-

47156) in Section 11 (Unit M) of Township 26 South, Range 31 East. The Shetland well is completed in the Wolfcamp formation. The Shetland well costs are representative of what would be required to build and maintain a system of diesel-brine emulsion. The up-front cost of the full volume, plus the additions of products and diesel while drilling is substantial. The analogous costs in Exhibit C-4 are highlighted in yellow and total $294,363.92. These costs demonstrate the potential spend if the well went on full lost returns due to an influx of injected produced water and would be in addition to the cost of the MPD program.

18. Besides increasing costs and elevating risks, Foundation's proposed injection impairs Devon's correlative rights by making it less practicable and technically more difficult to access and develop its mineral interests in the Bone Spring and Wolfcamp formations. The proposed injection also increases the risk of premature abandonment due to the loss of a casing string from hydrogen embrittlement or corrosion, that could result in lost reserves.

19. Exhibits C-1 through C-4 were prepared by me, under my direct supervision, or they constitute Devon business records.

20. To protect its correlative rights and prevent waste, Devon requests that the Division deny Foundation's application.

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