Expert Evaluation of the D.A. Hughes Collier-Hogan 20-3H

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Well Drilling and Workover

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GOVERNMENT RELATIONS · ENERGY · PLANNING · TECHNOLOGY
ENGINEERING · ENVIRONMENTAL

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List of Acronyms and Abbreviations

AECOM	AECOM Technical Services, Inc.
ALL	ALL Consulting, LLC
API	American Petroleum Institute
bbl	barrel
bbl/d	barrel(s) per day
BHA	bottom hole assembly
BHTP	bottom-hole treatment pressure
bls	below land surface
BOP	Blowout Preventer
bpm	barrels per minute
CBL	Cement Bond Log
DA Hughes	Dan A. Hughes Company, L.P.
DF	Derrick Floor (aka, drilling rig floor)
DMW	deep monitoring well
F.A.C.	Florida Administrative Code
FAS	Floridan Aquifer System
FDEP	Florida Department of Environmental Protection
FDEP SIS	Florida Department of Environmental Protection Site Investigation Section
FIT	Formation Integrity Test
FTP	file transfer protocol
HRP	HRP Associates, Inc.
HVHF	High Volume Hydraulic Fracturing
IAS	Intermediate Aquifer System
ISIP	instantaneous shut-in pressure
LCM	lost circulation material
LCZ	lost circulation zone
LFAS	Lower Floridan Aquifer System
MD	measured depth
MFCU	Middle Floridan Confining Unit
MIT	mechanical integrity test
MSL	mean sea level
MTD	measured total depth
O.D.	outer diameter
PE	Professional Engineer
ppg	pounds per gallon
ppm	parts per million
psi	pounds per square inch

psig	pounds per square inch gauge
PTAC	Petroleum Technology Alliance Canada
R_m	mud resistivity
SAS	Shallow Aquifer System
SCEK	Science and Community Environmental Knowledge Fund
SDWS	Secondary Drinking Water Standard
SWPPP	Storm Water Pollution Prevention Plan
TD	total depth
TDS	Total Dissolved Solids
TIH	tripped in the hole
TVD	true vertical depth
UAS/UCU	undifferentiated aquifer systems and confining units
UFAS	Upper Floridan Aquifer System
USDW	Underground Source of Drinking Water
U.S. EPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey

1 Witness Statement and Qualifications

1.1 Witness Statement

ALL Consulting, LLC, (ALL) was retained by the Florida Department of Environmental Protection (FDEP) to review information and offer an expert opinion concerning the Dan A. Hughes Company, L.P., (DA Hughes) Collier-Hogan 20-3H oil well (hereinafter simply referred to as the Collier-Hogan 20-3H) and the workover procedure performed on it from December 30, 2013, to January 1, 2014. The overall purpose of this effort was to evaluate whether the workover procedure was designed and carried out in such a way that it was not likely to result in violations of applicable groundwater quality standards in the freshwater aquifers present at the wellsite.

1.1.1 File Review

ALL performed a file review of documents and information provided by FDEP related to the drilling and completion of the Collier-Hogan 20-3H oil well. This included, but is not limited to, various inspection records, geophysical logs, photographs, reports, cementing records, plugging records, and monitoring data. Review of this data revealed the following issues of particular significance:

- Surface Spills/Releases,
- Lost Circulation Zones,
- Surface Casing Setting Depth,
- Surface Casing Cementing Records, and
- Test pressures vs. stimulation pressures.

1.1.2 Site Inspection

A site inspection was performed at the Collier-Hogan 20-3H well site. Dan Arthur of ALL was not provided access to enter the well site, but was provided access to the exterior boundary of the well pad. During this site inspection, it appeared that representatives of DA Hughes were disassembling equipment on the pad. Overall, Mr. Arthur did not observe any significant issues during the inspection. Selected items of particular significance that were observed during the site inspection include the following:

- **Containment**: The well pad was observed to have a berm around the entire exterior boundary. A portion of the berm was removed to allow storm water to drain from the site after the apparent cessation of production operations.
- **Vegetation**: Based on a complete inspection around the entire pad, no stressed vegetation that appeared to be a result of operations at the Collier-Hogan 20-3H was observed. Considering that fluids handled at an unconventional well site may be very high in chloride concentration, releases from the site would likely have stressed surrounding vegetation.
- **Wellhead Pressure**: Although Mr. Arthur was not permitted access to the interior of the well pad, valves and gauges at the wellhead were visible. Binoculars were used to

confirm that the gauges at the wellhead all read approximately 0 psig and valves to the well annulus (i.e., to the gauges being viewed) appeared to be open.

- **Well Pad**: Review of past information and aerial photographs confirmed that there had been spills or releases at the site. Inspection of the well pad suggested that any and all spills had been cleaned up and new surface material had been placed on the pad.

1.1.3 Geology and Groundwater Assessment

An assessment of the area geology was performed and included review of available logs and drill cuttings from the Collier-Hogan 20-3H as well as geological information from the area, including Collier, Hendry, and Lee Counties. The following findings are particularly relevant to this review:

- **Vertical Separation**: The lower Sunniland Formation, which was the targeted producing formation for the Collier-Hogan 20-3H, is located at approximately 12,000 feet below land surface (bls). The estimated depth of the lowermost underground source of drinking water (USDW) in the area is approximately 1,850 feet bls. This creates a vertical separation of more than 10,000 feet, or nearly two (2) miles.
- **Intervening Confining Zones**: There are numerous low permeability strata between the top of the Sunniland Formation and the base of the USDW. Most notable among these are the anhydrite beds within the immediately overlying Lake Trafford Formation. There are numerous additional confining strata overlying the Lake Trafford Formation including carbonates and anhydrites.
- **Boulder Zone**: As a complement to the vertical separation between the oil production horizon and the lowermost USDW, South Florida has an extremely high permeability zone that exists between the production zone and lowermost USDW. The "Boulder Zone" is perhaps one of the most highly permeable geologic formations in the United States and is used for purposes of injection disposal in South Florida. The "Boulder Zone" is under-pressured and would likely serve as a receiving or thief zone in the unlikely event that fracturing fluids or formation waters migrated vertically upwards from the lower Sunniland Formation as a result of unconventional resource development.
- **Existing Production**: As noted above, the target formation for the Collier-Hogan 20-3H was the lower Sunniland Formation. The Sunniland Formation is a vertically compartmentalized stratum with multiple oil production intervals. Historical oil production in South Florida has occurred in the upper portions of the Sunniland. As such, depending on the location, these zones in the upper Sunniland could be under-pressured and have the potential to serve as thief zones to any fracturing fluids or formation waters in the unlikely event that such were to migrate vertically upward from the lower Sunniland Formation.
- **Vertical Propagation of Induced Fractures**: Hydraulically induced fractures have been demonstrated to rarely extend more than 1,000 feet vertically upwards. Baker Hughes' modeling of the workover procedure performed on the Collier-Hogan 20-3H indicates that the maximum fracture height was only about 14 feet above the wellbore lateral.
- **Limited Extent of Vertical Fractures**: Considering the presence of approximately 10,000 feet of intervening strata between the targeted lower Sunniland Formation and the

base of the USDW and also the presence of multiple confining strata and low pressure zones within that intervening stratigraphic section, induced fractures, and hence hydraulic fracturing fluids or formation waters, could not have reached the USDW.

- **Groundwater Quality**: Based on June 2014 sampling results from shallow groundwater monitoring and supply wells, there is no indication that fluids injected during the workover procedure at the Collier-Hogan 20-3H well resulted in adverse impacts to the Shallow Aquifer System (SAS) exceeding applicable drinking water standards.

1.1.4 Collier-Hogan 20-3H Workover

Issues in question related to the workover that were considered and addressed include:

- Whether this procedure (or similar future procedures) was designed and carried out in such a way that it was not likely to cause or contribute to violations of applicable groundwater quality standards;
- The potential for fluids during the workover to migrate vertically upward into USDWs through deep geological formations, other abandoned wellbores, or the well itself.

First, DA Hughes had three completion designs prepared. The first one was an Acidizing Proposal designed by Baker Hughes. Some type of acid stimulation occurred on September 29, 2013, but there are no service company records documenting the type of treatment performed. The second proposed procedure was by Halliburton (October 21, 2013), but this proposal was withdrawn by DA Hughes on December 12, 2013. As a result, a third procedure was developed by Baker Hughes and submitted to FDEP on December 23, 2013. The Baker Hughes design included a seven (7)-stage stimulation. The Baker Hughes submittal was also complemented by information from Jeffery Ilseng, Operations Manager for DA Hughes. Mr. Ilseng's submittal included technical details about the well and specified a recommended procedure. The procedure included testing the stack to 10,000 pounds per square inch (psi) and other details common to stimulation procedures.

DA Hughes commissioned a report to analyze the workover at the Collier-Hogan 20-3H; that report was prepared by HRP Associates, Inc., (HRP) and completed in December 2014. The HRP report includes results of modeling using Baker Hughes' MFrac 3D Simulator. The subject model does not directly match either the proposal or the actual stimulation, but it does provide insights into the job. Page 2 of the simulation report estimates the maximum surface injection pressure to be 4,133.2 psi and the maximum bottom-hole treatment pressure (BHTP) to be 8,703.3 psi. Maximum fracture height was also estimated at 14.365 feet above the well horizontal section (this is well within the Sunniland Formation, true vertical depth estimated at 11,927 feet bls); total fracture height was estimated at 73.228 feet (14.365 feet above the lateral and 58.863 feet below the lateral). However, the simulation (i.e., modeling using the MFrac 3D Simulator) was performed using volumes for fluids and proppants that were less than what was used in the actual workover operations (i.e., modeling was not performed to match actual events).

The actual workover on the Collier-Hogan 20-3H well occurred from December 30, 2013, through January 1, 2014, as specified in the Baker Hughes Post-Stimulation Report. The Post-Stimulation Report is a record of the actual workover procedure and is not a plan or model. As such, this report includes data reflective of what was planned for the stimulation and how the stimulation was ultimately performed. Based on this record, there are several items that are relevant to the issue of assessing the workover procedure for purposes of ALL's report. These include, but may not be limited to, the following:

- **Stages**: The well was stimulated using a multi-stage treatment procedure that included a total of seven (7) separate stages in the horizontal portion of the wellbore.
- **Fluid Volumes**: The Baker Hughes report notes that a total slurry volume of 691,068 gallons of fluids were used for the seven (7)-stage workover.
- **Formation Breakdown**: Formation breakdown pressures approached approximately 9,000 psi with average treating rates ranging up to approximately 28.2 barrels per minute (bpm). Graphical recordings of pressures and other parameters are included in the report for each stage and clearly show (and annotate) a breakdown pressure during Stage 1 of 7,802 psi. Further, the signature of the pressure graph confirms this conclusion.
- **Hydraulic Fracturing**: With this information, it can be concluded with confidence that the workover on the Collier-Hogan 20-3H involved hydraulic fracturing of the formation on each of the seven (7) stages. Considering the volume of fluids used in all stages, in ALL's experience the subject workover would be considered multi-stage "High Volume Hydraulic Fracturing" (HVHF).
- **Irregularities**: Review of the various data and plots from the Post-Stimulation Report are common results for HVHF jobs. A detailed assessment of the subject data reveals no specific irregularities or data that would indicate a concern. Maximum BHTPs were noted to approach approximately 9,000 psi, but the scale of the charts made actual maximum values difficult to assess. Regardless, data records do not appear to suggest an abnormal formation reaction, well integrity loss, or other potentially concerning issues.

1.1.5 Collier-Hogan 20-3H Mechanical Integrity

The previously referenced HRP report (December 2014) includes a memorandum from "TH" dated November 25, 2014. The memorandum is brief and was written considerably later than well drilling and completion activities on the Collier-Hogan well, but it does provide some insights on Mechanical Integrity and other issues. In the memorandum, the author notes that each of the casing strings were pressure tested to roughly 1,000 pounds per square inch gauge (psig) prior to drilling out the cement plug at the casing shoe. This testing serves to confirm that the casing system likely had "Internal" Mechanical Integrity. The memorandum does not specify a duration for the test, pressure fluctuations, how the pressure was measured, or whether there was an actual record of the pressure test. Considering the fact that the memorandum was prepared approximately a year after these various tests, it is not possible to fully affirm this conclusion based on this memorandum. FDEP oil well inspection reports do document the following regarding mechanical integrity:

- Performed "successful" mechanical integrity test (MIT) of 13-3/8-inch surface casing at 1,000 psi (witnessed by drilling consultant);
- Performed MIT of 9-5/8-inch intermediate casing to 1,002 psi and lost 10 psi in 30 minutes (witnessed by P. Attwood of FDEP on February 12, 2013); and

- Performed MIT of 7-inch casing to 1,015 psi and gained to 1,031 psi in 30 minutes (witnessed by Mark Robert Jones, P.P.I. drilling consultant on April 21, 2013).

All three of these MITs were performed prior to drilling out of the cement in the bottom of the casing strings, so these tests did not confirm the integrity of the casing shoes.

In addition, other data are available that relate to integrity of the Collier-Hogan well. This includes well construction records, cement evaluation records, and other details. As also noted in the November 25, 2014, Memorandum from "TH" (HRP, December 2014), the following items are relevant:

- **13-3/8-inch Surface Casing**: The Surface Casing was set at 1,718 feet, which is shallower than originally planned. In an effort to confirm that the Surface Casing was set to an adequate depth, DA Hughes ran a resistivity log to estimate if the Casing was set through the lowermost USDW. FDEP reviewed the log and approved the setting depth. Additionally, DA Hughes faced challenges with cementing this casing string due to lost circulation and other wellbore issues, requiring topping off the cement job from the surface. A Cement Bond Log (CBL) was also run on this casing string and suggested very poor cement bonding, questioning the external mechanical integrity for this very important casing string. No returns were obtained during cementing, thus putting into question the external integrity of this casing string. Furthermore, although fluid returns were noted after the casing was set, a "Formation Integrity Test" (FIT) was apparently not performed on the casing shoe after the plug at the casing shoe was drilled out. It is important to note that although establishing fluid returns is a positive outcome, this observation does not replace a FIT.
- **9-5/8-inch Intermediate Casing**: During drilling, a lost circulation zone (LCZ) was encountered at 2,031 feet continuing to 3,965 feet with no returns to surface during drilling. The memo from "TH" notes that the Driller "drilled out shoe and tested casing to 11 ppg [pounds per gallon] mud." This test is presumably a FIT and would be a positive indication of integrity at the casing shoe.
- **7-inch Intermediate Casing**: The memo from "TH" notes that the Driller "drilled out and tested shoe to 10 ppg equivalent mud."
- **4-1/2-inch Production Casing**: Prior to the completion, the Production Casing was tested to "over 8,000 psi with no indications of communication with the annulus of any casing string."[1] It has become industry standard to pressure test the casing prior to HVHF for a variety of safety reasons. The Baker Hughes Workover Procedure design states that the casing would be tested to 10,000 psi. However, the only record of such actual testing is "over 8000 psi." Maximum pressures applied to the well during the HVHF approached approximately 9,000 psi. Standard industry practice would be to pressure test the casing and surface equipment to a pressure that exceeds the maximum pressure anticipated during the fracturing job. In this case, that does not appear to have happened. The fracturing event occurred at a pressure that appears to have exceeded the maximum testing pressure of the production casing. As such, pressures that were above testing pressures were applied to the casing during fracturing, without first determining if the actual pressure could be reached safely.

1.1.6 Wells 86 and 103 Plugging Records

Two plugged wells were identified in the vicinity of the Collier-Hogan 20-3H. Plugging and related records for the Permit 86 and 103 wells were reviewed. Both wells were rotary drilled into the Sunniland Formation to a depth of approximately 12,100 feet and were plugged and abandoned in the late 1940s. Specific observations pertaining to these two wells are as follows:

- **Permit 86**: This well was plugged with three (3) cement plugs in addition to the bottom-hole plug placed during drilling. The cement plugs were separated by heavy drilling mud. The heavy drilling mud plugs combined with the cement plugs and casing removed from the well during plugging operations should be adequate to prevent fluid movement up the plugged borehole and into the lowermost USDW, based on ALL's and Mr. Arthur's experience. Furthermore, re-entering the well to drill-out the cement plugs to investigate the well is **not** recommended.
- **Permit 103**: Unlike in the Permit 86 well, no pipe was removed for salvage in well 103. Permit 103 was plugged in 1949 with two cement plugs, but Humble attempted to re-enter the well in 1953. FDEP records note that during the unsuccessful re-entry the "Contractor could not drill out cement in top of same" and "well casing not disturbed." However, no records of whether the upper plug was compromised are available. In considering the risks posed by this well, it is important to recognize that there is a bottom-hole plug and heavy-weight mud overlying the bottom-hole plug. Vertical separation works in favor of risk mitigation, while the potential that the upper plug and 9-5/8-inch casing string may have been compromised is concerning. The absence of a top plug and the apparent lack of cement (or a demonstration of well-bonded cement) between the "Boulder Zone" and lowermost USDW are also concerning. As such, FDEP should consider assessing the integrity of the cement plug at 4,200 feet (approximately) and the 9-5/8-inch casing. Regardless, based on analysis of the specific technical details applicable to the Collier-Hogan 20-3H workover, it is not likely that opening and re-entering this well (Permit 103) would detect any contamination that may have migrated from the Collier-Hogan 20-3H to the Permit 103 well.

1.1.7 Deep Monitoring Well

In an effort to assess whether the workover procedure performed on the Collier-Hogan 20-3H resulted in violations of applicable groundwater quality standards, a deep monitoring well (DMW) is planned to facilitate sampling of the lowermost USDW. Considering that the depth to the lowermost USDW is approximately 1,850 feet bls, this effort is substantial and consideration of multiple monitoring wells is impractical. As such, a single well is planned, thus making the location of the well a priority. Various locations of the DMW were considered and assessed. For this situation, locating the DMW near the vertical portion of the wellbore was a priority. Further, locating the well in an area where surface disturbances could be minimized was also a priority. As such, a location west and slightly south of the Collier-Hogan 20-3H was selected and should suit FDEP's priorities pertaining to this investigation.

Based on the above, the following basic findings are supported:

- The existing monitoring well network installed by FDEP surrounding the Collier-Hogan 20-3H well pad does not indicate the presence of adverse impacts to shallow groundwater being monitored.
- Considering the various site-specific and regional technical considerations, it appears improbable that the lowermost USDW was adversely impacted as a result of the design or implementation of the Collier-Hogan 20-3H well workover.
- The DMW will be located and planned in such a manner that it should be effective at determining whether adverse impacts to the lowermost USDW have occurred as a direct result of the workover at the Collier-Hogan 20-3H.
- If FDEP desires a representative sample of produced water (or flowback water) from the Collier-Hogan 20-3H, ALL recommends that the well be produced so that a representative sample can be collected.
- If DA Hughes plans to plug and abandon the Collier-Hogan 20-3H, well integrity testing prior to plugging and abandonment is recommended.
- Considering the unsuccessful re-entry attempt at the Permit 103 well, FDEP should consider testing both the upper cement plug and casing at the well and confirm the absence of cross-flow above approximately 4,200 feet bls.

1.2 Witness Qualification

J. Daniel Arthur, P.E., SPEC

Mr. Arthur is a registered professional petroleum engineer (registered in 29 states, including Florida) specializing in energy, engineering, water, and environmental/regulatory issues. He has approximately 30 years of experience, including 6-1/2 years working throughout the State of Florida on a variety of industrial, water, and environmental issues. Mr. Arthur has experience with the geology and hydrogeology in South Florida as well as drilling, stimulation, mechanical integrity, and operation of a variety of well types in the State and worldwide.

Mr. Arthur's experience has included Project Management, coordination with third parties, site inspections, and review of technical data (including drillers' files, technical reports, well integrity data, groundwater monitoring data, and hydrogeological data). While employed with the U.S. Environmental Protection Agency (U.S. EPA), Mr. Arthur performed many hundreds of site inspections of oil and gas sites, wells, and ancillary facilities, while also performing investigations of potential environmental impacts. He has also supported investigations of alleged environmental impacts by oil and gas activities in every oil and gas producing state, served as a subject matter and testifying expert, and presented findings to high-ranking government officials and top-level management of major companies.

More specific to this matter, he has experience evaluating the mechanical integrity of thousands of wells using many different types of testing and evaluation methods. He is familiar with the federal definition of USDW and how groundwater of this general category exists throughout Florida. Finally, Mr. Arthur is expert at methods used to drill, test, stimulate, fracture treat, modify, and plug oil and gas wells. This experience also includes having a detailed knowledge of industry standard practices, best practices, safety factors, and other common methods used to assure protection to human health and the environment.

2 Information Considered

A variety of documents and data provided by the FDEP have been considered in preparing this Expert Report. A listing of those files is included as **Appendix A**. Of particular note are documents prepared for Collier County Growth Management Division and for DA Hughes:

- AECOM Technical Services, Inc., "Final Summary Report on Oil and Gas Activities within Collier County," prepared for Collier County Growth Management Division (November 2014).
- HRP Associates, Inc., "Collier-Hogan 20-3H Analysis Report, Regional Geologic Model and Workover Operation Evaluation," Dan A. Hughes Company, LP, Collier-Hogan 20-3H, Collier County, Florida, prepared for Dan A. Hughes Company, L.P. (December 2014).

Also reviewed were numerous publicly available documents cited in the endnotes of this report.

On October 29, 2014, Dan Arthur and Jeff Glenn of ALL visited FDEP's offices in Tallahassee, Florida. There they were able to review publicly available well file information. They also visited the Florida Geological Survey Sample Repository, where they were able to examine cuttings from the Collier-Hogan 20-3H well and also cuttings from the nearby Permit 86 and 103 legacy wells.

On October 30, 2014, Dan Arthur, Jeff Glenn, and Ben Bockelmann of ALL and staff from the FDEP (Danielle Irwin, Levi Sciara, Jeff Brown, and Paul Attwood) conducted a site visit to observe current conditions at the DA Hughes Collier-Hogan 20-3H oil well. Upon arrival at the wellsite, Mr. Arthur and the FDEP staff were denied access to the well pad by DA Hughes' security personnel at the site. Consequently, they were only able to conduct their observations by walking the perimeter from adjacent properties. As such, the party conducting the inspection did not have the ability to observe the well cellar, tanks, and other appurtenances on the Collier-Hogan 20-3H well pad.

The above summarizes the full extent of information available for review and which formed the basis for the discussion presented herein.

3 Purpose and Objectives

ALL was retained by FDEP to review information and offer an expert opinion concerning the Collier-Hogan 20-3H oil well and the workover procedure performed on it from December 30, 2013, to January 1, 2014. The overall purpose of this effort is to evaluate whether the workover procedure was designed <u>and</u> carried out in such a way that it was not likely to result in violations of applicable groundwater quality standards in the freshwater aquifers present at the wellsite.

In order to complete this overall purpose, ALL has addressed several specific objectives or focus areas of research concerning the Collier-Hogan 20-3H oil well. We inspected the well site from the surrounding properties as well as the surrounding area to evaluate if the well pad and well were constructed and maintained to industry practices. Also, relying on the sources noted herein (see Information Considered discussion above) we reviewed: 1) the available information on the workover procedure performed on the Collier-Hogan 20-3H well; 2) the available information on the mechanical integrity of the Collier-Hogan 20-3H well; 3) the geology and hydrogeology of the area with a specific focus on Collier, Hendry, and Lee Counties; 4) the available groundwater monitoring data from existing monitoring wells at the site to determine if fluids injected during the workover procedure resulted in adverse impacts to freshwater aquifers such that any applicable groundwater standards have been violated; and 5) the nearby legacy oil wells (Permit 86 and Permit 103) in respect to whether they are properly plugged and abandoned and if either well presents a potential threat to freshwater aquifers in light of the workover procedure performed on the Collier-Hogan 20-3H.

To date, our review and evaluation has been limited to the above items and activities. In addition, ALL, under contract to the FDEP, is currently involved in the site construction and associated drilling of a deep monitoring well adjacent to the Collier-Hogan 20-3H well pad. This deep monitoring well will be sampled to directly evaluate water quality at the base of the freshwater aquifer section (i.e., at the base of the USDW as defined by total dissolved solids content equal to or less than 10,000 parts per million [ppm]). This is being performed as part of ALL's ongoing work for the FDEP.

4 Background

In November 2012, DA Hughes submitted a permit application to drill the Collier-Hogan 20-3H oil well. The permit was subsequently issued by FDEP in December 2012 (see **Figure 1**).[2] The vertical pilot hole was drilled in the first half of 2013.[3] On November 11, 2013, DA Hughes submitted a stimulation recommendation prepared by Halliburton, and then withdrew the recommendation on December 12, 2013.[4] A second stimulation recommendation, prepared by Baker Hughes, was submitted to FDEP by DA Hughes on December 23, 2013. This workover procedure was scheduled to begin on December 28 or 29, 2013, but at FDEP's request DA Hughes postponed the procedure until December 30 to provide FDEP additional time to review and respond to the proposal.[5] DA Hughes started the workover procedure on December 30, 2013. FDEP issued a Cease and Desist Order for the workover procedure on December 31, 2013, but the procedure continued until approximately 4:29 pm of the following afternoon. On April 8, 2014, DA Hughes and FDEP entered into a Consent Order (see **Figure 1**).[6] DA Hughes retained HRP Associates, Inc., (HRP) to evaluate potential impacts resulting from the workover procedure. HRP's summary report was submitted to FDEP in December 2014.

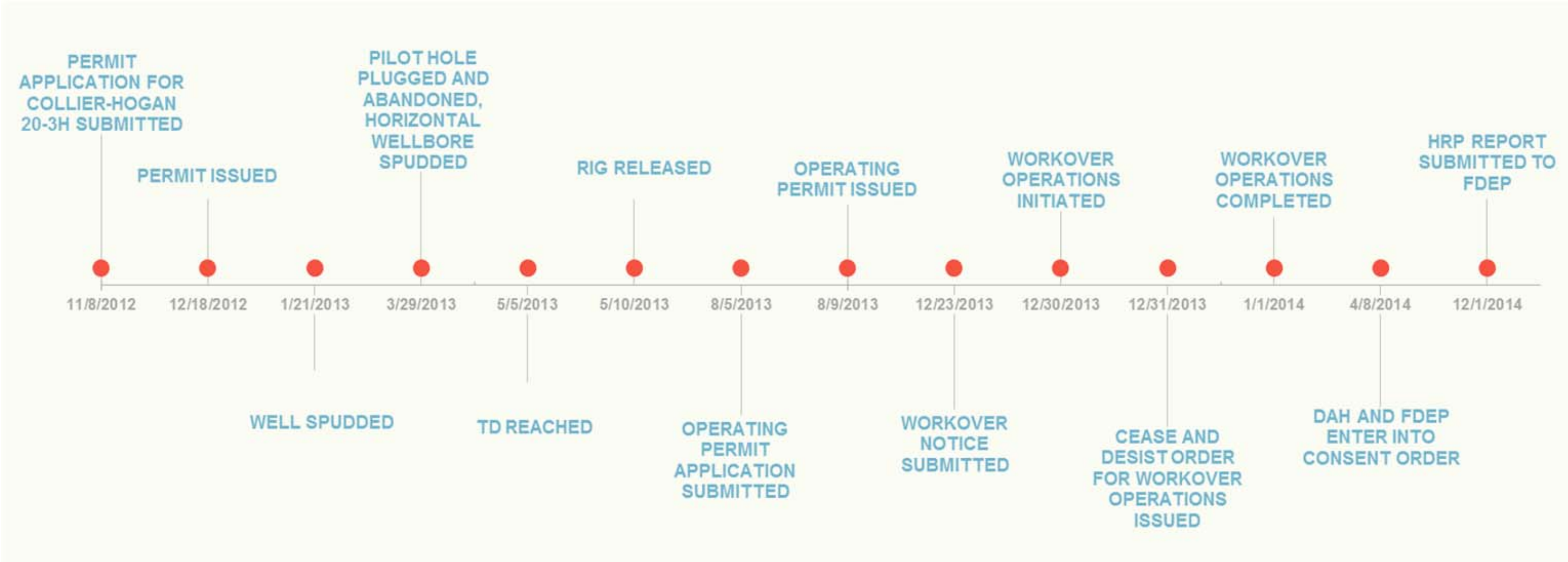

Figure 1: Collier-Hogan 20-3H Timeline of Milestone Events

Sources:

“1349 DP DP FAO 2012.pdf,” via FTP (December 18, 2012).
“Form 16. P&A Pilot Hole, Collier Hogan 20-3H.pdf,” via FTP (November, 5, 2013).
Dan A. Hughes, L.P. Daily Well Status Report, entry date March 29, 2013.
Dan A. Hughes, L.P. Daily Well Status Report, entry date May 5, 2013.
Dan A. Hughes, L.P. Daily Well Status Report, entry date May 10, 2013.
“OP FAO 2013.pdf,” via FTP (August 9, 2013)
“1349H_CO.pdf,” via FTP (April 8, 2014).

5 Technical Evaluation

5.1 File Review

ALL conducted an extensive file review of all documents and other information provided by FDEP related to the drilling, well construction, cementing, completion, and workover of the Collier-Hogan 20-3H oil well. This review included, but is not limited to, various FDEP inspection records, daily drilling reports, e-mails, geophysical logs, photographs, consultant reports, cementing records, permits, plugging reports, well stimulation plans and data, and monitoring well data. To thoroughly examine whether or not the Collier-Hogan 20-3H well workover was performed as proposed and ultimately to evaluate the data to see if the workover operations could have potentially lead to adverse impacts on USDWs, ALL reviewed and analyzed:

- Well pad construction;
- Drilling, setting, and cementing of the surface casing;
- Drilling, setting, and cementing of the intermediate casing;
- Drilling of the vertical pilot borehole and plug back procedures;
- All geophysical logging performed on the oil well;
- Drilling of the horizontal lateral section and cementing of the 7-inch casing string;
- Installation of the 4-1/2-inch production casing and initial completion work;
- Well workover and stimulation; and
- Plugging and abandonment of the Permit 86 and 103 legacy wells.

A review and evaluation of this data revealed the following issues of particular significance:

- Surface spills and releases;
- Lost circulation zones;
- Surface casing set depth; and
- Surface casing cementing records, remedial cementing operations, and cement bond log interpretation.
- Stimulation pressures vs. casing test pressures.

5.1.1 HRP Associates, Inc., Report

HRP prepared a report (dated December 2014) evaluating the Collier-Hogan 20-3H for DA Hughes.[7] This report discusses:

- Geologic and hydrogeologic overview;
- Receptor survey;
- Underground injection wells;
- Collier-Hogan 20-3H activity analysis;
- Groundwater quality evaluation;
- Evaluation and discussion;
- Conclusion;

- References; and
- Appendices, which included: Consent Order, FDEP Cease and Desist Order, published geologic information, Collier-Hogan 20-3H data, and FDEP correspondence logs.

This report provided ALL with some data which was previously unavailable. Data of particular relevance was the inclusion of service company reports and DA Hughes documents that provided insight to the original proposed workover plan and what procedures were actually performed during workover operations. Specific well post-stimulation data obtained from this report included:

- Formation breakdown, treating, and shut-in pressures;
- Volume of fluids, chemicals, and sand used in the stimulation;
- Number of stimulation stages and treatment charts; and
- Workover narrative and treatment summary.

5.1.2 AECOM Technical Services, Inc.

AECOM Technical Services, Inc., (AECOM) prepared a report for Collier County on the potential environmental impacts of oil and gas activity within the county and how that activity may affect groundwater resources.[8] The report discusses:

- Oil production in Collier County, including the various methods used to construct oil wells;
- Regulations related to oil and gas production in Florida; and
- Potential impacts of oil and gas production and recommended actions.

The report concludes with a series of recommendations for changes in Florida's oil and gas statutes and regulations to better protect groundwater.

The report reviews the various technologies used to produce oil in Florida, including vertical and horizontal wells, hydraulic fracturing, acid stimulation, and acid fracturing, with a focus on risks to groundwater. It reviews the geology of the South Florida Basin and summarizes the groundwater resources of Collier County. AECOM also presents a brief overview of Federal and state regulations related to oil and gas development.

The report addresses a series of six questions posed by Collier County, related to various types of risks posed by oil and gas activities to groundwater and public water supplies. The responses to these questions include discussion of risks posed by injection wells, plugged and abandoned wells, waste disposal, and surface spills. The discussion reviews possible fluid migration pathways from the Sunniland Trend to groundwater aquifers that could serve as a potential future water supply.

AECOM reports that it had insufficient information to determine whether the Collier-Hogan 20-3H well was hydraulically fractured. In the absence of this information, the report lists a series of general risks associated with hydraulic fracturing and acid fracturing.

5.2 Regulatory Framework

FDEP's oil and gas regulations are found at Chapters 62C-25 to 62C-30 of the Florida Administrative Code (F.A.C.). These chapters cover permitting, bonds, well spacing, drilling/well construction, production, injection, workovers, and abandonment. Chapters 62C-25 and -26 require that anyone conducting geophysical surveys, or drilling or operating an oil and gas well first obtain a permit from FDEP and post bonds for specified amounts. Chapter 62C-27 contains the regulations for drilling a well, including casing and cementing requirements, blowout preventer (BOP), and drilling fluids. There are also requirements for reserve pits, mud tanks, and dikes to contain spills and rain water.

Dikes must be constructed around each well site of sufficient size to prevent rain water from inundating the pad and to contain any spills on the site. In areas where potential spillage, flooding or drainage problems exist, the dikes must remain in place until the well is permanently abandoned.

The regulations in 62C-27 contain the requirements for casing and cementing a well. Minimum depths are specified for surface casing, depending on the depth of the well. That casing is to be set below the deepest USDW and cemented to the surface. The rules address the setting and cementing of intermediate and production casing as well. Cement for the production casing must extend a minimum of 1,500 feet above the uppermost producible zone. Well construction must also be done in accordance with "generally accepted industry standards." Each casing string must be pressure tested, using minimum surface test pressures specified in 62C-27.005(4).

All operators must submit a Spill Prevention and Clean Up Plan under 62C-28.004(2). This plan is "designed to prevent spills of crude oil and associated fluids and to expeditiously remove these fluids from the environment should a spill occur." The plan must identify each potential spill source, describe protective measures taken to avoid spills, and identify the location of equipment to be used in an emergency as well as the actions to be taken to clean up any spills. DA Hughes appears to have satisfied this requirement by submitting a Spill Prevention Control and Countermeasures Plan effective June 12, 2014.

Blowout Prevention (BOP) equipment must be installed before drilling below the surface casing shoe. The regulations contain requirements for the type of BOP equipment to be used, depending on the type of well. At a minimum, BOP equipment must be pressure tested weekly and after each additional string of casing is set.

In order to obtain a drilling permit from FDEP for the Collier-Hogan 20-3H well, DA Hughes was required to follow the well construction procedures described in these regulations. Along with their permit application, the company submitted a location plat, site construction plans, and a casing and cementing program. These are required under Chapter 62C-26.003. They also submitted an H2S/Emergency Contingency Plan, Drilling Fluids Program, and a Directional Drilling Program.

Each operator must notify the FDEP prior to commencing a workover operation, as required under Chapter 62C-29.006(1). DA Hughes provided notice on December 23, 2013, along with a detailed completion procedure dated December 22, 2013.

5.3 Collier-Hogan 20-3H Site Inspection

On October 30, 2014, ALL, in conjunction with FDEP, performed an initial site inspection of the Collier-Hogan 20-3H well site. While at the site, ALL and FDEP staff visually surveyed the proposed site for a DMW to be installed by FDEP contractors. Persons present at the site performing and assisting in the inspections were Dan Arthur (ALL), Ben Bockelmann (ALL), Jeff Glenn (ALL), Danielle Irwin (FDEP), Levi Sciara (FDEP), Jeff Brown (FDEP), and Paul Attwood (FDEP). Notes were taken during the Collier-Hogan 20-3H well pad inspection and subsequent inspection and staking of the DMW site. Photographs taken at the inspection can be found in **Appendix B**. The following log is transcribed from notes taken by ALL staff.

<table>
<tr><th>Time</th><th>Observations</th></tr>
<tr><td colspan="2">Site Inspection Log: Collier Hogan Well Pad with staking and observational survey of adjacent well pad – preconstruction and assessment prep.</td></tr>
<tr><td>9:15 am</td><td>Sign in at check point (Personnel and communications noted above)</td></tr>
<tr><td>9:25 am</td><td>Conversation with Paul Attwood (FDEP field inspector) while waiting for site authorization.
• Dan Arthur inquired as to Paul Atwood’s observations/knowledge of activities during drilling and completion of the Collier-Hogan 20-3H well. Paul Atwood indicated the following:
o Lost circulation zone encountered at approximately 1,600 feet.
o Surface casing stuck at 1,715 feet.
o In an effort to confirm that the Surface Casing was set to an adequate depth, DA Hughes ran a resistivity log to estimate if the Casing was set through the lowermost USDW. FDEP reviewed the log and approved the setting depth.</td></tr>
<tr><td>9:35 am</td><td>(At check point)
Johnathan Blake (security supervisor) indicated no “on pad” access would be granted today (October 30, 2014).</td></tr>
<tr><td colspan="2">Start of Collier Hogan Notes:</td></tr>
<tr><td>9:40 am</td><td>(South side of Collier Hogan pad)
Safety Meeting led by Dan Arthur</td></tr>
<tr><td>9:45 am</td><td>(SE corner of pad, Photos 1-8)
Made remote observations starting from Southeast corner of pad proceeding North (east side)
• Paul Attwood noted monitoring wells installed on pad corners (approximately 13 feet deep) and stated that the pad was constructed of impermeable lime rock with a liner on the pad during drilling and that company men’s trailers were located on the east side of the pad during drilling.</td></tr>
</table>

Time	Observations
9:55-10:05 am	(East side of pad) Stopped at north end to make note of secondary containment observations in tankage area. • Dan Arthur noted that work appears to be active on building berms for storage tanks (as indicated by lifting equipment in the area, disturbed areas around the berms and liner exposure and rippling at the edges). A comment was made about the possibility of the piping and disturbances creating penetrations of the liner. (Unable to verify or disprove during this visit.) • Dan Arthur observed plastic underlayment of containment area, plastic also drapes through berm but appears to be laid flat instead of grading up and over berm incline and decline. • Danielle Irwin showed Dan Arthur some photos of the prior tank battery configuration (no note of date or specifics from photos per note taker).
10:10 am	(North side of pad) Dan Arthur and Levi Sciara looked through binoculars observing the following: • Wellhead rod connector assembly not connected to pumping unit harness (Weatherford Rotoflex pumping unit as seen in several photos – center of location). The observations and photos were taken from approximately 175 feet away (halfway across the 350-foot pad from the center of the north side). • Well head pressure gauges were present and visible (annular and tubing pressures were noted to be 0 psig). • There appeared to be no evidence of distressed vegetation outside of the berms (as observed with specific comments by Dan Arthur and Paul Attwood).
10:20 am	(North side of pad near west corner and northwest corner) • Observed and photographed filled breach of berm (Photo: Dan Arthur with breach to his right in background (north side near west corner). • Photo of recent disturbance (mud with tire tracks – likely from monitoring well rig. (northwest corner)
10:25 am	(West side of pad –center) • Dan Arthur noted that the fiberglass tanks appeared to be freshly painted. • Danielle Irwin validated that she had observed the tanks in a prior unpainted state. • Levi Sciara noted that tanks/facilities require a Professional Engineer's (PE's) seal and that fiberglass is not a desired material due to degradation when exposed to sunlight). • Again, Dan Arthur noted the observation of holes/tears in plastic on battery from this vantage point.

Time	Observations
10:35 am	(Southwest corner of pad) • There were seven (7) "frac tanks" located inside the berms and one (1) outside at this corner. • A chemical tote and two or three pallets with seven (7) steel barrels were stored at this corner. • No secondary containment for the tote or barrels was observed.
10:40 am	(End of Collier Hogan pad observations)
End of Collier Hogan Notes	
	Camera battery replaced and personnel proceeded to van for water break and to make up stakes for new pad demarcation.
Brief Description of staking and inspection of DMW well pad:	
11:00 am through noon	(DMW site staking and visual survey) Set stakes at corners, split up into two groups. Ben Bockelmann, Levi Sciara and Jeff Glenn staked silt fence and sock markers while Dan Arthur, Jeff Brown, Paul Attwood and Danielle Irwin made observational sweeps across the DMW pad area in a north-south orientation and at about three (3) yard spacing until the site was fully assessed. (Per comments heard by note taker Jeff Glenn, there was standing water observed for chloride testing, and Paul Atwood commented about a tire and a small piece of lumber).
END of Record	

5.4 Drilling and Well Construction

This section contains ALL's technical review of DA Hughes' drilling and completion procedures on its Collier-Hogan 20-3H (Permit 1349H) oil well. The scope of this review follows Tasks 7 through 9 of the Schedule and Task List.[9] The documents used for this section were provided by FDEP and include the following:[10]

- FDEP inspection reports,
- Daily drilling reports of the Collier-Hogan 20-3H,
- Emails,
- Reports by AECOM[11] and HRP Associates, Inc.,[12] and
- Permits and forms submitted by DA Hughes.

To determine whether the well's drilling and completion operations could have resulted in adverse impact to any USDW, ALL examined information from these documents related to:

- Drill pad construction,
- Drilling surface casing borehole,
- Setting and cementing surface casing,
- Intermediate casing 9-5/8-inch pipe,
- Drilling to core pilot vertical hole and plug back,
- Drilling horizontal lateral and cementing 7-inch casing,
- Drilling open hole lateral, and

- Installation of 4-1/2-inch casing and initial completion work.

5.4.1 Drill Pad Construction

Proper containment and clean-up of spilled materials are critical to preventing adverse impact of USDWs during site construction. A review of the records shows possible conduits for spilled material to migrate downward. DA Hughes had losses of fluids that might have traveled down one or more of the following conduits.

Figure 2: Apparent Berm Fluid Discharge Pipe with Erosional Gully

Source SD Photo folder

- The 300-foot x 300-foot pad, with berm, was built on December 20, 2013, with a partial liner. A FDEP field inspection photo shows a PVC pipe protruding from what looks to be the outside of the berm wall (see **Figure 2**). An erosional gully present under and down slope of the pipe would indicate that fluid had come out of it. Neither a Storm Water Pollution Prevention Plan (SWPPP) nor records of a discharge were found in the documents.
- FDEP inspection reports mention that the department requested that DA Hughes remove oil-stained pad material from where the rig had been working below above-ground diesel tanks and remove oily fluid around the wellhead after the rig had moved off location.
- One FDEP report mentioned that the liner had been torn. No violations were cited with regards to the spillage or material removal.[13]
- Although there is no mention in the provided material, there may have been a discharge immediately from or outside of the berm as evidenced by the presence of a yellow containment boom in that area (see **Figure 3**).
- On the drill pad, a 10-foot x 10-foot cellar was dug that had concrete poured for its bottom. A mouse hole was installed inside the cellar by driving 16-inch steel pipe to 90 feet bls. A 145-foot x 110-foot 40-mil poly liner was laid around the cellar for the rig. Polyethylene

Figure 3: FDEP Photo of Yellow Boom

Source SD Photo folder

interlocking drilling mats from another well (there are no records of their condition, or if they were cleaned) were installed on top of the liner.[14]

- A 24-inch outside diameter (O.D.) steel conductor was driven to 196.5 feet on January 8, 2013.[15] Then a 10-foot diameter corrugated metal pipe was put in the earthen-walled cellar. There was no mention in the records of what is between the earthen walls of the cellar and the corrugated metal pipe.

Observations

Spilled or poorly contained fluids (e.g., chemicals, additives) could have traveled down the outside of the un-cemented conductor, the mouse hole, the corrugated metal pipe, the cellar, or unlined pad areas into shallow groundwater during construction, drilling, completing and production processes. Material was removed from the pad but not properly contained (See **Figure 4**).

5.4.2 Drilling Surface Casing Hole

DA Hughes had difficulties drilling the surface casing borehole. Those difficulties could potentially have compromised external integrity of the surface pipe.

- When the 17-1/2-inch hole was drilled to a total depth (TD) of 1,908 feet, DA Hughes lost tools in the borehole at 1,440 feet. They then had to fish without full recovery. This junk was pushed to the bottom of the surface casing hole. As DA Hughes' daily drilling reports started at 1,440 feet, FDEP inspection records for drilling activity were relied upon to this point.[16]
- At a depth of 1,638 feet, drilling-fluid-returns to the surface were lost and multiple lost circulation material (LCM) pills were spotted.[17]
- When tripping out of the hole from 1,791 feet, the bottom hole assembly (BHA) got stuck in the bottom of the 24-inch conductor pipe. DA Hughes noted "confirmed damage to conductor shoe." They then milled the conductor pipe and leveled the drilling rig. FDEP noted damage to the drill bit and stabilizers (see **Figures 5** and **6**). DA Hughes had to back ream multiple times and noted intermittent to excessive drag while drilling.[18]

Figure 4: Foreground- What Appears To Be Contaminated Rubble with Improper Containment and Coverage; Background- Barrels of Chemical with No Obvious Secondary Containment

Source: SD Photo Folder

Figure 5: FDEP Photo Indicating Damage to Stabilizer

Source SD Photo Folder

Figure 6: FDEP Photo Indicating Damage to Drill Bit

Source SD Photo Folder.

<u>*Observations*</u>

Lost circulation, damage to the conductor pipe, fishing, junk left in the hole, a plugged bit, damaged bit and stabilizers, and leveling the rig (which could indicate they were drilling crooked and/or that they pulled on the pipe hard during fishing and hung up inside the conductor pipe) were not the optimal conditions for setting and cementing surface casing. Conditions like these can cause wash-outs and/or obstructions preventing adequate external surface casing integrity.

5.4.3 Setting and Cementing Surface Casing

DA Hughes had difficulties setting and cementing the surface pipe. Those difficulties could potentially have compromised the casing's external integrity.

- DA Hughes began to run 13-3/8-inch surface casing on January 29, 2013. They had difficulty getting to the bottom (intended surface casing depth was 1,908 feet) with the surface pipe. DA Hughes pumped through casing with no returns, and then had to wash the surface casing from 1,664 feet to 1,718 feet.[19] DA Hughes noted in their drilling log that they received permission from Paul Attwood of the FDEP to proceed to cement at this depth, leaving 190 feet of open hole below the surface casing shoe.[20]
- To cement the surface pipe, DA Hughes rigged up a "Tag-in Cement Stinger" and tripped in the hole (TIH) with the 5-inch drill pipe. They then stung the pipe into the surface casing shoe.[21] DA Hughes recorded pumping a total of 995 sacks of Class A and H cement with CaCl additive,[22] while FDEP recorded a sum of 1,363 sacks (a difference of 368 sacks).[23] Neither DA Hughes, Baker Hughes cementing reports, nor FDEP recorded cement returns to the surface.
- As cement did not circulate to the surface, DA Hughes began to cement the surface-conductor casing annulus from the surface. FDEP recorded that a 1-1/4-inch tremmie pipe was run in the conductor-surface casing annulus, but does not give the depth to which the tremmie pipe was run.[24] FDEP recorded 335 sacks of cement with pea gravel

used to top-off the well.[25] DA Hughes does not mention the tremmie method; they only report that they pumped 44 yards of ready mix cement down the annulus.[26]

- DA Hughes' document "Dan A. Hughes Company Proposed Plug and Abandon Procedure" listed the setting depth of the 13-3/8-inch casing at 1,715 feet,[27] while DA Hughes' daily drilling reports has the casing set at 1,718 feet (a difference of 3 feet).[28]
- After cementing the surface pipe, DA Hughes tested the surface casing to 1,000 psi, but no time intervals were reported. FDEP mentions this test in their report, using the term "successful" in quotation marks.[29]
- FDEP wrote in the February 2, 2013, report that a USDW is above the 13-3/8-inch casing shoe and therefore is protected. In more detail, FDEP reported that a resistivity/dual induction log was run to 1,912 feet with a resistivity equal to 2.5 ohms to 3.5 ohms below 1,728 feet. FDEP's Paul Attwood went on to write, "Saltwater from Boulder zone may have migrated up to the severe lost circulation zone at 1,638' DF [Drill Floor], then contaminated the porous zones below 1,638' DF. TDS of water below 1,738' DF greater than 10,000 PPM per induction log."[30] However, review of the log shows resistivity readings above 10 ohms, questioning the above interpretation.
- Youngquist Bros. ran a CBL on February 1, 2013, from 1,711 feet to 50 feet, and a review of the CBL indicates free pipe signal and low amplitude readings that demonstrate a poor cement job. There is no mention of running the CBL under pressure.[31]

<u>*Observations*</u>

As a result of DA Hughes stinging into the shoe inside the surface pipe and pumping, it is more probable the cement would have gone down the open hole below the pipe (the path of least resistance) instead of up the backside of the surface pipe. If the cement traveled up to the lost circulation zone at 1,638 feet, the cement could have at that point gone back into the formation, but not further up the annulus. Review of the Baker Hughes cement job report reveals that no centralizers (FDEP has photos of surface casing centralizers on location) were installed on the surface casing. Tremmie-piping down and pumping cement with pea gravel from the top can lead to bridging-off conditions in the surface casing annulus and, hence, to intervals of no cement and/or poorly bonded cement. An analysis of Baker Hughes' cement job reports, which have been corrected by FDEP, reveals no circulation or no cement returns to the surface.

5.4.4 Intermediate 9-5/8-inch Casing

DA Hughes had difficulties drilling the borehole and running in the intermediate casing string. These are signs of a compromised mud program.

- DA Hughes drilled a 12-1/4-inch hole to 3,965 feet. Their daily drilling log reports lost returns on a regular basis from 2,031 feet to 3,965 feet. It also notes they pumped 10 barrels (bbls) Hi-Vis sweeps as they had torqueing problems.[32]
- When Offshore Energy's Casing crew ran casing to 3,964 feet, the pipe hit obstructions at 2,026 feet; 2,075 feet; 2,085 feet; 2,200 feet; and 2,300 feet. This required them to wash down the pipe and ream the borehole.[33]
- DA Hughes' notes in their Proposed Plug and Abandon Procedure document that places the estimated top of cement at 3,400 feet (note reads "Est TOC 3,400'"). This left an uncemented interval from 3,400 feet to 1,718 feet bls.[34]

<u>*Observations*</u>
With frequent drilling intervals of no returns and obstructions hit when running in the borehole, this suggests numerous washouts of the borehole and ALL questions whether the mud program was adequate. Improperly planned and poorly executed mud programs may lead to poor cement bonding. There is no evidence that DA Hughes ran a CBL on this casing string, or made an attempt to determine the top of cement in the annulus.

FDEP witnessed a MIT performed on the intermediate casing, using a test pressure of 1,002 psi for 30 minutes, with an approximately 1% loss.[35] The MIT pressure varied only three pounds over the last 25 minutes of the 30-minute test, which ALL interprets as stabilizing. The intermediate casing appears to have had internal integrity at this point. However, this and other strings may have received internal and external damage from the many fishing jobs and junk that traveled up and down the hole later, compromising internal casing integrity.

According to daily drilling reports, DA Hughes cemented on February 12, 2013, with 809 sacks Poz mix cement and Class H cement by pumping down the 9-5/8-inch casing with a wiper plug.[36] However, FDEP records a total of 630 sacks of cement (a difference of 179 sacks from DA Hughes). Baker Hughes' job reports are available and have been corrected by FDEP.

5.4.5 Drilling to Core Vertical Pilot Hole and Plugging Back

DA Hughes lost returns while drilling, fished core sections and BHA, and had to cement drill pipe in the hole, all of which called into question their mud program and borehole conditions:

- DA Hughes drilled an 8-1/2-inch hole to 11,704 feet, losing partial returns from 6,057 feet to 6,598 feet, and pumped lost circulation material while drilling. They drilled to 7,302 feet, but then lost 276.89 feet of BHA in hole at 7,025 feet. DA Hughes fished and recovered junk in hole, after making numerous trips in holes with tools. At this point the well began flowing.[37]
- DA Hughes regained returns and drilled to 9,842 feet. The rig cored from 11,704 to 11,736 feet, 11,870 to 11,937 feet, and 13,223 to 13,265 feet, recovering incomplete intervals (core barrels malfunctioned). DA Hughes made multiple attempts to recover lost core sections.[38]
- DA Hughes tried to plug back the bottom of the borehole (TD 13,370 feet) with cement by pumping 865 sacks of cement through the drill pipe.[39] The pipe then became stuck at 11,365 feet. They tried to back off, but were unsuccessful, so they perforated the drill pipe leaving the top of drill pipe fish at 9,310 feet.[40] The total length of the fish left in hole was 2,055 feet.

<u>*Observation*</u>
With frequent intervals of no drilling mud returns, tools being stuck and pipe stuck and left in the borehole, ALL questions the mud program and its condition to ultimately provide a foundation for adequate cementing.

At this point, the downhole deviation surveys do not give concern for a crooked hole in this section of the wellbore (recorded deviation of 0.2 degree surveyed at 9,842 feet; 0.2 degree at 10,789 feet; and 0.6 degree and at 11,453 feet).[41]

With regards to the plugging back of the vertical pilot hole below the horizontal kick-off point, although there was pipe left in the hole, the 300 sacks of cement pumped on top of fish brought the top of the cement to 8,471 feet providing an adequate plug.[42,43]

5.4.6 Drilling Horizontal Lateral and Cementing 7-inch Casing

DA Hughes had junk in the borehole and tight-spot problems similar to what they experienced in the vertical pilot hole operations:

- While drilling the horizontal lateral on April 2, 2013, DA Hughes recorded "Completed drop back to vertical" and "Steering mode has problems," with no further explanation.
- When DA Hughes tried to trip in with 7-inch production pipe, they hit an obstruction or tight spot at 5,352 feet. They tripped back in reaming from 4,004 feet to 7,515 feet and various intervals to 12,437 feet using 8-1/2-inch mill tooth.[44]
- FDEP noted that DA Hughes had to use jars to become unstuck at 11,750 feet and that a metal fin was missing on the reamer.[45] DA Hughes indicated that they milled with junk baskets and magnets from 12,442 feet to 12,445 feet measured depth (MD).[46] They then placed a 70-bbl graphite pill on bottom.

<u>*Observations*</u>
With the amount of reaming and associated tripping and junk at or near the collar of the 7-inch casing, it brings into doubt the mud program and gauge of the lateral to this point or how well the production pipe would be centered in the borehole. Pipe not centered can lead to poor cement flow, poor placement, and poor bonding.

DA Hughes set 7-inch casing to 12,440 feet MD (5 feet off bottom), conditioned with mud, and then cemented with 1,010 sacks of class H cement. The pumped plug held at 500 psi over circulation pressure (for 5 minutes) after initial loss of 1.25 bbls. They noted 1,522 feet of cement inside the 7-inch casing.[47] This is an excessive amount of cement inside the 7-inch casing after pumping a plug. With no cement bond log available, there is no way of knowing the top of the cement or bond condition on the outside of the 7-inch casing. ALL questions this string's external integrity.

A MIT was performed on the 7-inch casing and witnessed by Mark Robert Jones, drilling consultant for DA Hughes on April 21, 2013. The beginning test pressure was 1,015 psi, which increased to 1,031 psi in 30 minutes.[48] The pressures climbed (i.e., didn't stabilize) throughout the test period. The rising pressure could indicate that cement was moving back into the pipe, or that there was a leak in the casing caused by formation pressure. This MIT does not give assurance the internal pipe integrity was adequate.

5.4.7 Drilling Open Hole Lateral

DA Hughes began drilling the open borehole lateral on April 24, 2013, by milling with junk baskets and magnets. There is no explanation of what was lost in the hole or if all the fish was recovered from 12,442 feet to 12,455 feet MD. They finished the remainder of the hole drilling with a 6-1/8-inch bit.[49] On May 5, 2013, they reached 16,215 feet measured total depth (MTD). The true vertical depth (TVD) was 11,948 feet. The borehole was logged with Baker STARTRAK from 12,452 feet to 15,896 feet MD. On May 9, 2013, DA Hughes pumped a bleach pill and displaced hole with KCL.[50] The open hole was logged from 13,819 feet to 16,215 feet MTD.

The drilling rig was released at 6:00 pm, May 10, 2013, concluding the drilling phase.[51]

Observations
With numerous fishing jobs and possible junk left in the hole (the record is not complete as to what was recovered) it is very possible the open hole packers on the 4-1/2-inch production casing could have been damaged tripping in the hole. Damage to the packers could have prevented them from enlarging properly or caused them not to seal during placement. Packers that did not properly seal could be a conduit of fluid movement at the proposed approximate 9,000 psi bottom-hole treatment pressure. This, coupled with poor cement jobs on the production, intermediate and surface casings, could have provided conduits to USDWs.

On May 10, 2013, DA Hughes entered "Rigging down" and "Cleaning Mud Tanks" on their Daily Well Status Report. There was no mention of how the tanks were cleaned or what happened to the waste. If cleaning waste was not properly handled and disposed, the waste could have traveled downward where there was no liner, the outside of the mouse hole, outside the conductor pipe, or out what appears to be a pad discharge pipe any of which could have impacted the shallow USDW.

5.4.8 Installation of 4-1/2-inch Production Casing and Initial Completion Work

There were no available records from contractors that performed this work giving firsthand accounts of how the 4-1/2-inch production casing was installed or the initial completion work was performed. ALL relied on after-the-fact information from DA Hughes vendors and FDEP. **Figure 7** is a current wellbore schematic by DA Hughes:[52]

- According to a Halliburton well stimulation proposal dated November 11, 2013, the 4-1/2-inch casing was set on inflated packers in the open-hole horizontal lateral. The 4-1/2-inch production casing (13.5#, P-110 with a burst of 12,410 pounds and collapse of 10,680 pounds) was set to a MD of 16,215 feet on September 29, 2013.
- A diagram within Halliburton's proposal shows seven packers set from 15,701 feet to 12,644 feet. The Halliburton proposal also lists four stages of perforations from a MTD of 16,103 feet to 15,800 feet with roughly 100 feet spacing. The well received an unspecified acid treatment.[53]
- C.S. Forbe's completion rig was on the well July 12, 2013, as noted on an FDEP inspection report. The well was making 16 bbls to 27 bbls of 23 to 24 degree oil and a trace of 1,500 ppm chloride water per day (FDEP does not cite its source for the produced water values).[54] There was no notation of the 4-1/2-inch production casing, or the methodology of completion rig (i.e., swabbing into pit or tank, etc.).

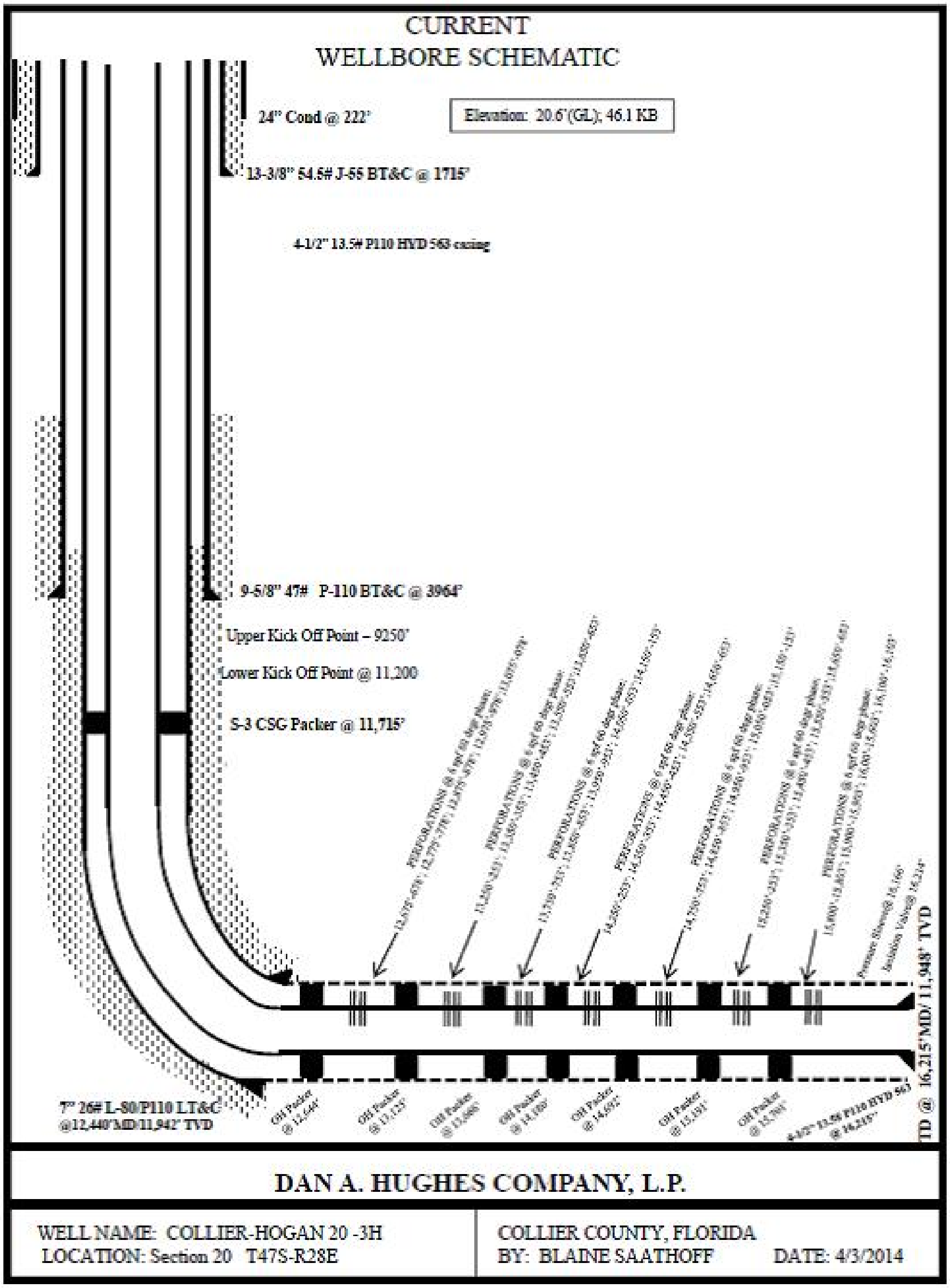

Figure 7: Current Wellbore Schematic of the Collier-Hogan 20-3H Oil Well

Source: Baker Hughes, Post-Stimulation Report, Dan A Hughes Collier-Hogan 20-3H (Stages 1-7), Lower Sunniland Formation, Collier County, Florida, API # 09-021-76040-0000, in HRP Associates, Inc., Collier-Hogan 20-3H Analysis Report, Regional Geologic Model and Workover Operation Evaluation, Dan A. Hughes Company, LP, Collier-Hogan 20-3H, Collier County, Florida, Appendix E-3, prepared for Dan A. Hughes Company, L.P., prepared by HRP Associates, Inc. (December 2014).

<u>*Observations*</u>
A review of the logs of contractors who performed the installation and initial completion work would enable ALL to offer an opinion on the internal and external integrity of the liner and packers. Without adequate records it cannot be determined how waste fluids were handled or contained to prevent adverse impact to the USDW.

The HRP report (December 2014) includes a memorandum from "TH" data from November 25, 2014. The memorandum is brief and was written considerably later than well drilling activities on the Collier-Hogan 20-3H well, but it does provide some insights on Mechanical Integrity. In the memorandum, the author notes that each of the casing strings was pressure tested to roughly 1,000 psig prior to drilling out the cement plug at the casing shoe. This testing serves to confirm that the casing system likely had "Internal" Mechanical Integrity. The memorandum does not specify a duration for the test, pressure fluctuations, how the pressure was measured, or whether there was an actual record of the pressure test. Considering the fact that the memorandum was prepared approximately a year after these various tests, it is not possible to fully affirm this conclusion.

5.5 Workover Procedure

5.5.1 Collier-Hogan 20-3H Workover Proposals and Procedures

On September 16, 2013, DA Hughes received an acidizing proposal from Baker Hughes for the Collier-Hogan 20-3H oil well.[55] This proposal was an acid treatment schedule through existing perforations that involved a cumulative total of 1,295.5 bbls of slurry/clean fluid in 17 stages at a maximum surface treating pressure of 6,270 psi. There was no mention of proppant or sand to be used during this treatment schedule. A completion procedure dated September 16, 2013, from Jeff Ilseng, Operations Manager for DA Hughes, provides details of the procedure and makes the following statement: "If well does not produce after swabbing, evaluate a sand stimulation into perfs."[56] According to a completion procedure submitted to FDEP which is dated November 11, 2013, the Collier-Hogan 20-3H oil well was treated with acid on September 29, 2013.[57] An e-mail exchange between Joyce Smith with DA Hughes and Timothy M. Riley, legal representative to DA Hughes, indicated that "(t)he stage 1 perfs were added, and acidized with a small scale acid stimulation job. The results were fairly poor, but encouraging (low oil volume on swab tests after acidizing) where it was determined that a larger scale acid stimulation was to be employed covering the entire lateral. We proposed to re-stimulate this stage and add an additional (6) stages over the length of the lateral."[58] ALL, however, could not locate any service company records indicating what acid treatments were performed on the well.

On November 11, 2013, DA Hughes submitted a Workover Notification to FDEP regarding a completion procedure to be performed on the Collier-Hogan 20-3H oil well. FDEP received this completion procedure document on November 20, 2013. This document was entitled "Borate X-Link Stimulation Recommendation" and was prepared for DA Hughes on October 21, 2013, by Halliburton.[59] This stimulation recommendation proposed 13 stages with the use of a total of 88,170 gallons of 2% KCL water, 3,000 gallons of 15% hydrochloric acid (HCL), and 49,500 pounds of sand as a proppant. Halliburton's Fracpro 2012 Hydraulic Fracturing Analysis predicted total fracture height of 276 feet (fracture top at 11,784 feet), propped fracture length of

335 feet, 15 bpm pumping rate, and reservoir pressure of 5,208 psi. On November 25, 2013, Levi Sciara, with FDEP Oil and Gas Program, sent a letter to Jeff Ilseng with DA Hughes requesting additional information on the proposed well stimulation.[60] DA Hughes responded to those questions verbally on December 2, 2013. On December 12, 2013, Timothy M. Riley, a legal representative of DA Hughes, sent an e-mail to Ed Garrett and Levi Sciara of FDEP requesting withdrawal of the Halliburton completion procedure for the Collier-Hogan 20-3H oil well.[61]

On December 23, 2013, Timothy M. Riley, legal representative of DA Hughes, contacted FDEP and provided them with documents for another proposed completion procedure, this time designed by Baker Hughes for the Collier-Hogan 20-3H oil well.[62] This Baker Hughes proposed well treatment included 90,909 gallons of water, at least 49,500 pounds of sand per stage, HCL acid, gelling agents and breakers, biocides, non-emulsifiers, cross-link modifiers, pH control buffers, and paraffin control products. Seven stimulation stages were to be performed. The treatment loads were to be delivered at a rate of 1 to 15 bpm, with an estimated pump time of 2 hours and 39 minutes. Maximum surface treating pressure was to be 5,093 psi with a stimulation gradient of 0.80 psi/ft and bottom hole stimulation pressure at 9,427 psi. On December 27, 2013, Timothy M. Riley, the legal representative for DA Hughes, e-mailed FDEP personnel and informed them that even though the original Baker Hughes workover operation was planned to commence on December 28th or 29th, no activities would occur prior to December 30, 2013.[63]

5.5.2 Collier-Hogan 20-3H Workover

Baker Hughes commenced a seven-stage well stimulation on the Collier-Hogan 20-3H oil well at 2:02 pm on December 30, 2013, and ended the stimulation operation at 4:29 pm on January 1, 2014.[64] Formation breakdown pressures for the seven stages approached approximately 9,000 psi. Average treating pressures varied from 8,287 to 8,397 psi and average pumping rates were from 17.3 to 28.2 bpm. Instantaneous shut-in pressures (ISIP) for the seven stages ranged from 7,425 to 7,955 psi. Annular pressure readings were reported as zero on all seven stages of the Baker Hughes stimulation treatment reports. The total stimulation job pumped approximately 662,298 gallons (15,769 bbls) of fracturing fluids and 637,399 pounds of sand proppant for a total slurry volume of 691,068 gallons or 16,454 bbls (see **Table 1**).[65] Given that the pumping pressure exceeded the formation fracture gradient, that the fluid used, including additives, resembles hydraulic fracturing fluid, and that proppant was emplaced in the fractures, we conclude that this workover procedure was a hydraulic fracturing job. In ALL's experience, the amount of fluid and proppant used make this a hydraulic fracture stimulation job. A summation of fracturing fluid additives indicates that approximately 2.2% volume of the total fluid (i.e., "clean volume") was comprised of chemical additives (see **Table 1**).

Table 1: Collier-Hogan 20-3H Stimulation Fluid Volume					
STAGE	**BREAKDOWN PRESSURE (psi)**	**SLURRY VOLUME (bbls)**	**CLEAN VOLUME (bbls)**	**PROPPANT (lbs)**	**ADDITIVES (bbls)**
Stage 1	7,802	2,320	2,256	59,264	51.8
Stage 2	8,006	1,749	1,702	44,022	43.1
Stage 3	8,770	2,521	2,411	101,832	51.6
Stage 4	8,629	2,114	2,031	76,955	46.8
Stage 5	8,509	2,391	2,283	100,625	47.8
Stage 6	7,975	2,887	2,738	138,982	56.6
Stage 7	8,641	2,472	2,348	115,719	52.1
TOTAL		16,454	15,769	637,399	349.9
					2.2 % vol

Source: Baker Hughes, Post-Stimulation Report, Dan A Hughes Collier-Hogan 20-3H (Stages 1-7), Lower Sunniland Formation, Collier County, Florida, API # 09-021-76040-0000, in HRP Associates, Inc., Collier-Hogan 20-3H Analysis Report, Regional Geologic Model and Workover Operation Evaluation, Dan A. Hughes Company, LP, Collier-Hogan 20-3H, Collier County, Florida, Appendix E-3, prepared for Dan A. Hughes Company, L.P., prepared by HRP Associates, Inc. (December 2014).

<u>Observations</u>

DA Hughes commissioned HRP to prepare a report analyzing the workover at the Collier-Hogan 20-3H oil well.[66] The HRP report includes Baker Hughes' results of modeling using their MFrac 3D Simulator. The subject model does not directly match either the proposal or the actual stimulation, but it does provide insights into the stimulation job. Page 2 of the simulation report estimates the maximum surface injection pressure to be 4,133.2 psi and the maximum BHTP at 8,703.3 psi. Maximum fracture height was also estimated at 14.365 feet above the horizontal section of the well (true vertical depth estimated at 11,927 feet bls); total fracture height was estimated at 73.228 feet (14.365 feet above the lateral and 58.863 feet below the lateral). However, the simulation (i.e., modeling using the MFrac 3D Simulator) was performed using volumes for fluids and proppants that were less than what was used in the actual workover operations (i.e., modeling was not performed to match actual events).[67]

The actual workover on the Collier-Hogan 20-3H well was conducted from December 30, 2013, through January 1, 2014, as specified in the Baker Hughes Post-Stimulation Report.[68] The Post-Stimulation Report is a record of the actual workover procedure and is not a plan or model. As such, this report includes data reflective of what was planned for the stimulation and how the stimulation was ultimately performed. Based on this record, there are several items that are relevant to the issue of assessing the workover procedure for purposes of this report. These include, but may not be limited to, the following:

- **Stages**: The well was stimulated using a multi-stage treatment procedure that included a total of seven (7) separate stages in the horizontal portion of the wellbore.

- **Fluid Volumes**: The Baker Hughes report also notes that a total slurry volume of 691,068 gallons (16,454 bbls) were used for the workover, including combined fluid totals for all seven (7) stages.
- **Formation Breakdown**: Formation breakdown pressures approached approximately 9,000 psi with average treating rates ranging up to approximately 28.2 bpm. Graphical recordings of pressures and other parameters are included in the report for each stage and clearly show (and annotate) a breakdown pressure during Stage 1 of 7,802 psi. Further, the signature of the pressure graph confirms this conclusion. With this information, it can be concluded with confidence that the workover on the Collier-Hogan 20-3H well involved hydraulic fracturing of the formation on each of the seven stages. In ALL's experience, considering the volume of fluids used in all stages, the subject workover would be considered a multi-stage HVHF stimulation job.
- **Irregularities**: Review of the various data and plots from the Post-Stimulation Report show common results for HVHF jobs. Upon assessing the subject data in detail, no specific irregularities or data that would indicate a concern were noted. Maximum BHTPs were noted to approach approximately 9,000 psi, but the scale of the charts made actual maximums difficult to assess. There was no indication that any of the 7 treatment stages circulated up the backside of the 7-inch casing to 4-1/2-inch casing annular space during the well stimulation process, which would be indicative of external mechanical integrity failure. This is further supported by the zero pressure recordings on this annular space during all seven stimulation stages. Data records do not appear to suggest an abnormal formation reaction, well integrity loss, or other potentially concerning issue.

5.6 Area Geology

5.6.1 Lithostratigraphy of the Collier-Hogan Area

The Collier County area of southern Florida lies within the South Florida Basin.[69] This basin is floored by igneous basement rock of Jurassic age and filled with approximately 17,000 feet of sedimentary strata ranging in age from Jurassic to Holocene (see **Figure 8**). The basement is overlain by approximately 7,000 to 9,000 feet of Upper Jurassic- through Lower Cretaceous-aged limestones and dolomites with some evaporites and clastics.[70] Oil- and gas-bearing strata are present at various intervals in this sequence, but only the Sunniland Formation has been economically produced in the South Florida Basin.[71] The base of the Lower Cretaceous-aged Sunniland Formation was targeted by the DA Hughes Collier-Hogan 20-3H oil well.

The Sunniland Formation is approximately 200 to 300 feet thick and the top occurs at a depth of approximately 11,200 to 11,600 feet bls.[72,73] The Sunniland Formation is divided into reservoir units denoted D, C, B and A (from base to top). Each of these units are 40 to 50 feet thick and comprised of porous, permeable, and fossiliferous limestone separated by approximately 10 feet of low porosity limestones, dolomites, and anhydrites (see **Figure 9**).[74] The Sunniland Formation is sealed below by the Punta Gorda anhydrite and above by anhydrites of the Lake Trafford Formation (see **Figures 8** and **9**).[75] The lower Sunniland oil-producing zone (Sunniland D porosity zone) is a dolomite section with fracturing at its base referred to as the "rubble zone." The upper Sunniland also produces oil from porous carbonates (Sunniland C, B, and A porosity zones).[76]

Overlying the Lake Trafford Formation are additional Lower Cretaceous aged limestones, dolomites, and anhydrites (see **Figure 8**). These strata are in turn overlain by Upper Cretaceous aged carbonates and Tertiary aged carbonates and evaporites.[77]

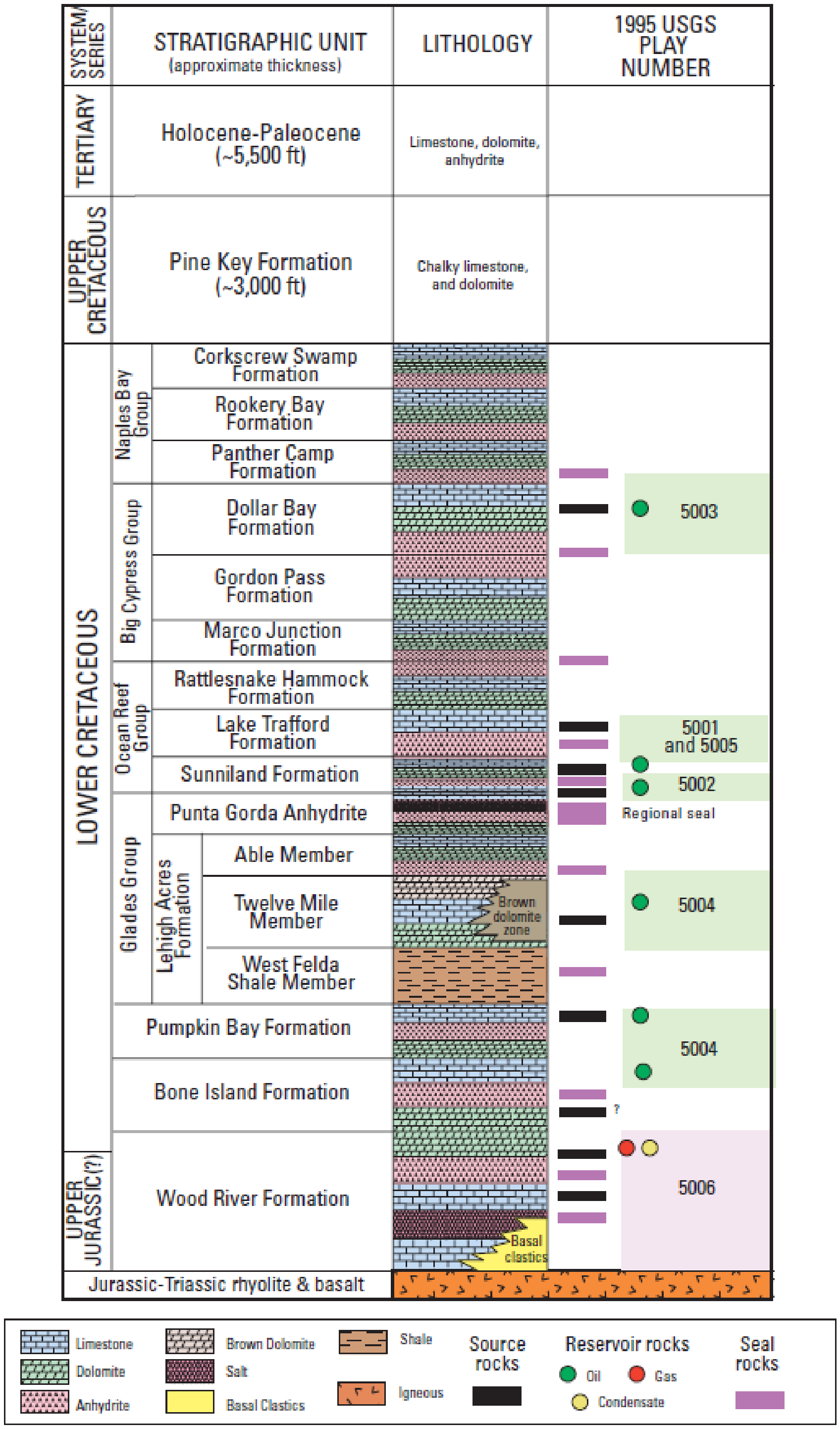

Figure 8: Stratigraphic Column of the South Florida Basin

Source: Richard M. Pollastro, "1995 USGS National Oil and Gas Play-Based Assessment of the South Florida Basin, Florida Peninsula Province," Chapter 2 of *National Assessment of Oil and Gas Project: Petroleum Systems and Assessment of the South Florida Basin*, compiled by Richard M. Pollastro and Christopher J. Schenk, U.S. Geological Survey Digital Data Series 69-A (November 2001), Figure 2, page 3, http://pubs.usgs.gov/dds/dds-069/dds-069-a/REPORTS/SFB1995.pdf (accessed November 18, 2014).

Lower Cretaceous	**Lake Trafford Formation** (anhydrite and non-porous limestone)		
	Sunniland Formation	low porosity limestone	
		Sunniland A (reservoir unit)	
		low porosity limestone	
		Sunniland B (reservoir unit)	
		low porosity limestone	
		Sunniland C (reservoir unit)	
		low porosity limestone	
		~ *Sunniland D* (reservoir unit)	"Black Shale" (dense argillaceous limestone)
			"Rubble Zone"
		argillaceous limestone	
	Punta Gorda Formation (anhydrite)		

Figure 9: Detailed Stratigraphy of the Sunniland Formation

Sources (prepared by ALL Consulting based on information from):

- Albert V. Applegate and Felipe A. Pontigo, Jr., *Stratigraphy and Oil Potential of the Lower Cretaceous Sunniland Formation in South Florida*, Florida Department of Natural Resources, Bureau of Geology, Report of Investigation No. 89 (1984).
- Daniel J. Acquaviva, Omar Rodriguez, and Olga I. Nedorb, "Lehigh Park Field Seen as Indicator of S. Florida Offshore Oil Potential, *Oil and Gas Journal* 108, no. 9 (March 8, 2010).

5.6.2 Sunniland Formation Oil Production

Petroleum production in the South Florida basin began in the early 1940s as the conventional "Upper Sunniland Tidal Shoal Oil Play."[78] The play is a northeast arching structural band 20 miles wide and 150 miles long extending from Fort Meyers to Homestead, Florida. To date, 14 fields have been discovered (see **Figure 10**), all but one (Lake Trafford Field) of which have targeted the upper portion of the Sunniland Formation.[79] The upper zones near the area around the Collier-Hogan 20-3H have produced oil since the mid to late 1940s (see **Figures 10** and **11**). The Sunniland trend has produced a total of 120 million bbls of oil and an indeterminate amount of water.[80,81] Production from the Sunniland has been ongoing for several decades, producing substantial volumes of fluids, indicating that reservoir pressures have declined from their original state at discovery. Recently, there has been a resurgence of active drilling in the upper Sunniland utilizing horizontal drilling techniques.[82]

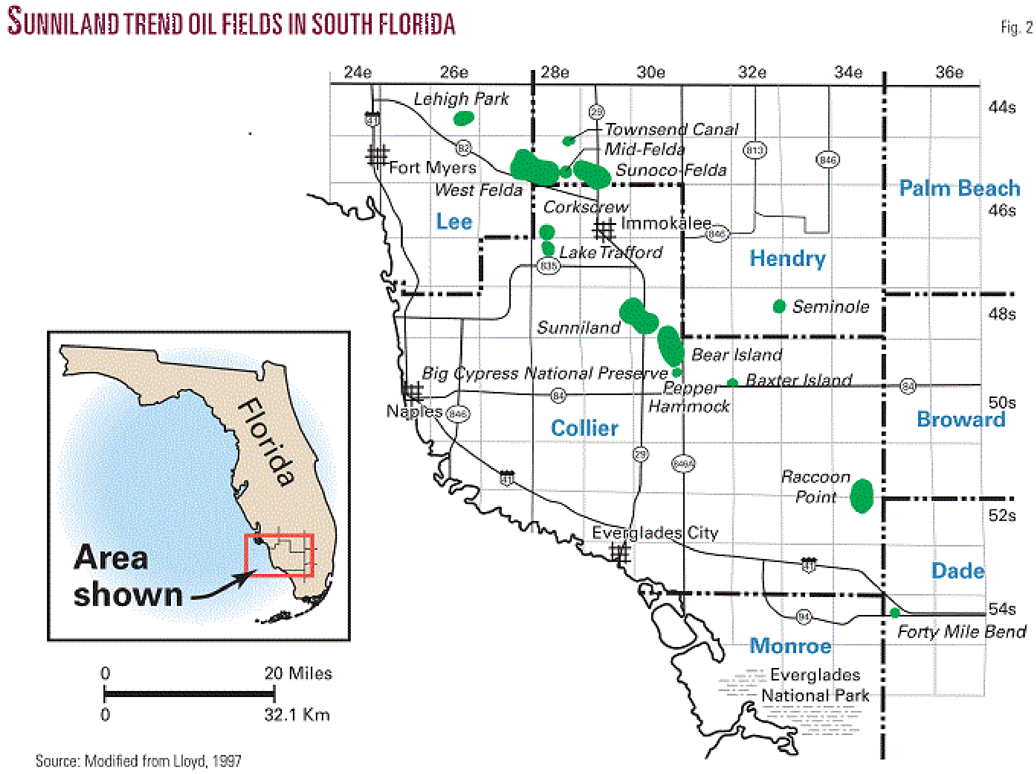

Figure 10: Sunniland Trend Oil Fields in South Florida (aka, USGS Upper Sunniland Tidal Shoal Play 5001)

Source: Daniel J. Acquaviva, Omar Rodriguez, and Olga I. Nedorb, "Lehigh Park Field Seen as Indicator of S. Florida Offshore Oil Potential, *Oil and Gas Journal* 108, no. 9 (March 8, 2010).

The Sunniland D has only been specifically targeted in the Lake Trafford Field. The wells targeting the "D unit" are the Collier-Hogan 20-3H and Well 401, which is approximately 2.5 miles NNE of the Collier-Hogan 20-3H. The lower portion of the Sunniland Formation was first targeted by Well 401 in the late 1960s. This slightly over-pressured well had initial production of 118 barrels of oil per day (bbl/d) and has produced approximately 300,000 bbls of oil since 1969 with no appreciable water.[83]

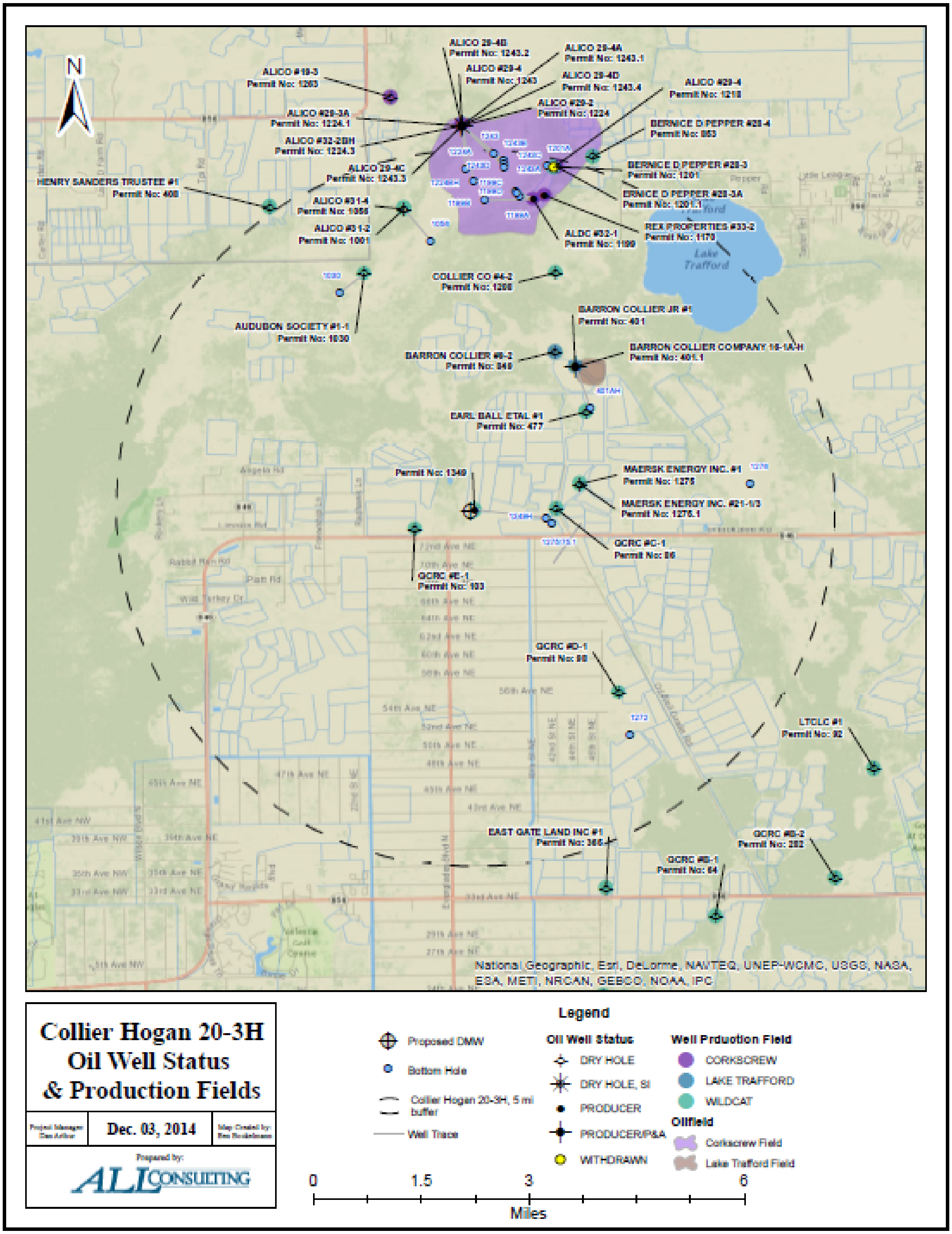

Figure 11: Oil Producing Wells within 5 Miles of the Collier-Hogan 20-3H

5.7 Aquifer Stratigraphy of the Collier-Hogan Area

There are three primary aquifer systems in Florida: the Surficial Aquifer System (SAS), Intermediate Aquifer System (IAS), and Floridan Aquifer System (FAS) (see **Figure 12**). Each is used for water supply throughout the state; however, the SAS and IAS are the primary sources of water in Collier, Hendry, and Lee Counties. In Collier County, more than 90% of the total groundwater withdrawals are from the SAS and IAS.[84] These aquifer systems consist mainly of Cenozoic-aged limestone and dolomite.[85]

Series		Geologic Unit		Approximate thickness (feet)	Lithology
HOLOCENE TO PLIOCENE		UNDIFFERENTIATED		0-70	Quartz sand, silt, clay, and shell
		TAMIAMI FORMATION		0-175	Silt, sandy clay, micritic limestone, sandy, shelly limestone, calcereous sand-stone, and quartz sand
MIOCENE AND LATE OLIGOCENE		HAWTHORN GROUP	PEACE RIVER FORMATION	50-400	Interbedded sand, silt, gravel, clay, carbonate, and phosphatic sand
			ARCADIA FORMATION	400-550	Sandy limestone, shell beds, dolomite, phosphatic sand and carbonate, sand, silt, and clay
EARLY OLIGOCENE		SUWANNEE LIMESTONE		0-600	Fossiliferous, calcarenitic limestone
EOCENE	LATE	OCALA LIMESTONE		0-400	Chalky to fossiliferous, calcarenitic limestone
	MIDDLE	AVON PARK FORMATION		900-1,200	Fine-grained, micritic to fossiliferous limestone, dolomitic limestone, dense dolomite, and gypsum
	EARLY	? OLDSMAR FORMATION		? 800-1,400	
PALEOCENE		CEDAR KEYS FORMATION		500-700	Dolomite and dolomitic limestone
				1,200 ?	Massive anhydrite beds

	Hydrogeologic unit		Approximate thickness (feet)
SURFICIAL AQUIFER SYSTEM	WATER-TABLE AQUIFER		20 -100
	CONFINING BEDS		0-60
	LOWER TAMIAMI AQUIFER		25-160
INTERMEDIATE AQUIFER SYSTEM	CONFINING UNIT		20-100
	SANDSTONE AQUIFER		0 -100
	CONFINING UNIT		10-250
	MID-HAWTHORN AQUIFER		0-130
	CONFINING UNIT		100-400
FLORIDAN AQUIFER SYSTEM		LOWER HAWTHORN PRODUCING ZONE	0-300
	UPPER FLORIDAN AQUIFER		700-1,200
	MIDDLE CONFINING UNIT		500-800
	LOWER FLORIDAN AQUIFER		1,400-1,800
		BOULDER ZONE	400
	SUB-FLORIDAN CONFINING UNIT		1,200?

Figure 12: Relationships between Major Lithostratigraphic and Hydrostratigraphic Units in Southwestern Florida

Source: Ronald S. Reese, *Hydrogeology and the Distribution of Salinity in the Floridan Aquifer System, Southwestern Florida*, U.S. Geological Survey Water Resources Investigations Report 98-4253 (2000), 11, http://fl.water.usgs.gov/PDF_files/wri98_4253_reese.pdf (accessed November 11, 2014).

The SAS is exposed at the land surface and is primarily composed of unconsolidated to poorly indurated siliciclastic sediments that are Lower Miocene to Holocene in age.[86] In Lee and Collier Counties, the SAS contains two discrete aquifers, the water-table aquifer and the lower Tamiami aquifer, separated by confining beds of clay and carbonate muds (see **Figure 12**). Typical thicknesses and depths to the tops of these two aquifers are:

- Water-table aquifer: approximately 20 feet to 100 feet thick; top at approximately land surface.
- Lower Tamiami aquifer: approximately 0 feet to 160 feet thick; top at approximately land surface to 160 feet below sea level.[87]

Overall, the SAS ranges from approximately 20 feet to 300 feet in thickness.[88] The Tamiami aquifer is predominantly made up of sandy, shelly limestone and calcareous sandstones, and occurs within the lower part of the Tamiami Formation.[89]

Typically, the water table is unconfined, but may be locally confined in its deeper portions.[90] Sources of recharge for the SAS include precipitation, seepage from surface water bodies, and upward leakage from the IAS.[91]

The IAS occurs within the Hawthorn Group and is primarily composed of fine-grained siliciclastics interbedded with carbonates ranging from late Oligocene to Miocene in age.[92] The Sandstone and Mid-Hawthorn aquifers are bound and separated by three relatively impermeable (confining) units (see **Figure 12**).[93] Typical thicknesses and depths to the tops of these two aquifers are:

- Sandstone aquifer: approximately 0 feet to 100 feet thick; top at approximately 21 feet to 250 feet below sea level.
- Mid-Hawthorn aquifer: approximately 0 to 130 feet thick; top at approximately 100 feet to 400 feet below sea level.[94]

The IAS is typically on the order of 250 feet to 750 feet thick in southwestern Florida.[95] Sandstone, sandy limestone, and dolomite comprise the sandstone aquifer, while sandy and phosphatic limestones and dolomites make up the mid-Hawthorn aquifer.[96]

The IAS contains confined aquifers.[97] Recharge for the IAS is generally from leakage from the overlying SAS and the underlying FAS.[98]

The FAS is principally comprised of limestone and dolomite that are Paleocene to Lower Miocene in age. It is divided into two (2) aquifers: the Upper Floridan Aquifer System (UFAS) and the Lower Floridan Aquifer System (LFAS). The UFAS and LFAS are separated by the Middle Floridan Confining Unit (MFCU), which consists of both permeable and impermeable units (see **Figure 12**).[99] Typical thicknesses and depths to the tops of these aquifer systems are:

- UFAS: approximately 700 feet to 1,200 feet thick; top at approximately 500 feet to 1,200 feet below sea level.[100,101]
- MFCU: approximately 500 feet to 800 feet thick; top at approximately 1,500 feet to 1,800 feet below sea level.
- LFAS: approximately 1,400 feet to 1,800 feet thick; top at approximately 2,300 feet to 2,700 feet below sea level.[102]

The UFAS is predominantly comprised of limestone.[103] A dense, unfractured dolomite with bedded gypsum or anhydrite is the most impermeable layer within the MFCU. The LFAS is predominantly comprised of limestone and dolomite with dolomite becoming more common with depth. Also within the LFAS is the “Boulder Zone,” a highly permeable, massively bedded, cavernous or fractured dolomite. The top of the "Boulder Zone" is at a depth of approximately 2,900 feet to 3,100 feet below sea level and it is approximately 400 feet thick in Collier County.[104]

The FAS contains generally confined aquifers.[105] The UFAS is under artesian pressure and is well confined above by the Hawthorn Group, but the underlying MFCU provides less effective leaky confinement. Primary groundwater flow zones for the UFAS are in the lower Hawthorn Group and Suwannee Limestone.[106] The "Boulder Zone" in the LFAS contains saline water and is used for injection of wastewater.[107] It has a high transmissivity and takes fluids at low wellhead pressures. Operating conditions at one injection well in south Florida demonstrated transmissivity of approximately 134,000 feet squared per day, and wellhead pressures of less than approximately 20 psi.[108]

Below the FAS is the Sub-Floridan Confining Unit, also called the undifferentiated aquifer systems and confining units (UAS/UCU) (see **Figure 12**). In the Florida peninsula, the uppermost unit of the UAS/UCU is comprised of a sequence of interlayered anhydrite beds and low permeability carbonate rocks that are Paleocene or older in age. These units have low permeability and limit the depth of active groundwater circulation in Florida. However, the understanding of these units is limited due to a lack of available data.[109]

FDEP's regulations define a USDW, which is based off of the Federal definition, as an aquifer in which the groundwater has a total dissolved solid (TDS) concentration of less than 10,000 milligrams per liter and is not an exempted aquifer.[110] The base of the USDW in north central Collier County is at a depth of approximately 1,700 feet to 2,100 feet below sea level (see **Figure 13**).[111] Within the vicinity of the Collier-Hogan 20-3H, the base of the USDW is at a depth of approximately 1,850 below land surface (1,830 feet below sea level).[112] Total dissolved solids (TDS) can be estimated from a resistivity log using the method described by Jorgensen; however, the calculation requires a measurement of drilling mud resistivity (R_m).[113] The dual induction log for the Collier-Hogan 20-3H does not have a value for R_m recorded on the log header. Therefore, there is currently insufficient information to estimate TDS from the induction log in an effort to further refine the depth to base of the USDW at the Collier-Hogan 20-3H well.

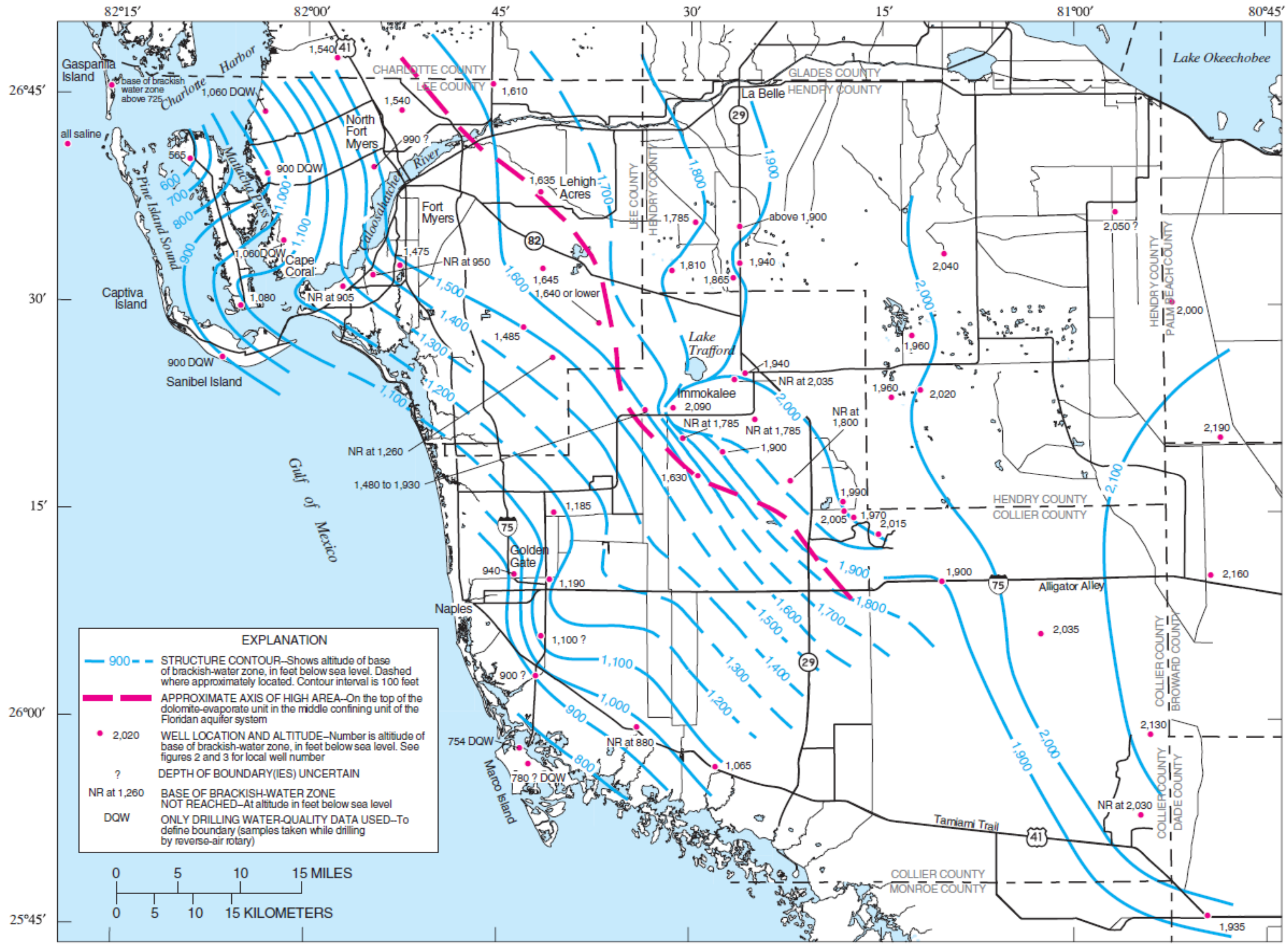

Figure 13: Depth to the Base of the Brackish-Water Zone

Source: Ronald S. Reese, *Hydrogeology and the Distribution of Salinity in the Floridan Aquifer System, Southwestern Florida*, U.S. Geological Survey Water Resources Investigations Report 98-4253 (2000), http://fl.water.usgs.gov/PDF_files/wri98_4253_reese.pdf (accessed November 11, 2014).

5.8 Potential for Impacts to Shallow Freshwater Aquifers

5.8.1 Potential Fluid Migration Pathways

The potential for vertical migration of well stimulation fluids and reservoir fluids during or following a well stimulation job is limited by both the construction of the well in question and by the geology of the intervening geologic strata between the deep hydrocarbon producing reservoir and shallow freshwater-bearing aquifer(s) present in the area. The U.S. EPA[114] and also the Petroleum Technology Alliance Canada (PTAC) in conjunction with the Science and Community Environmental Knowledge Fund (SCEK)[115] have independently considered a range of possible pathways and the practical potential for such vertical migration of stimulation and reservoir fluids to occur. Their extensive analyses have identified the following general pathways along which such upwards vertical migration of fluids could theoretically occur:

1. Defective or deficient well construction that may become further damaged during hydraulic fracturing operations, resulting in compromised mechanical integrity of the well that is being fractured (see **Appendix C**, **Figure C-1**).
2. Induced fracture(s) propagation extending vertically beyond the target reservoir strata (i.e., out of zone) sufficiently far to result in direct or indirect communication with the shallow freshwater aquifer (see **Appendix C**, **Figure C-2**).
3. Normally sealed natural fractures (including faults) that may become activated as a result of hydraulically fracturing a well (see **Appendix C**, **Figure C-3**).
4. Directly through the intervening rock matrix in the absence of natural or induced fractures.
5. Fracture propagation laterally outwards from the shale well a sufficient distance to contact an offset producing well or an improperly plugged well that may have deteriorating cement or casing (see **Appendix C**, **Figure C-4**).

In theory, these generalized mechanisms could provide a conduit of direct or indirect communication between the deep hydrocarbon-bearing reservoir and the shallow freshwater-bearing aquifer. However, in practice the likelihood of this actually occurring is extremely limited. The following paragraphs contain discussion and demonstrations that each of the above potential scenarios is unlikely to occur at the subject site.

It is important to note that the cited U.S. EPA study is only a progress report. One of its purposes was to identify the theoretical range of potential pathways of communication in order to lay the basis for further research and evaluation. It was never intended to provide a full evaluation of those pathways as U.S. EPA's research is not yet complete. Therefore, it would be incorrect for anyone to think that U.S. EPA has concluded that these pathways represent an actual avenue of communication with, and hence a practical threat of impact to, shallow freshwater aquifers.

5.8.1.1 Defective or Deficient Construction of the Hydraulically Fractured Well

Faulty well construction of the well that is being hydraulically fractured (see **Appendix C**, **Figure C-1**) has the greatest potential risk of providing a potential conduit for migration of fracturing fluids or reservoir fluids to impact shallow fresh groundwater.[116] However, even this has a very limited likelihood of occurring for the following reasons:

- State regulations addressing oil and gas well construction are specifically designed to protect freshwater aquifers. These regulations require the installation of surface casing and cement to protect shallow freshwater aquifers and production casing and cement to isolate the target reservoir fluids from potential contact with other strata. Depending on the depth of the well and the need to isolate other zones, additional casing strings may be required.[117,118,119] In accordance with state regulations, tests are conducted to insure the internal integrity of the casing and the external integrity of the cement seal. The very fact that there are no conclusively documented cases of hydraulic fracturing fluids directly impacting a freshwater aquifer via induced fractures provides ample proof of the adequacy of well construction in protecting fresh groundwater.[120]
- Any suggestion that a simple comparison of the hydraulic head in a shallow freshwater aquifer to the head created by pumping hydraulic fracturing fluid into a deep hydrocarbon reservoir and thereby further suggesting that an impact to shallow fresh groundwater would occur is incorrect. A comparison of hydraulic head pressures alone is too simplistic. The factors of fluid density and frictional losses must also be considered. When this is done it becomes evident that it is very unlikely hydraulic fracturing fluid could be lifted to the elevation of the freshwater aquifer.[121] Furthermore, a hydraulic fracturing job is a carefully designed and monitored process with a finite volume of fracturing fluid available in any given stimulation stage. If pumping rates and pressures during the job do not conform to the project design, the stimulation engineer will shut down the pumps, thus terminating the application of increased pressure (head to lift the fluid in the open conduit) and stopping the propagation of fractures and upward flow of fracturing fluid.

The American Petroleum Institute (API) conducted a study on the potential for brine disposal wells to impact shallow freshwater aquifers. This project looked at potentially corrosive brines and well construction practices in 19 producing basins across the United States. It also was focused on examining injection wells in which oil field brines are disposed of over an extended period of time and hence represent greater opportunity for impact than hydraulic fracture stimulations (because of greater volume of fluid injected over a longer period of time—decades for disposal wells versus days for hydraulic stimulation of an oil or gas well). Assuming properly constructed and designed injection wells, the probability of impact to shallow freshwater aquifers was estimated to be between one chance in 200,000 wells and one chance in 200,000,000 wells.[122] PTAC notes that an unconventional oil or gas well would have an even lower likelihood of experiencing a casing leak than an injection well for the following reasons:[123]

- A producing well operates as a pressure sink to draw oil or gas to it, whereas an injection well operates at a constantly elevated positive pressure.
- An injection well disposing of corrosive brines would be subject to greater likelihood of corrosion and damage than would a producing well.
- A producing well is only subjected to elevated pumping pressures for the few days to possibly two weeks during hydraulic fracture stimulation, while an injection well operates at elevated pressure during the entire time it is actively disposing of waste fluids which, over the life of the injection well, can be for several decades.

Note that we have previously addressed well construction in a separate memorandum to FDEP (titled “FDEP FTP File Review Collier-Hogan 20-3H,” and dated October 27, 2014).

5.8.1.2 Vertical Fracture Propagation into a Shallow Freshwater Aquifer

There is a very limited potential for an induced fracture to propagate all the way from a hydrocarbon reservoir up to a shallow freshwater-bearing aquifer (see **Appendix C**, **Figure C-2**) for the following reasons:

- The intervening strata typically include impermeable lithologies that act as confining beds. If such confining beds were not present, the hydrocarbons would not be trapped in the subsurface in the first place.[124]
- In addition to creating and propagating the fracture, fracturing fluids leak off into the formation matrix during a hydraulic fracturing job. This leak-off can consume a substantial portion of the fracturing fluids available to perform a hydraulic fracture job. Because there is limited volume of fracturing fluid available, fracture propagation cannot continue indefinitely.[125]
- The induced fracture propagates along the path of least resistance.[126] So not only will the fracture propagate in a horizontal or vertical direction as dictated by the direction of least principle stress, it will also only propagate through rocks that can be broken by the pressure exerted by the fracturing pumps.
- Induced fractures propagate preferentially through zones of lower stress. Individual rock strata in sedimentary basins can be subject to large variations in magnitude of stress and may also have differing elastic properties. An upwardly propagating fracture tip that encounters a higher stress stratum can be limited if the pumping pressure cannot overcome the stress field of the overlying rock layer. Fracture propagation through an interface between an underlying zone of lower stress and an overlying zone of higher stress would require additional energy. Although it involves complex micromechanics, generally speaking, in the case where sufficient additional energy is not available, continued upward propagation of the fracture would not occur.[127]
- If induced fractures were to propagate vertically out of the hydrocarbon producing zone, they would turn horizontal before reaching the depth of any fresh water aquifer and, hence, never reach that aquifer. Hydraulically induced fractures grow in length perpendicular to the direction of maximum principle stress and widen, or open up, against the least principle stress direction.[128] Above depths of approximately 2,000 feet, the vertical overburden pressure (pressure exerted by weight of the overlying column of rock) is typically the direction of least principle stress; therefore, fracture planes above this depth typically have a horizontal orientation. Below depths of approximately 2,000 feet, the least principle stress has a horizontal orientation because the weight of the overlying column of rock is no longer the direction of least principle stress. Therefore, at depths below 2,000 feet, the fracture plane typically has a vertical orientation.[129,130] Tiltmeter data from over 10,000 hydraulic fracture stimulation jobs demonstrates this, from depths of approximately 4,000 feet upwards to 2,000 feet below grade the horizontal component of fracture propagation becomes the predominant growth direction as the fracture departs from the vertical (see **Appendix C**, **Figure C-7**). The depth of the lower Sunniland Formation (approximately 11,900 feet below grade) at the Collier-Hogan 20-3H assures that fracture propagation could not reach the shallow USDW with its base at approximately 1,850 feet below grade.
- As demonstrated by microseismic monitoring of thousands of hydraulic fracturing stimulation jobs in several different shale plays, induced fractures rarely extend more

than 1,000 feet above the target interval (horizontal leg) of the well. As demonstrated in **Figures C-5** and **C-6** (see **Appendix C**), which compare several thousand hydraulic fracture stimulation jobs in the Marcellus Shale and the Barnett Shale, respectively, there are typically greater than 3,000 feet of vertical separation between the top of the highest induced fracture height and the deepest fresh groundwater aquifer.[131] In the area of the Collier-Hogan 20-3H well, the depth of the horizontal lateral is approximately 11,900 TVD while the lowermost USDW is approximately 1,850 feet deep, resulting in a vertical separation of over 10,000 feet, almost 2 miles.

- Fractures typically do not take the form of single planes of growth; instead they propagate as complex networks of interconnecting fractures. This serves to further limit the maximum vertical propagation length because the fracturing fluid and the fracturing energy are consumed by the growth of the multiple interconnecting fractures that make up the fracture network.[132]
- Hydraulic fracturing jobs, including the pressures and fracture fluid volumes required to create the desired fracture network, are carefully designed. This ensures the efficiency and success of the stimulation job. The equipment, materials, and personnel are costly to employ and so there is great financial incentive against pumping excess fracturing fluids.[133,134]
- Hydraulic fracturing is an intensively monitored process. If an induced fracture were to propagate into a stratum with high porosity and permeability, it would require pumping fracture fluid at increased rates in order to maintain the pressure necessary to continue fracture propagation. In such a case, the stimulation engineer would monitor progress carefully and likely shut down the pumps in the event that excessive pumping were required to maintain necessary pressure or if pressure could not be maintained.
- For an induced fracture to propagate far enough to reach a shallow freshwater aquifer, a greater volume of fracture fluid than is used for any hydraulic fracturing job would be required. Propagation of fractures in any direction (upwards, downwards, or laterally) requires that a substantial volume of fracturing fluid be pumped into the expanding volume of the fracture as it grows. Fisher and Warpinski have clearly demonstrated that fractures of 2,000 feet and greater vertical extent have widths that result in substantial volumes.[135] Assuming that the total fracture fluid volume pumped is available for fracture propagation (i.e., that no leak-off of fracture fluid into the rock matrix occurs), the volume necessary for a fracture to reach shallow freshwater aquifer can be an order of magnitude greater than the volumes typically pumped in a hydraulic fracture stimulation.[136] These are far greater volumes than any company would supply for a hydraulic fracturing job. That amount of fluid would simply not be available at the well site.
- High porosity and permeability strata can also limit upward vertical fracture propagation.[137] A high porosity and permeability stratum, such as a previously produced hydrocarbon reservoir, can act as a thief zone, swallowing up large volumes of hydraulic fracturing fluid. Additionally, a previously produced stratum would have depleted reservoir pressures that also serve to limit fracture propagation by representing a pressure sink that must be overcome to fracture past the zone. Not only are there limited volumes of fracturing fluid available to perform a fracture stimulation, but also, once such a thief zone is encountered and fluid volume is rapidly drawn off, the fracturing pumps will not be able to maintain the flow rates necessary to maintain the elevated pressures required to

continue fracture growth. Thus, the presence of an overlying previously produced stratum can prevent further upward fracture growth. The upper Sunniland Formation represents a potentially regionally pressure depleted formation in this area. The "Boulder Zone" represents an additional pressure sink (see the discussion above concerning wastewater injection into this unit) that could not be fractured through and beyond; however, as noted above, induced fractures could never reach the stratigraphic level of the "Boulder Zone" in the first place.

- The upward vertical extent of induced fracture height at the Collier-Hogan 20-3H well was approximately 14.365 feet, based on modeling by Baker Hughes.[138] This is well within the Sunniland Formation. Therefore, the induced fractures and hydraulic fracturing fluids could not have reached the shallow freshwater aquifer.

5.8.1.3 Activation of Normally Sealed Natural Fractures Including Faults

The points made above for directly fracturing into a shallow freshwater aquifer would also apply to the scenario in which a hydraulic fracture stimulation job were to activate natural but sealed fractures or faults (see **Appendix C**, **Figure C-3**) and thus allow fracture fluids to migrate upwards through such natural pathways to reach shallow fresh groundwater aquifers. Fisher and Warpinski's study on fracture propagation in the Barnett Shale addressed this very issue (see **Appendix C**, **Figure C-6**). They determined that the monitored fractures displaying the greatest vertical height growth correspond to induced fractures contacting faults allowing the observed vertical growth. Because the volume of fracturing fluid pumped in a given hydraulic fracture stimulation stage is limited, fracture growth simply cannot propagate indefinitely upwards.[139]

5.8.1.4 Migration through the Rock Matrix

The potential for migration of hydraulic fracturing fluids through the rock matrix in the absence of natural fractures or other preferential conduits is not possible for the following simple reason: If the permeability of overlying strata were high enough to allow the upward migration of fracturing fluids (typically more dense and viscous than either crude oil or natural gas, heavy degraded crudes being a possible exception), then the hydrocarbons would have already migrated to surface and escaped. There would be no hydrocarbons left trapped in the reservoir rock to explore for and produce. Low permeability sealing strata must be present in order to trap hydrocarbons in reservoir rock. In the case of unconventional source rocks, the reservoir itself is also the sealing trap due to the very low vertical permeability of the rock matrix.[140] However, low permeability sealing strata must also be present above the source rock and below freshwater aquifers, otherwise, over the expanse of geologic time, naturally buoyant hydrocarbons would have migrated upwards and impacted the freshwater aquifer system.

In the Lake Trafford field area, the stratigraphic section separating the Sunniland D at approximately 11,900 feet mean sea level (MSL) and the base of the USDW at approximately 1,850 feet MSL is more than 10,000 feet, or nearly 2 miles.[141,142] The presence of multiple deposits of anhydrite and other low permeability strata throughout this intermediate interval provides a significant impediment to fluid communication between the petroleum-producing zones and usable groundwater. The U.S. Geological Survey (USGS) recognizes regionally continuous seals at the base of the Marco Junction, Dollar Bay, and Panther Camp formations (see **Figure 8**). Additional evaporite strata are located within the Rattlesnake Hammock, Gordon Pass, Rookery Bay, and Corkscrew Swamp formations.[143] Therefore, the presence of multiple sealing strata above the Sunniland preclude upward migration of fluids that could impact the shallow freshwater aquifers.

5.8.1.5 Existing Conduits as Vertical Pathways

An existing conduit could be a natural fracture or an offset well (including an improperly abandoned offset well) with either deficient or defective casing or cement (see **Appendix C**, **Figure C-4**). A simple comparison of the hydraulic head in the freshwater aquifer to the head created by pumping the hydraulic fracturing fluid is sometimes cited as an argument that such communication could occur. However, a comparison of hydraulic head alone is too simplistic; the factors of fluid density and frictional losses must also be considered. When this is done, it is apparent that that hydraulic fracturing fluid is very unlikely to be lifted to the elevation of the freshwater aquifer.[144]

Furthermore, as noted above, a hydraulic fracturing job is a carefully designed and monitored process with a finite volume of fracturing fluid available in any given stimulation stage. If pumping rates and pressures during the job do not conform to the project design, the stimulation engineer will shut down the pumps, thus terminating the application of increased pressure (head to lift the fluid in the open conduit) and stopping the upward flow of fracturing fluid.

Also, as noted above, the probability that brine disposal wells will impact freshwater aquifers is very low (see the discussion concerning defective/deficient well construction), according to an API study.[145]

In the case of the Collier-Hogan 20-3H well, fluid under pressure would have had to travel first at least 993 feet laterally (horizontally) through the formation in order to communicate with the Permit 86 well, the closest abandoned well; however, Baker Hughes' stimulation modeling indicated lateral propagation was limited to 28.884 feet (one wing).[146] Therefore, communication with either of the abandoned legacy wells is not possible.

5.8.2 Permit 86 and 103 Wells

This section provides a technical review of two 1940s oil wells drilled and plugged by Humble Oil & Refining Company, Gulf Coast Realties Corporation Well No.C-1 (Permit 86), and Gulf Coast Realties Corporation "E" Well No. 1 (Permit 103). In addition to evaluating whether the Permit 86 and 103 wells were properly plugged and abandoned, ALL also evaluated the risk of not disturbing the Permit 86 or 103 wells versus the risk of re-plugging either well. The documents used for the basis of this memo were provided by FDEP and included the following:

- Affidavits of plugging completion forms,
- Notices of intention to abandon and plug well forms,
- Well records, and
- "Bottom Plugging Investigation of FDEP [Florida Department of Environmental Protection] Oil Well Permits 86 & 103."[147]

5.8.2.1 Overview of Permit 86 and 103 Legacy Wells

The following basic background information was important when reviewing the records to determine if fracturing fluids could have potentially migrated to these wells as a result of a well stimulation of the Collier-Hogan 20-3H and then travel vertically upwards to impact the USDW:

- Both wells were rotary drilled and subsequently plugged in the late 1940s;

- Both wells were drilled into the Sunniland Formation to a depth of approximately 12,100 feet;
- Commonly used materials and practices for the 1940s were employed in the drilling and plugging of these wells; and
- Neither well's surface casing was set deeper than the base of the deepest USDW (approximately 1,850 feet).[148]

5.8.2.2 Technical Review of Permits 86 and 103 Legacy Wells

In order to fully evaluate whether the wells were plugged in a manner that would prevent well stimulation fluid and/or pressure from the well treatment performed on the Collier-Hogan 20-3H from entering and migrating via the Permit 86 and 103 wells into a USDW, ALL evaluated the following:

- The surface casing and the intermediate casing and production casing strings (with their associated cement volume) that remained in the Permit 86 and 103 wells; and
- The depths and amount of cement used to plug the wellbores.

5.8.2.3 Permit 86 Well Fluid Movement Evaluation

Drilling and completion procedures were reviewed to determine if the 26-inch, 13-3/8-inch, and 9-5/8-inch casing strings were installed to sufficiently prevent fluid movement into the USDW. The following was found:

- The 26-inch casing was set from 78 feet to surface. The top of cement was at surface.
- The 13-3/8-inch casing was set from 1,120 feet to surface. The casing was cemented with 500 sacks of cement. The top of cement was calculated to be at approximately 500 feet below the surface.
- The 9-5/8-inch casing was set from 5,014 feet to surface. The casing was cemented with 500 sacks of cement. The top of cement was calculated to be at a depth of approximately 3,417 feet.
- The "Boulder Zone" (a known LCZ) was encountered at a depth from 2,100 feet to 3,200 feet.[149]

Plugging procedures were reviewed to determine if sufficient casing and cement was in place to prevent fluid movement upward into the lowermost USDW. **Figure 14** is a wellbore schematic of the Permit 86 well from FDEP.

Before the Permit 86 well was plugged on October 23, 1948, sections of the 9-5/8-inch and 5-1/2-inch casings were cut off and removed.[150] The well was plugged as follows:

- The bottom plug was placed at a depth of 11,800 feet on top of an existing cement plug that was set during drilling operations;
- The intermediate plug was placed at a depth of 5,010 feet, which was near the 9-5/8-inch intermediate casing shoe;
- The top plug was set at a depth of 250 feet inside the 13-3/8-inch surface pipe; and
- Heavy drilling mud was placed between the plugs.[151]

ALL prepared **Tables 2** and **3** to show the depths at which the casings where set, the amounts of cement used, the casings in the plugged wells, and the amounts and types of cement used for plugging the Permit 86 well.

The "Boulder Zone" and the lower portion of the USDW were not cemented and the records do not indicate there was a cement plug placed between the two zones. This uncemented interval could have provided a pathway for potential communication of the saline waters from the "Boulder Zone" to the lowermost USDW.

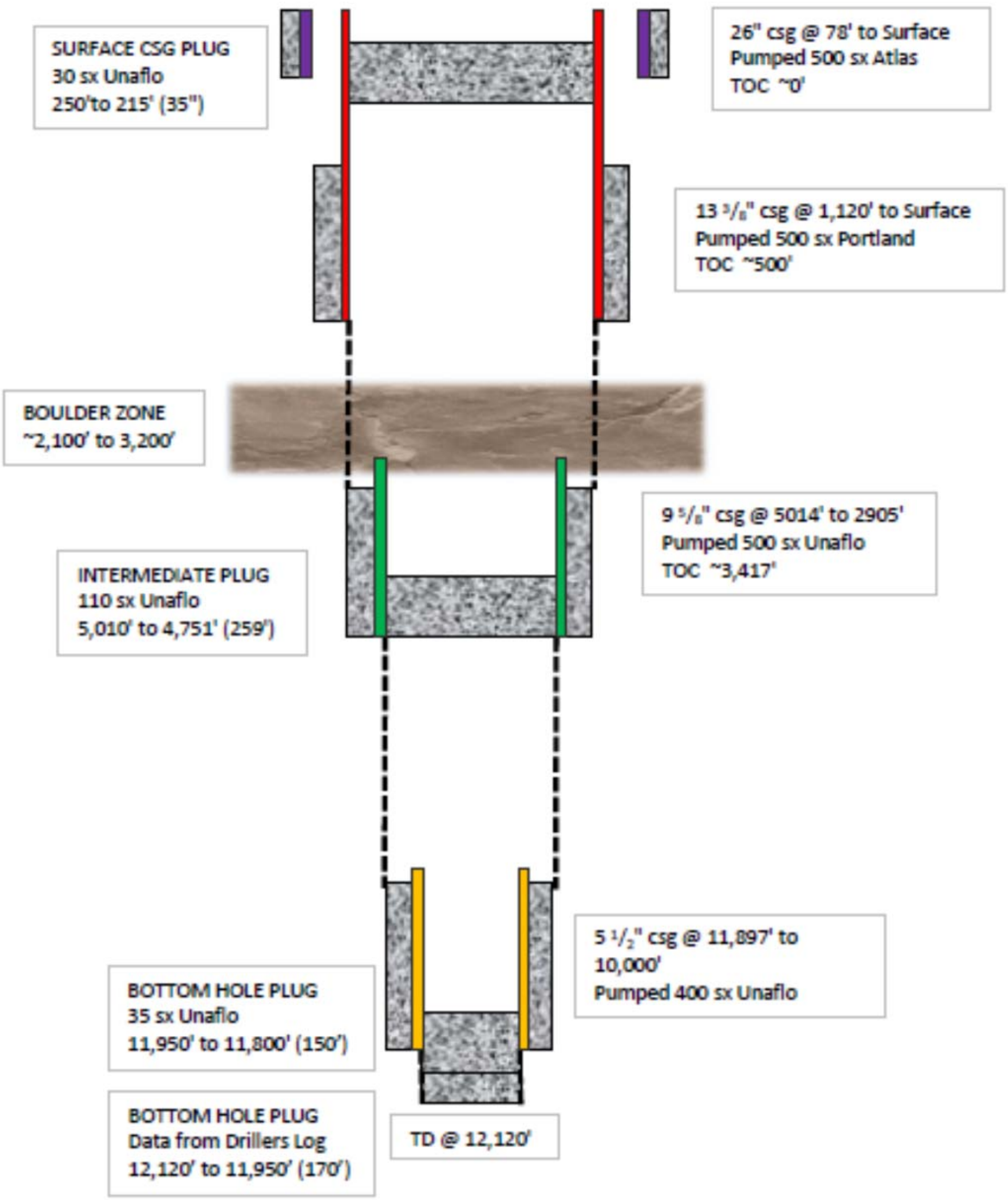

Figure 14: Permit 86 Wellbore Schematic

Source: Owete Owete and Levi Sciara, "Bottom Plugging Investigation of FDEP Oil Well Permits 86 & 103," Florida Department of Environmental Protection (undated), Table 1: Permit 86 Wellbore Schematic.

Table 2: The Pipe with Cement Amounts Left in the Hole Prior to Plugging Permit 86[152]

Outside Casing Diameter (inches)	Top of Casing from surface (feet)	Setting Depth (feet)	Number of Sacks of Cement Used	Type of Cement Used	Top Depth of Casing Left in the Well from Surface (feet)	Bottom Depth of Casing Left in the Well from Surface (feet)
26	0	78	500	Atlas	0	78
13-3/8	0	1,120	500	Portland	0	1,120
9-5/8	0	5,014	500	Unaflo	2,905	5,014
5-½	0	11,897	400	Unaflo	10,000	11,897

Table 3: Placement Locations and Amounts of Cement Used to Plug Permit 86[153]

Plug Description	Depth of Plug Placed Below Surface (feet)	Diameter of Hole or Casing the Plug was Placed (inches)	Number of Sacks of Cement Used	Type of Cement Used
Top plug	250	13-3/8	30	Unaflo
Intermediate Plug	5,010	9-5/8	110	Unaflo
Bottom Hole Plug	11,950	5-1/2	35	Unaflo

The Permit 86 well was plugged and abandoned with three cement plugs in addition to the existing bottom-hole cement plug placed during drilling operations. The three plugs were separated by heavy drilling mud. The heavy drilling mud, bottom cement plugs, and the intermediate cement plug would be sufficient to prevent any fluid movement up the plugged borehole and into the lowermost USDW, based on ALL's and Mr. Arthur's experience. A similar conclusion was reached in "Bottomhole Plugging Investigation of FDEP Oil Well Permits 86 & 103."[154] In addition, it is highly likely that rock formation material has sloughed into the borehole since its plugging and added additional physical barriers in the borehole, which would block upward fluid movement.

For the well stimulation treatment performed in the Collier 20-3H well to have resulted in adverse impact in the lowermost USDW, pressure would have had to travel first at least 993 feet laterally (horizontally) through the formation in order to communicate with the Permit 86 well; however, Baker Hughes' stimulation modeling indicated lateral propagation was limited to 28.884 feet (one wing) (see **Figure 15**). The pressure would then have had to overcome the three cement plugs and the hydrostatic pressure exerted by the heavy drilling mud and forced fluid upward into the USDW. It is highly unlikely that this occurred.

Re-entering the well to drill out the cement plugs to investigate for potential cross-flow conditions is not recommended. The risk of damaging the casings and plugs, thus creating a conduit for potential cross-flow of larger magnitudes, is greater than the benefit of isolating the USDW.

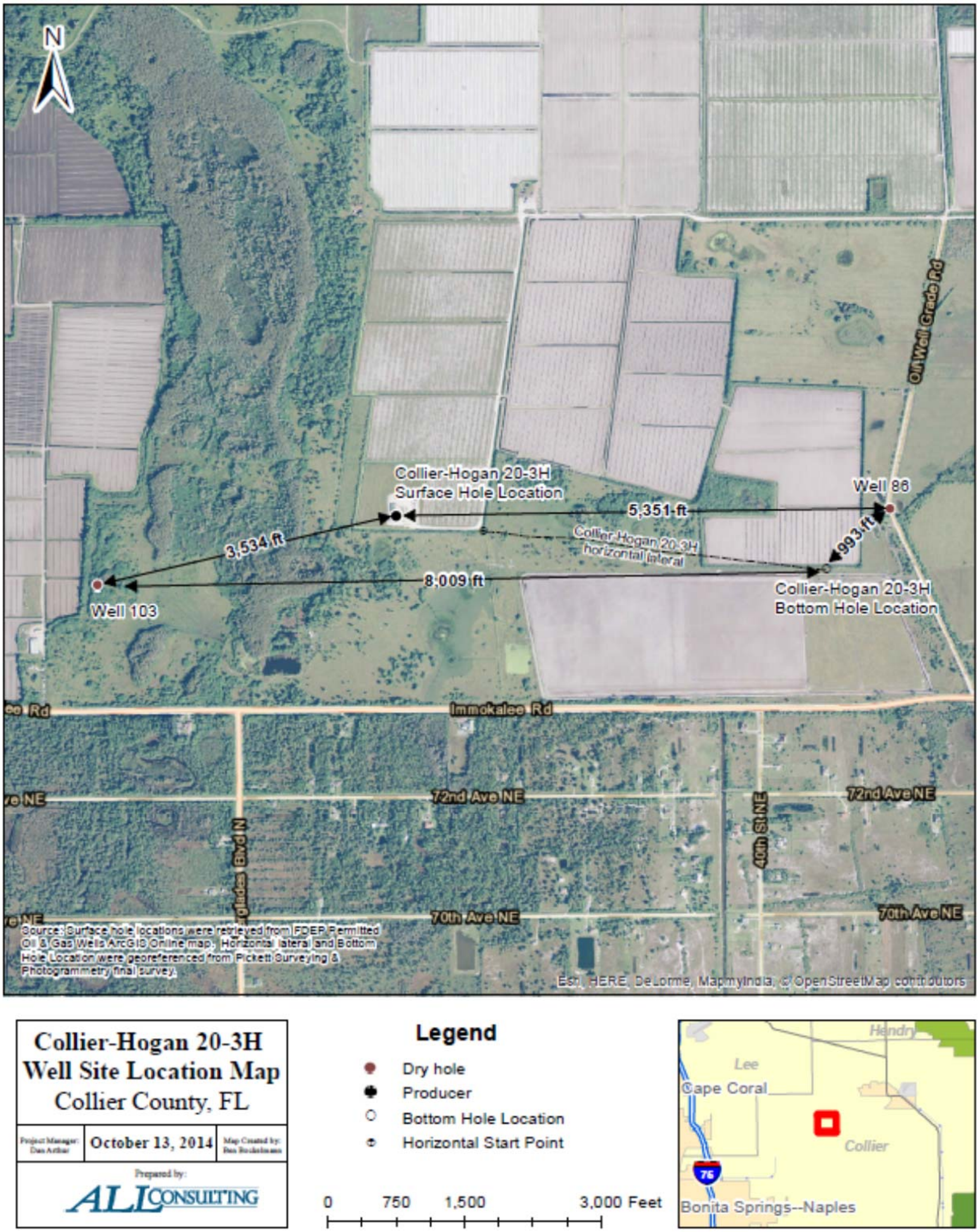

Figure 15: Distances between Wells 86, 103 and Collier-Hogan 20-3H

5.8.2.4 Permit 103 Well Fluid Movement Evaluation

Drilling and completion procedures were reviewed to determine if the casings and cement were in place to sufficiently prevent fluid movement into the USDW.

- The 24-inch casing was set from 73 feet to surface. The top of cement was at surface.
- The 13-3/8-inch casing was set from 966 feet to surface. The casing was cemented with 400 sacks of cement. The top of cement was calculated to be at a depth of approximately 390 feet.
- The 9-5/8-inch casing was set from 4,226 feet to surface. The casing was cemented with 400 sacks of cement. The top of cement was calculated to be at a depth of approximately 2,949 feet.
- The "Boulder Zone" was encountered at depths from 2,100 feet to 3,200 feet.[155]

As with the analysis performed for the Permit 86 well, plugging procedures were reviewed for the Permit 103 well to determine if there were sufficient plugs placed to prevent fluid movement from the lower Sunniland Formation at approximately 12,000 feet to the deepest USDW at approximately 1,850 feet. **Figure 16** is the wellbore schematic of the Permit 103 well provided by FDEP.

The Permit 103 well was plugged and abandoned on July 7, 1949.[156] Unlike for the Permit 86 well, no casing was removed for salvage in the Permit 103 well. Humble attempted to re-enter the Permit 103 well on March 6, 1953. Humble noted on their job order inventory that "Contractor could not drill out cement in top of same," and "Well casing not disturbed."[157] The Permit 103 well was plugged as follows:

- The bottom plug was placed in the well's uncased borehole at a depth of 7,643 feet;
- The intermediate plug was set at 4,226 feet, which was the depth at which the 9-5/8-inch casing shoe was placed; and
- The well was capped with a swage and valve.[158]

ALL prepared **Tables 4** and **5** to show the depths at which the casings were set, the amounts of cement used, the casings in the plugged wells, and the amounts and types of cement used for plugging the Permit 103 well.

Table 4: The Pipe with Cement Amounts Left in the Hole Prior to Plugging Permit 103[159]

Outside Casing Diameter (inches)	Top of Casing from Surface (feet)	Setting Depth (feet)	Number of Sacks of Cement Used	Type of Cement Used	Top Depth of Casing Left in the Well from Surface (feet)	Bottom Depth of Casing Left in the Well from Surface (feet)
24	0	73	500	Atlas	0	73
13-3/8	0	966	400	Portland	0	966
9-5/8	0	4,226	400	Atlas	0	4,226

Table 5: Placement Locations and Amounts of Cement Used to Plug Permit 103[160]

Plug Description	Depth of Plug Placed Below Surface (feet)	Diameter of Hole or Casing the Plug was Placed (inches)	Number of Sacks of Cement Used	Type of Cement Used
Top plug	None	None	None	None
Intermediate Plug	4,226	9-5/8 and unknown borehole size (borehole size not in records)	100	Unaflo
Bottom Hole Plug	7,643	Unknown borehole size (borehole size not in records)	150	Unaflo

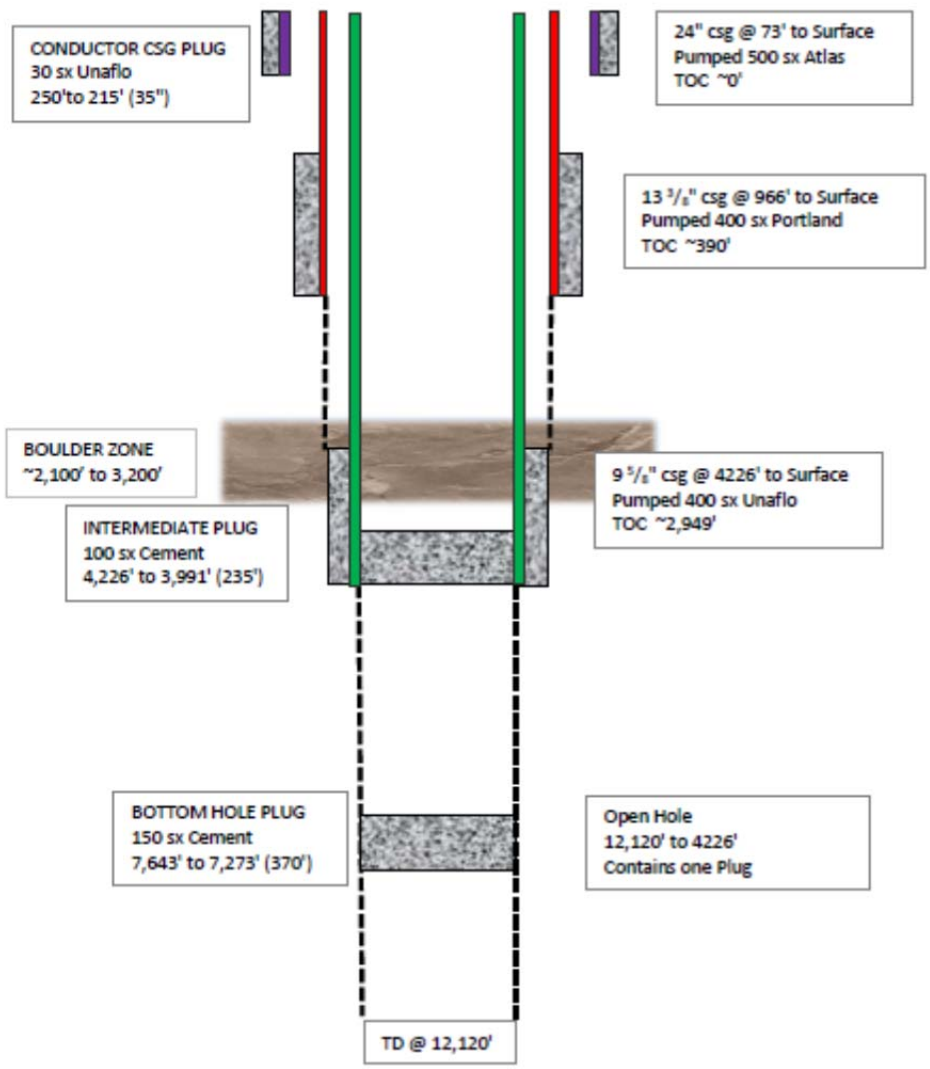

Figure 16: Permit 103 Wellbore Schematic

Source: Owete Owete and Levi Sciara, "Bottom Plugging Investigation of FDEP Oil Well Permits 86 & 103," Florida Department of Environmental Protection (undated), Table 2: Permit 103 Wellbore Schematic.

The bottom of the 9-5/8-inch casing was cemented below the permeable "Boulder Zone." It was likely that when the cement rose to the lower portion of this formation it flowed into the formation instead of covering the upper portion of the "Boulder Zone." The upper portion of the "Boulder Zone" would not have been isolated with cement. The records do not indicate there was a cement plug between the "Boulder Zone" and the uncemented portion of the USDW. This uncemented interval could have provided a conduit for cross-flow between the two zones. The cross-flow could have allowed saline water from the "Boulder Zone" to migrate upward and enter the lowermost USDW.

The Permit 103 well was plugged and abandoned with two cement plugs. The integrity of the cement plug inside the 9-5/8-inch casing could have been comprised when Humble unsuccessfully tried to drill out the plug in 1953. There was nothing in the available records to indicate Humble tested the cement plug for integrity after the failed salvage attempt. There was also no record that Humble placed any additional cement in the casing. The cement plug could have been damaged to the extent of causing a conduit to form. The conduit could have allowed fluids to upward from approximately 7,200 feet (the calculated top of the bottom plug) to the lowermost USDW. The potential for upward migration of fluids could have caused saline fluids to enter the lowermost USDW.

Based on ALL's and Mr. Arthur's experience, the bottom plug would have been sufficient to prevent any fluid movement upwards and into the lowermost USDW. A similar conclusion was reached in "Bottomhole Plugging Investigation of FDEP Oil Well Permits 86 & 103."[161] In addition, it is highly likely that rock formation material has sloughed into the borehole since its plugging and added additional physical barriers in the borehole, which would block upward fluid movement.

For the well stimulation treatment performed in the Collier-Hogan 20-3H to have resulted in adverse impact in the lowermost USDW, pressure would have had to travel first 3,534 feet laterally (see **Figure 15**). The pressure would then have had to overcome the three cement plugs and the hydrostatic pressure exerted by the heavy drilling mud and forced fluid upward into the USDW. It is highly unlikely that this occurred.

It is recommended that the cement plug at approximately 4,200 feet and the 9-5/8-inch casing be tested for integrity. It is also recommended that cross-flow conditions be investigated from 4,200 feet to surface. A pressure MIT and cased borehole acoustic and temperature logs could be used to examine the cement plug and the pipe's internal and external integrity. After concluding the investigation and any remedial work, it is recommended the well be plugged with cement from approximately 1,900 feet to surface. Regardless, based on analysis of the specific technical details applicable to the Collier-Hogan 20-3H workover, it is not likely that opening and re-entering this well (Permit 103) would detect any contamination that may have migrated from the Collier-Hogan 20-3H to the Permit 103 well.

5.8.3 Potential for Surface Releases

In preparation for drilling of the Collier-Hogan 20-3H well, a 300-foot by 300-foot "lime-rock pad" was constructed and partially overlain with a 40-mil thick plastic drilling liner, approximately 145 feet by 110 feet, on January 11, 2013. The liner was penetrated to accommodate the previously emplaced conductor pipe and well cellar. Interlocking polyethylene drilling mats were placed on top of the liner on January 13, 2013.[162] No surface releases were noted in the FDEP inspection reports during drilling.[163]

On May 17, 2013, after the drilling rig was moved from location and the mats had been removed, FDEP inspectors observed surface releases of petroleum products onto the well pad. One release onto the liner was associated with crude oil that dripped from drill pipe and downhole equipment. Two additional releases outside of the area underlain by the drilling liner were associated with oil from the mud pumps of the drilling rig and oil and/or diesel in the generator fueling area.[164]

In total, the 3 stained areas comprised approximately 844 square feet. To address these surface releases, 8 cubic yards of petroleum stained lime-rock were excavated from the 3 areas and stored on a section of 40-mil liner for later transport to a CEMEX incinerator in Miami.[165]

FDEP inspectors noted additional oil-stained lime-rock near the well cellar on August 13, 2013, and attributed it to the first round of well testing. This material was to be excavated and added to the existing 8 cubic yards of material being stored for incineration after the workover was completed.[166]

There were no inspection reports provided to ALL for activities during the workover. During the workover procedure, DA Hughes (work performed by Baker Hughes) injected acid and additives consistent with hydraulic fracturing.[167] Subsequent flowback of stimulation fluids was conducted June 3, 2014, through June 24, 2014, with oil sales through June 22, 2014.[168]

FDEP conducted a site inspection on July 14, 2014, and observed a roll-off container "staged between a canal and a dirt road adjacent to and south of the berm area around the well pad. The dumpster was nearly full with the load consisting of 4" hoses, buckets, pieces of liner and other items, much of which were covered with oil."[169] On the north side of the roll-off bin, oil-stained grass was observed and liquid dripping from the east side of the roll-off bin onto the ground was also observed. Apparent flow of liquids and erosion to the east and into the adjacent canal was observed. The following day the roll-off bin had been removed and a sheen was observed on the water surface in the canal. FDEP sampled soil and water from this area.[170]

Analytical results of soil and surface water sampling were not available for review by ALL. Therefore, there is insufficient information to reach a conclusion regarding potential impacts to the water table aquifer.

A site inspection of the Collier-Hogan 20-3H well pad was performed by ALL and FDEP personnel on Thursday, October 30, 2014 (see Section 5.3 Collier-Hogan 20-3H Site Inspection for further discussion). As noted, ALL and FDEP staff were not granted access to the well pad and performed the inspection from the pad perimeter. ALL observed that an approximate four-to-five-foot wide section of the berm at the northwest corner of the pad had been repaired (note this is not the same area noted above as having been observed by FDEP on July 14, 2014). Storage of chemicals without secondary containment was also noted. No evidence of surface releases was observed. A containment boom was present in the drainage/irrigation ditch on the south side of the pad where it could catch runoff from the ramp leading to the pad, but no evidence of releases was observed.

Overall, it is evident that releases have occurred to the ground surface. There is insufficient information (e.g., analytical results of soil and water samples) to determine if the water table aquifer has been impacted as a result of the DA Hughes activities. Furthermore, based on the currently available information, it would not be possible to determine if any such impact, if it were present, is a direct result of the workover procedure or other activities at the DA Hughes well site.

5.8.4 Water Quality Data

The following text discusses the available groundwater monitoring data for the SAS. We have examined this data to evaluate the potential for the workover stimulation job conducted on the Collier-Hogan 20-3H well to have impacted the freshwater aquifers. Sufficient data to evaluate potential impacts to the IAS and FAS was not available.

5.8.4.1 Collier-Hogan Pad Monitoring Well and Supply Well Data

The Florida Department of Environmental Protection Site Investigation Section (FDEP SIS) installed six monitoring wells near the Collier-Hogan well pad (see **Figure 17**). The monitoring wells were completed in the water table aquifer and sampled on June 25 and 26, 2014. Two pre-existing water supply wells completed in the Lower Tamiami aquifer were also sampled at this time (see **Figures 12** and **18**).[171] Water levels observed at the monitoring wells indicate that flow is generally to the west-southwest across the site (see **Figures 19** and **20**).

Sample results are tabulated in **Table 6**. Only those constituents detected are included in the table. TDS and iron exceeded Secondary Drinking Water Standards (SDWS) at multiple well locations. SDWSs address parameters that may aesthetically degrade water quality (e.g., color, odor, or taste), but are not associated with adverse health impacts. Total recoverable petroleum hydrocarbons, volatile organic compounds, and semi-volatile organic compounds were not detected. The following addresses the observed exceedances of SDWSs:

- Monitoring Wells (completed in the water table aquifer):
  - TDS:
    - TDS concentrations (see **Table 6**) exceeded the SDWS at upgradient well MW-5 (see **Figures 19** and **20**), across-gradient well MW-3, and downgradient well MW-4.
    - Studies of Collier County groundwater from the SAS indicate typical TDS concentrations of 222 mg/L to 3,122 mg/L in the water table aquifer.[172]
    - Sample results at upgradient (i.e., background) well MW-5 were similar to the exceedances observed at the other wells.
    - These data indicate that the TDS concentrations exceeding the SDWS are naturally occurring.
  - Iron:
    - Iron concentrations (see **Table 6**) exceeded the SDWS at all sample locations with concentrations ranging from 1.32 mg/L to 11.7 mg/L.
    - Sample results were highest at upgradient (i.e., background) well MW-5.
    - Studies of the Collier County groundwater from the SAS indicate groundwater concentrations of iron are typically greater than 1 mg/L, which is consistent with the monitoring well sample results.[173]
    - These data indicate that the iron concentrations observed are naturally occurring.
- Supply Wells (completed in the Lower Tamiami aquifer):

- Iron:
  - Iron concentrations (see **Table 6**) exceeded the SDWS at both water supply wells ranging from 2.73 mg/L to 5.07 mg/L.
  - These iron concentrations are consistent with those observed in the water table aquifer monitoring wells.
  - Studies of Collier County groundwater from the SAS indicate groundwater concentrations of iron are typically greater than 1 mg/L, which is consistent with the supply well sample results.[174]
  - These data indicate that the iron concentrations observed are naturally occurring.

No other parameters exceeded Primary or Secondary Drinking Water Standards at the groundwater monitoring and supply wells. Based on these results, there are no indications of adverse impact to the SAS that could be linked to fluids injected during the workover procedure on the Collier-Hogan 20-3H well.

5.8.4.2 Evaluation of Impacts to Intermediate and Floridan Aquifer Systems

Available published water quality data for the IAS and FAS predates the workover procedure conducted at the Collier-Hogan 20-3H well; therefore, these data are only appropriate as baseline background data for comparison to future groundwater quality data from the deep monitoring well that is to be installed.

Table 6: Groundwater Quality Monitoring Results, SAS, June 2014

Analyte/Parameter	Units	Minimum Detection Level	Primary Drinking Water Standard	Secondary Drinking Water Standard	MW-1	MW-2	MW-3	MW-4	MW-5	MW-6	North West Supply Well	South East Supply Well
General Water Quality Parameters												
Total Alkalinity ($CaCO_3$)	**mg/L**	0.65			200	113[A]	93	116	334	94	264	337
Total Ammonia (N)	**mg/L**	0.02		2.8**	0.43	0.68	1.6	0.4	0.49	1.4	0.81	1.1
Total Hardness ($CaCO_3$)	**mg/L**	0.4			234	142	232	261	407	106	272	378
Total Dissolved Solids (TDS)	**mg/L**	15		**500**	377	302	**575**	**593**	**557**	238	386	490[A]
Total Solids	**mg/L**	15			413	333	639	667	599	351	421	522[A]
Anionic Free Radicals												
Chloride (Cl)	**mg/L**	0.2 - 0.4		250	39	37	36	59	63	4.6	42	45
Sulfate (SO_4)	**mg/L**	0.4 - 2.0		250	23	40	190	140	1.1	5.5	20	22
Sulfide (H2S)	**mg/L**	1.00			n/d	n/d	n/d	1.2	n/d	n/d	n/d	n/d
Metals												
Barium (Ba)	**mg/L**	0.0002	2.00		0.0226	0.0206	0.0795	0.0207	0.0281	0.0362	0.0193	0.0234
Calcium (Ca)	**mg/L**	0.075			70.8	41.8	64.7	72.7	154	38.9	99.6	142
Iron (Fe)	**mg/L**	0.030		**0.300**	**1.32**	**3.27**	**3.54**	**1.38**	**11.7**	**2.23**	**2.730**	**5.070**
Magnesium (Mg)	**mg/L**	0.04			13.9	9.28	17.1	19.2	5.2	2.05	5.8	5.82
Potassium (K)	**mg/L**	0.3 - 1.5			8.8	16	48.1	34.1	0.33[I]	6.2	3.7	1.8
Sodium (Na)	**mg/L**	0.5	160		36	30.4	40.9	46.2	18.9	2.3	36.9	29.6

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** The 2.8 secondary standard listed for Ammonia (as N) is a ground water target cleanup level published by FDEP http://www.dep.state.fl.us/waste/quick_topics/publications/wc/brownfields/CompTables/GroundwaterandSurfaceWaterCleanupTargetLevels.pdf (accessed December 3, 2014).

Legend:
Bold values indicate the parameter exceeds the standard.
[A] - Value reported is the mean of two or more determinations.
[I] - The reported value is between the laboratory method detection limit and the laboratory practical quantitation limit.
n/d - Material was analyzed for but not detected. Value is below the method detection limit for the sample analyzed.

Figure 17: Map Showing the Location of Monitor Wells Installed by FDEP SIS

Source: FDEP, "Monitor Well Locations SIS Site # 714 Collier-Hogan Collier County, Florida," provided by FDEP via FTP.

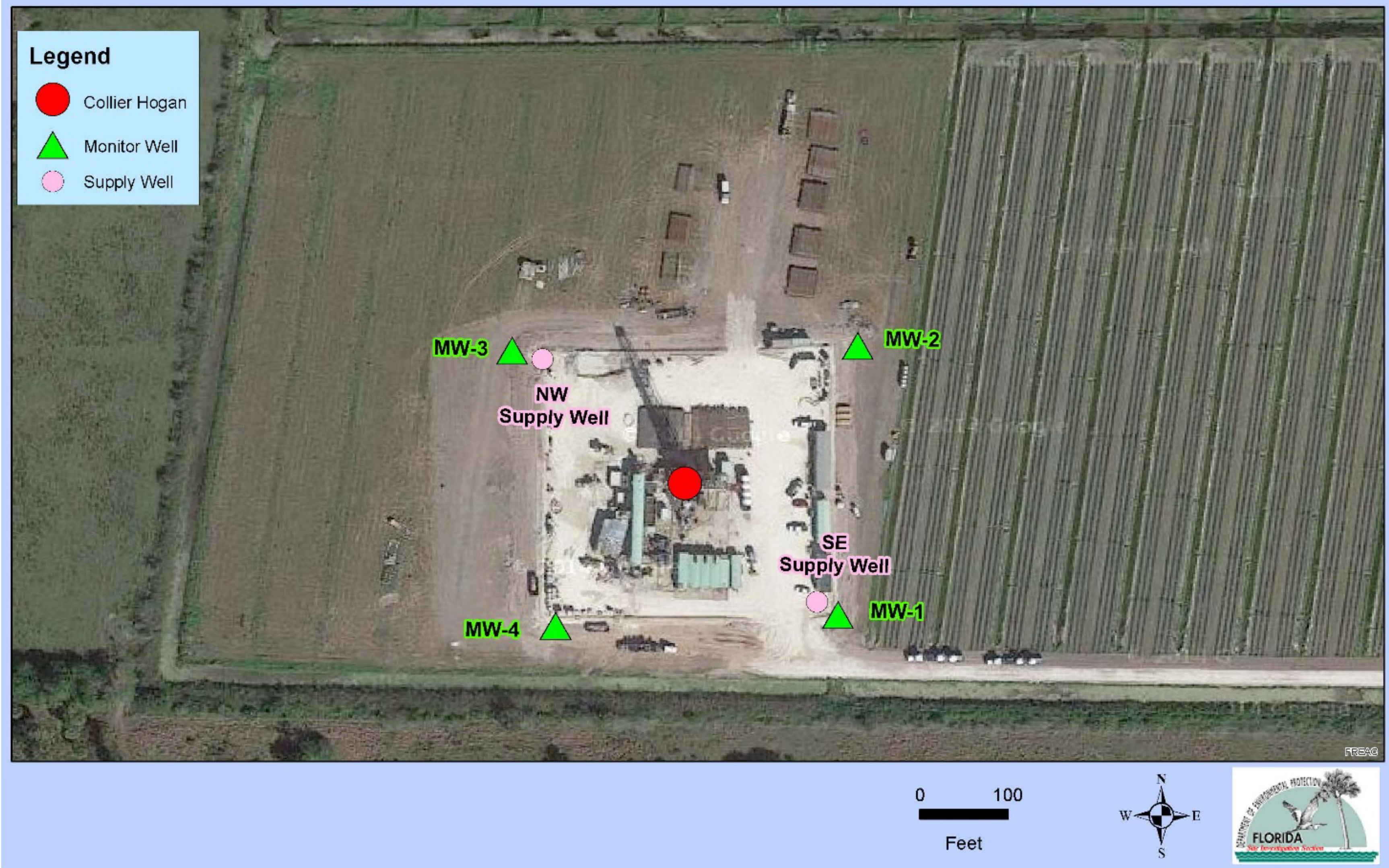

Figure 18: Map Showing the Location of the Water Supply Wells at the Collier-Hogan Well Pad

Source: FDEP, "Monitor Well Locations Closeup SIS Site # 714 Collier-Hogan Collier County, Florida," provided by FDEP via FTP.

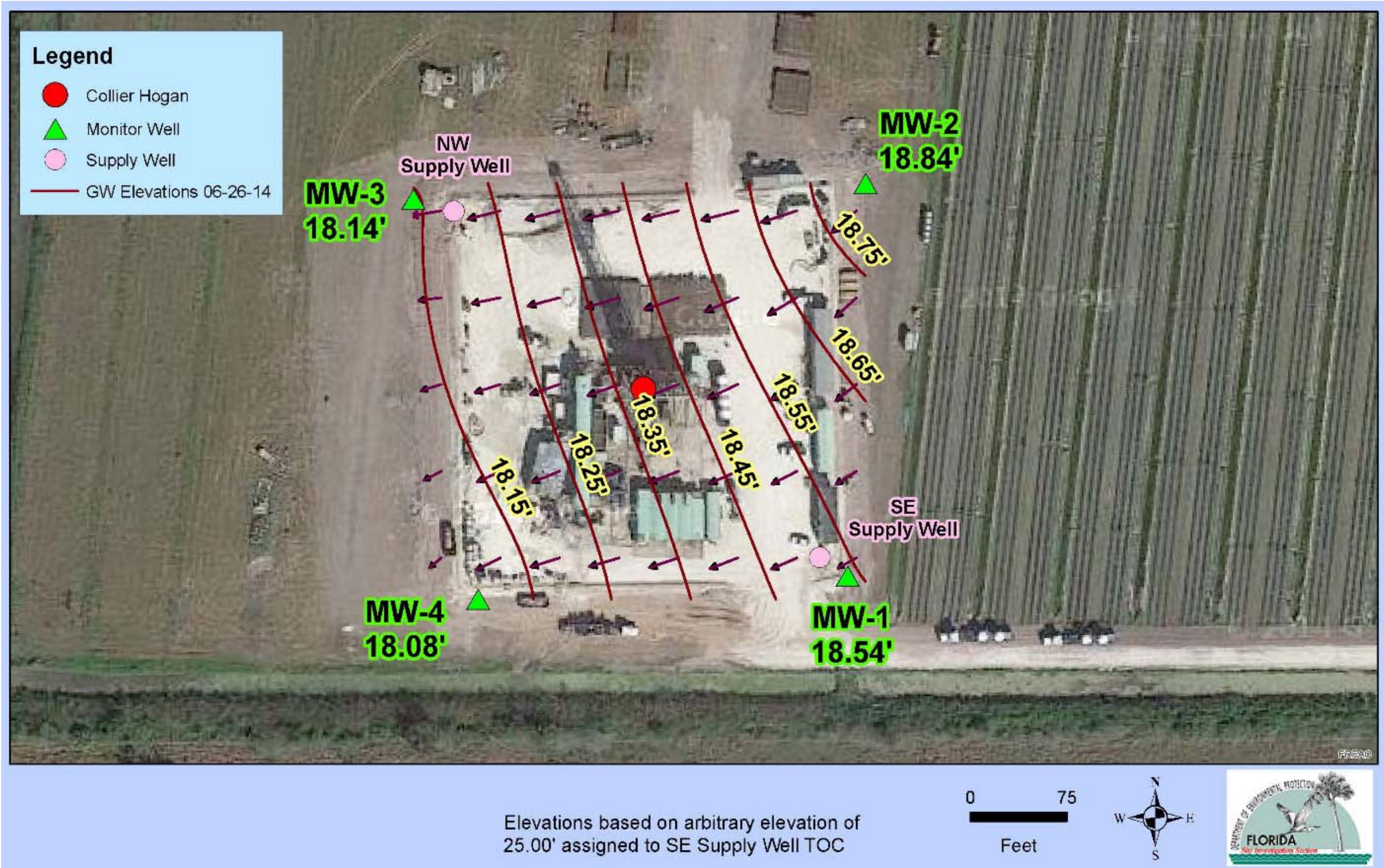

Figure 19: Map Showing Groundwater Elevations Observed on June 26, 2014, and General Flow Direction at the Collier-Hogan Well Pad

Source: FDEP, "Surficial Aquifer Ground Water Elevations June 6, 2014 SIS Site # 714 Collier-Hogan Collier County, Florida," provided by FDEP via FTP.

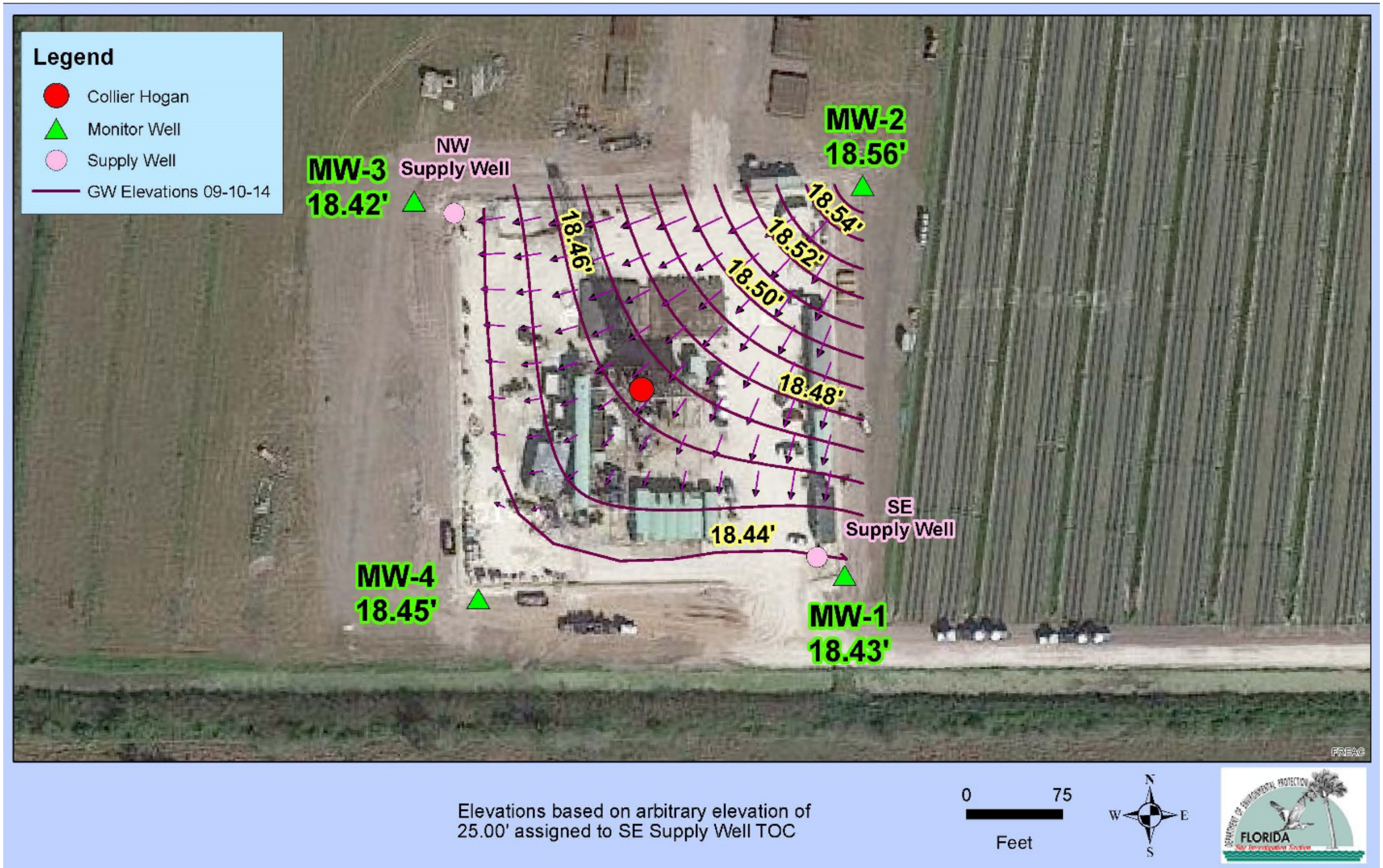

Figure 20: Map Showing Groundwater Elevations Observed on September 10, 2014, and General Flow Direction at the Collier-Hogan Well Pad

Source: FDEP, "Surficial Aquifer Ground Water Elevations September 10, 2014 SIS Site # 714 Collier-Hogan Collier County, Florida," provided by FDEP via FTP.

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APPENDIX A
Documents Provided by FDEP

	File Name	File Type
1	#1349-H (horizontal)-2012 (prelim. site insp.).pdf	Inspection Report
2	#1349-H 2012 (Prelim. Site Insp.).pdf	Annotated Photographs
3	103_Entire_File.pdf	Compiled File
4	12021_1953_3L_93.jpg	Photograph
5	12021_1953_3L_93.jpg	Photograph
6	12021_1953_3L_94.jpg	Photograph
7	12021_1953_3L_95.jpg	Photograph
8	12021_1953_3L_95.jpg	Photograph
9	12021_1953_3L_96.jpg	Photograph
10	12021_1953_3L_96.jpg	Photograph
11	12021_1953_3L_97.jpg	Photograph
12	12021_1953_3L_97.jpg	Photograph
13	12021_1953_3L_98.jpg	Photograph
14	12021_1953_3L_98.jpg	Photograph
15	121012-22_Permit.pdf	Permit
16	130315-13_Permit.pdf	Permit
17	131203-14_LtrMod_20131217.pdf	Letter
18	1349 & 1350 Bond_FM 2A MULT BOND.pdf	Performance Bond
19	1349 Collier-Hogan 20-3H Drilling permit checklist.pdf	Checklist
20	1349 Confidentail Company Daily Drilling Reports.pdf	Status Report
21	1349 core analysis report.pdf	Table
22	1349 DEP Confidential Inspection Rpts.pdf	Inspection Report
23	1349 DP DP FAO 2012.pdf	Permit Order
24	1349 OP FEE.pdf	Receipt
25	1349 OP Published Public Notice.pdf	Letter with Attachments
26	1349-H 2013 Horizontal Operating Permit Inspection.pdf	Inspection Report
27	1349H Application - Collier-Hogan 20-3H (Revised Dec 2012).pdf	Letter and Report
28	1349H Cease and Desist.pdf	Legal Document
29	1349H Close out docs .xlsx	Spreadsheet
30	1349H Final Directional.pdf	Figure
31	1349H Final Survey.pdf	Figure
32	1349H Form 14.pdf	Permit Application Form
33	1349H Form 8.pdf	Well Record
34	1349H Form 9.pdf	Well Completion Report

	File Name	File Type
35	1349H OP Checklist.docx	Checklist
36	1349H OP FAO 2013.pdf	Permit
37	1349H PSInsp_10 25 2012.pdf	Annotated Photographs
38	1349H Wokover 2 Completion Procedure.pdf	Procedure Document
39	1349H Workover 1 Procedure Trade Secret.pdf	Completion Procedure
40	1349H Workover 1 Trade Secret Email.pdf	Email
41	1349H Workover 1 Trade Secret Letter.pdf	Letter
42	1349H Workover 1 Withdrawl.pdf	Email
43	1349H Workover 2 BH Procedure.pdf	Proposal
44	1349H Workover 2 BH Procedure.pdf	Proposal
45	1349H Workover 2 Email.pdf	Email
46	1349H Workover 2 Letter.pdf	Letter
47	1349H Workover Plan-Acid Stimulation.pdf	Procedure Document
48	1349H_CO.pdf	Legal Document
49	1349H_CO_25K_Fine_Redactd.pdf	Check copy
50	1349H_CO_Acknldg_5-6-14.pdf	Email
51	1349H_CO_Chem_List.pdf	Letter with Attachments
52	1349H_CO_Chem_List.pdf	Letter with Attachments
53	1349H_CO_Draft_GWMP_5.6.2014.pdf	Report
54	1349H_CO_GWMP_6.13.14.pdf	Report
55	1349H_CO_GWMP_6.13.14_DEP COMMENTS.pdf	Report with Comments
56	1349H_CO_GWMP_7.7.14.pdf	Report
57	1349H_CO_GWMP_7.7.14_Attach.pdf	Figure
58	1349H_CO_GWMP_7.7.14_DEP COMMENTS.pdf	Email
59	1349H_CO_GWMP_7.7.14_Letter.pdf	Email
60	1349H_CO_Letter_4-27-14.pdf	Letter
61	1349H_CO_Letter_5-6-2014.pdf	Letter
62	1349H_CO_Letter2.pdf	Letter
63	1349H_CO_Letter2.pdf	Letter
64	1349H_CO_PPG 14 and 15 Review Letter_5-6-14.pdf	Email
65	1349H_CO_RAIDER PERMIT.pdf	Permit
66	1349H_CO_RAIDER PERMIT2.pdf	Permit
67	1349H_CO_RESPONSES.pdf	Email
68	1349H_CO_Revised_GWMP_6-13-14.pdf	Report
69	1349H_CO_SPCC_6.12.14.pdf	Report
70	1349H_CO_SPCC_6.25.14.pdf	Report

	File Name	File Type
71	1349H_CO_SPCC_6.25.14_DEP COMMENTS.pdf	Email
72	1349H_CO_SPCC_7.10.14.pdf	Report
73	1349H_CO_SPCC_7.10.14_DEP COMMENTS.pdf	Email
74	1349H_CO_SPCC_7.14.14 Attachment.pdf	Pages from Report
75	1349H_CO_SPCC_7.14.14.pdf	Report
76	1349H_CO_SPCC_INTERIM.pdf	Report
77	1349H_CO_SPCC_INTERIM_DEP COMMENTS.pdf	Email
78	1349H_CO_SPCC_Letter.pdf	Email
79	1349H_CO_SPCC_PE_Certifed_6-26-14.pdf	Pages from Report
80	1349H_CO_SPCC_SIGN.pdf	Pages from Report
81	1349H_CO_Water_Use.pdf	Permit
82	1349H_CO_Water_Use.pdf	Permit
83	13802 ft_pilot hole_triple-combo_COLLIER_HOGAN_20_3H_RUN1_IIIC_CLR.pdf	Form
84	1449H_CO_Req_Mtg-5-8-14.pdf	Email
85	6.27.14 Hughes.pdf	Letter
86	6.30.14 Hughes.pdf	Letter
87	7.1.14 Hughes.pdf	Letter
88	7.10.14 DEP Press Release.pdf	Email
89	7.13.14 Riley Email.pdf	Email
90	7.17.14 Hughes.pdf	Letter
91	7.3.14 DEP Press Release.pdf	Email
92	7.30.14 Tom Jones.pdf	Letter
93	7.9.14 Gable Flood.pdf	Letter
94	7.9.14 Tom Jones.pdf	Letter
95	86 and 103 links to Oculus.docx	Links
96	86_Entire_File.pdf	Compiled File
97	9-3-14 Collier Quotes Deep Well Installation.pdf	Request for Quotes
98	AECOM Collier O&G Report.pdf	Report
99	Ag Use.xlsx	Spreadsheet
100	All Results.xls	Spreadsheet
101	All Webbs Quote Collier County.pdf	Email
102	Attorney Work Product - Access Agreement.pdf	Email
103	Big Cyp Committee Memo to Vinyard.pdf	Memorandum
104	Blanket Bond RLB0014778.pdf	Performance Bond
105	Blanket Bond RLB0014778.pdf	Performance Bond

	File Name	File Type
106	cc petition for administrative hearing.hughes0000.pdf	Legal Document
107	Cement Bond.tif	Log
108	Chemical List.xlsx	Spreadsheet
109	Collier Hogan Well_Collier County Property Appraiser_Jan 2014_sde031542821912172710.jpg	Photograph
110	Collier Resources Lease Termination.pdf	Letter
111	COLLIER WATER METER USAGE.xlsx	Spreadsheet
112	Collier Well Specifications.pdf	Email
113	Collier Well Specifications_AdditionalSiteFigureCloseUp.pdf	Email
114	Collier-Hogan Monitor Well Analyte List.pdf	Analyte List
115	Collier-HoganPA10-8-14.pdf	Figure
116	Consultant Responsibilities.pdf	Memorandum
117	Copy of Detects Working File.xlsx	Spreadsheet
118	Copy of Detects.xlsx	Spreadsheet
119	Dan A. Hughes Collier - Hogan 20 # 3-H (Book 5).xlsx	Spreadsheet
120	Dan Hughes 1349H Analytical Groundwater Summary Table.xls	Spreadsheet
121	Dan Hughes 1349H Consent Order 1-13-14.doc	Memorandum
122	Detects.xls	Spreadsheet
123	DRAFT TANK SCHEMATICS.pdf	Figure
124	Drilling and Cementing Reports.pdf	Report
125	Dual GR-CCL #1.tif	Log
126	Dual GR-CCL #2.tif	Log
127	Dual Ind LL3.tif	Log
128	FM 1_DAN HUGHES CO .pdf	Organization Report
129	Form 16. P&A Pilot Hole, Collier Hogan 20-3H.pdf	Completion Notice
130	Geological Cutting & Core Samples.pdf	Email
131	Geological Cutting & Core Samples.pdf	Email
132	GR.tif	Log
133	Ground Water Elevations 06-26-14.pdf	Figure
134	Ground Water Elevations 09-10-14.pdf	Figure
135	HRP Remediation SOQ.pdf	Statement of Qualifications
136	HUGHES LEAVES.pdf	Email
137	IMG_3341.jpg	Photograph
138	IMG_3342.jpg	Photograph
139	IMG_3343.jpg	Photograph
140	IMG_3344.jpg	Photograph

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201	IMG_4276.jpg	Photograph
202	IMG_4349.jpg	Photograph
203	IMG_4350.jpg	Photograph
204	IMG_4351.jpg	Photograph
205	IMG_4352.jpg	Photograph
206	IMG_4353.jpg	Photograph
207	IMG_4354.jpg	Photograph
208	IMG_4355.jpg	Photograph
209	IMG_4356.jpg	Photograph
210	IMG_4357.jpg	Photograph
211	IMG_4358.jpg	Photograph
212	IMG_4359.jpg	Photograph

	File Name	File Type
213	IMG_4360.jpg	Photograph
214	IMG_4361.jpg	Photograph
215	IMG_4362.jpg	Photograph
216	IMG_4363.jpg	Photograph
217	IMG_4364.jpg	Photograph
218	IMG_4365.jpg	Photograph
219	IMG_4366.jpg	Photograph
220	IMG_4367.jpg	Photograph
221	IMG_4368.jpg	Photograph
222	IMG_4369.jpg	Photograph
223	IMG_4370.jpg	Photograph
224	IMG_4371.jpg	Photograph
225	IMG_4372.jpg	Photograph
226	IMG_4373.jpg	Photograph
227	IMG_4374.jpg	Photograph
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229	IMG_4376.jpg	Photograph
230	IMG_4377.jpg	Photograph
231	IMG_4378.jpg	Photograph
232	IMG_4379.jpg	Photograph
233	IMG_4380.jpg	Photograph
234	IMG_4381.jpg	Photograph
235	IMG_4382.jpg	Photograph
236	IMG_4383.jpg	Photograph
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241	IMG_4388.jpg	Photograph
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243	IMG_4390.jpg	Photograph
244	IMG_4391.jpg	Photograph
245	IMG_4392.jpg	Photograph
246	IMG_4393.jpg	Photograph
247	IMG_4394.jpg	Photograph
248	IMG_4395.jpg	Photograph

	File Name	File Type
249	IMG_4396.jpg	Photograph
250	IMG_4397.jpg	Photograph
251	Inspection Reports.pdf	Inspection Report
252	Interested Party Letters.pdf	Letter
253	Intermediate Questions and SIS Answers to All Webbs.pdf	Email
254	Layne Intermediate Questions and SIS Response.pdf	Email
255	Layne Quote Collier County Monitor Well.pdf	Email
256	Layne Quote Specifications.pdf	Request for Quotes
257	Layne Quote_AdditionalQuestions.pdf	Email
258	Monitor Well Locations All.pdf	Figure
259	Monitor Well Locations Pad CH.pdf	Figure
260	Monitoring Well Work Plan.pdf	Report
261	Notice of Revocation DEP v. Hughes OGC Case 14-0400 7-18-14.pdf	Legal Document
262	P 86 6-5-69 notes.pdf	Notes
263	P 86 DST.pdf	Test Record
264	P 86 Whole File.pdf	Compiled File
265	P-1349_CO_Requirmt_Tracker_6-27-14.doc	Table
266	Pad & Survey.pdf	Email
267	Permit 1349 FAQs.doc	FAQ Sheet
268	Permit 86 & 103 Investigation v7.pdf	Report
269	Petition For Enforcement and Complaint.pdf	Legal Document
270	Production.pdf	Table
271	Proposed Sandstone Aquifer Monitor Well.pdf	Figure
272	questions by Collier consultant.docx	Notes
273	Questions Letter from Garrett.pdf	Letter
274	RAI_Hughes Workover.docx	Letter
275	Ranger SOQ.pdf	Statement of Qualifications
276	RFI Proposal.pdf	Request for Information
277	RFI.pdf	Request for Information
278	RFI_Notes_9.5.14_LS.docx	Notes
279	S.U. BOPs.pdf	Figure
280	SDS - FRW-18 kjg added 121614.pdf	MSDS
281	SDS - NE-945.pdf	MSDS
282	SDS - XLW-30G.pdf	MSDS
283	SDS-15% HCL.pdf	MSDS

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284	SDS-15% HCL.pdf	MSDS
285	SDS-Alpha 1427.pdf	MSDS
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288	SDS-AsphaltSorb 5000.pdf	MSDS
289	SDS-BC-3.pdf	MSDS
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292	SDS-BF-9L.pdf	MSDS
293	SDS-CI-31.pdf	MSDS
294	SDS-CI-31.pdf	MSDS
295	SDS-Enzyme G-I.pdf	MSDS
296	SDS-Enzyme G-I.pdf	MSDS
297	SDS-Ferrotrol 300L.pdf	MSDS
298	SDS-Ferrotrol 300L.pdf	MSDS
299	SDS-GBW-23.pdf	MSDS
300	SDS-GBW-23.pdf	MSDS
301	SDS-GBW-5.pdf	MSDS
302	SDS-GBW-5.pdf	MSDS
303	SDS-GW-3LDF.pdf	MSDS
304	SDS-GW-3LDF.pdf	MSDS
305	SDS-NE-945.pdf	MSDS
306	SDS-NE-945.pdf	MSDS
307	SDS-ParaSorb 5000.pdf	MSDS
308	SDS-ParaSorb 5000.pdf	MSDS
309	SDS-Sand, White-20-40.pdf	MSDS
310	SDS-Sand, White-20-40.pdf	MSDS
311	SDS-Sand, White-30-50.pdf	MSDS
312	SDS-Sand, White-30-50.pdf	MSDS
313	SDS-XLD-1.pdf	MSDS
314	SDS-XLD-1.pdf	MSDS
315	SDS-XLW-30G.pdf	MSDS
316	SDS-XLW-30G.pdf	MSDS
317	SIS-2014-06-27-02.pdf	Chemical Analysis Report
318	Summons.pdf	Legal Document
319	Temp.tif	Log

	File Name	File Type
320	WOODWARD CLYDE Abandoned Well 1993 FINAL RPT.pdf	Report
321	WOODWARD CLYDE Abandoned Wells Project Appendices 2 of 3.pdf	Report
322	WOODWARD-CLYDE O&G Plugging Rpt - final.pdf	Report
323	WOODWORD CLYDE Abandoned Wells Proj V. 1 of 3.pdf	Report
324	Workover Analysis Report (Main Test, figs, and tables).pdf	Report
325	Workover Analysis Report.pdf	Report
326	XY_CAL_GR.tif	Log

APPENDIX B
Site Visit Photo Log

Photograph 1

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Dan Arthur and Paul Attwood discussing location of equipment during drilling and present configuration. Jeff Glenn and Danielle Irwin in background.

Photograph 2

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Paul Atwood (FDEP) in foreground

Photograph 3

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Site overview, frac tanks (7) at left

Weatherford Rotoflex pumping unit at center

Tank battery (6 @ 400 bbl and 1 @ 500 bbl) at right

Photograph 4

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Weatherford Rotoflex pumping unit at left

Tank battery (6 @ 400 bbl and 1 @ 500 bbl) at center

Signage and freight storage unit at right

Photograph 5

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Close-up of Weatherford Rotoflex pumping unit

Photograph 6

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Close-up of Tank battery (6 @ 400 bbl and 1 @ 500 bbl)

Photograph 7

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Dan Arthur next to FDEP shallow monitoring well housing (outside berm)

Photograph 8

Time: 9:45 – 9:55 am

Location: SE side of Collier Hogan Well Pad

Notes: Dan Arthur next to FDEP shallow monitoring well housing (outside berm)

Photograph 9

Time: 9:45 – 9:55 am

Location: East side of Collier Hogan Well Pad

Notes: Tank Battery – contractor and equipment in foreground

Photograph 10

Time: 9:55 – 10:05 am

Location: East side of well pad - northern end

Notes: Equipment in foreground Tank Battery at right

Photograph 11

Time: 9:55 – 10:05 am

Location: East side of well pad - northern end

Notes: Equipment in foreground

Tank Battery at center showing liner and noted recent work

Photograph 12

Time: 9:55 – 10:05 am

Location: East side of well pad - northern end

Notes: Tank Battery at center showing liner and noted recent work

Photograph 13

Time: 9:55 – 10:05 am

Location: East side of well pad - northern end

Notes: Close up of Tank Battery at center showing liner and noted recent work

Photograph 14

Time: 9:55 – 10:05 am

Location: East side of well pad - northern end

Notes: Dan Arthur with pipe and liner on berm over left shoulder

Pipe laying on liner and possible damage to same

Tank Battery at center showing liner and noted recent work

Photograph 15

Time: 9:55 – 10:05 am

Location: East side of well pad - northern end

Notes: Pipe laying on liner and possible damage to same communication to Danielle Irwin

Tank Battery at center showing liner and noted recent work

Photograph 16

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: FDEP shallow monitoring well (13 ft deep per Paul Attwood)

Photograph 17

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: FDEP shallow monitoring well (13 ft deep per Paul Attwood)

Photograph 18

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Facility elements as previously described

Photograph 19

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Lots of notes - instructions on completeness, detail and accuracy

Photograph 20

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Lots of notes - instructions on completeness, detail and accuracy

Photograph 21

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Facility elements as previously described

Photograph 22

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: FDEP shallow monitoring well (13 ft deep per Paul Attwood)

Photograph 23

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: More note taking

Photograph 24

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Dan Arthur with Tank Battery in Background

Photograph 25

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Tank Battery with Pumping Unit in Background

Photograph 26

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Close-up of Tank Battery with Pumping Unit in Background

Photograph 27

Time: 9:55 – 10:05 am

Location: NE corner of well pad

Notes: Tank Battery with Pumping Unit in Background

Photograph 28

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: Tank Battery (400 bbl at left, with 500 bbl at right)

Photograph 29

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: Tank Battery (400 bbl with cat walk and stairs)

Photograph 30

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: Tank Battery (400 bbl with cat walk and stairs)

Pumping unit - at right

Photograph 31

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: Pumping unit with stairs in foreground

Harness not connected to rod assembly (not capable of activating till reconnected – indication of long term shut-in)

Photograph 32

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: Dan Arthur with binoculars noting presence of pressure gauges with open valves and zero pressure on tubing and annular

Photograph 33

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: Tank Battery (500 bbl with cat walk and stairs)

Gravel pile at right

Photograph 34

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: No distressed vegetation

Photograph 35

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: No distressed vegetation

Photograph 36

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: No distressed vegetation

Photograph 37

Time: 10:10 – 10:20 am

Location: North side of well pad

Notes: No distressed vegetation

Photograph 38

Time: 10:20 am

Location: North side of well pad - NW corner

Notes: Breached berm with subsequent fill

Photograph 39

Time: 10:20 am

Location: North side of well pad - NW corner

Notes: Breached berm with subsequent fill

Photograph 40

Time: 10:20 am

Location: North side of well pad - NW corner

Notes: Breached berm with subsequent fill

Photograph 41

Time: 10:20 am

Location: North side of well pad - NW corner

Notes: Breached berm with subsequent fill

Photograph 42

Time: 10:20 am

Location: North side of well pad - NW corner

Notes: Breached berm with subsequent fill

Photograph 43

Time: 10:20 am

Location: North side of well pad - NW corner

Notes: Water supply well for Collier Hogan Drilling

Photograph 44

Time: 10:20 – 10:25 am

Location: North side of well pad - NW corner

Notes: Looking down west side toward south (berm intact - vegetation as expected)

Photograph 45

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: FDEP monitoring well

Photograph 46

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: FDEP monitoring well

Dan Arthur and Danielle Irwin

Photograph 47

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: Near FDEP monitoring well (low spot with evaporated water/mud)

Danielle Irwin

Photograph 48

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: FDEP monitoring well

Vegetation not distressed

Photograph 49

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: FDEP monitoring well

Vegetation not distressed

Photograph 50

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: Vegetation not distressed (looking NW)

Photograph 51

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: Near FDEP monitoring well (low spot with evaporated water/mud tire tracks suspected from monitoring well rig)

Danielle Irwin and Dan Arthur

Photograph 52

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: Near FDEP monitoring well (low spot with evaporated water/mud tire tracks suspected from monitoring well rig)

Photograph 53

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: Near FDEP monitoring well (low spot with evaporated water/mud tire tracks suspected from monitoring well rig)

Photograph 54

Time: 10:20 – 10:25 am

Location: NW corner of well pad

Notes: Near FDEP monitoring well (looking SW)

Photograph 55

Time: 10:20 – 10:25 am

Location: West side of well pad

Notes: Liner (Paul Attwood took sample of liner)

Photograph 56

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Notation of freshly painted tanks (buckets noted, and reference to prior photos and site visit by Danielle Irwin reference notation of PE seal and fiberglass by Levi Sciara. (Holes and tears in plastic on battery from this vantage)

Photograph 57

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Notation of freshly painted tanks (buckets noted, and reference to prior photos and site visit by Danielle Irwin reference notation of PE seal and fiberglass by Levi Sciara. (Holes and tears in plastic on battery from this vantage)

Photograph 58

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Notation of freshly painted tanks (buckets noted, and reference to prior photos and site visit by Danielle Irwin reference notation of PE seal and fiberglass by Levi Sciara. (Holes and tears in plastic on battery from this vantage)

Photograph 59

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Proceeding toward SW corner

Frac tanks with tanker/frac loading line draped over berm (disconnected)

Photograph 60

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Looking toward NW corner

Photograph 61

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Pumping unit in background

Photograph 62

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Loading line (disconnected)

Photograph 63

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Close-up of loading line with check valve and side tap

Photograph 64

Time: 10:25 – 10:30 am

Location: West side of well pad - at center

Notes: Close-up of loading line with check valve and side tap

Photograph 65

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Noted no secondary containment for chemical tote.

Photograph 66

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Noted no secondary containment for chemical tote.

Photograph 67

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Noted 7 barrels on pallets with no secondary containment

Photograph 68

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Noted no secondary containment for chemical tote.

Photograph 69

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Noted no secondary containment for chemical tote or barrels.

Photograph 70

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: 7 frac tanks foreground and 1 off well pad.

Photograph 71

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: 7 frac tanks foreground and 1 off well pad.

Monitoring well on SW corner of well pad installed per direction of FDEP (monitoring wells on all four corners of site)

Photograph 72

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: 7 frac tanks foreground and 1 off well pad.

Monitoring well on SW corner of well pad installed per direction of FDEP (monitoring wells on all four corners of site)

Photograph 73

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Looking west in front of proposed DMW location.

Photograph 74

Time: 10:25 – 10:30 am

Location: South side of well pad

Notes: Agricultural water drainage/supply/storage next to entrance road.

Photograph 75

Time: 10:25 – 10:30 am

Location: South side of well pad.

Notes: Agricultural water drainage/supply/storage next to entrance road. Also boom constructed in ditch adjacent and south of well pad entrance grade to location. Site personnel noting boom installation.

Photograph 76

Time: 10:25 – 10:30 am

Location: South side of well pad

Notes: Toward exit road

Photograph 77

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: 7 frac tanks foreground.

Photograph 78

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Second row of frac tanks foreground.

Photograph 79

Time: 10:25 – 10:30 am

Location: SW side of well pad

Notes: Offsite frac tank with Levi foreground.

Photograph 80

Time: 10:25 – 10:30 am

Location: South side of well pad

Notes: Agricultural water drainage/storage next to entrance road.

Photograph 81

Time: 10:25 – 10:30 am

Location: South side of well pad

Notes: Agricultural water drainage/supply/storage next to entrance road. Also note boom constructed in ditch adjacent and south of well pad entrance grade to location.

Photograph 82

Time: 10:25 – 10:30 am

Location: South side of well pad

Notes: Agricultural water drainage/supply/storage next to entrance road. Also note boom constructed in ditch adjacent and south of well pad entrance grade to location.

Photograph 83

Time: 11:00 am

Location: SW Corner DMW location.

Notes: Start to stake new Deep Monitoring Well (DMW) location.

Photograph 84

Time: 11:00 – 11:30 am

Location: SW Corner DMW location.

Notes: Start to stake new Deep Monitoring Well (DMW) location.

Photograph 85

Time: 11:00 – 11:30 am

Location: SW Corner DMW location.

Notes: Start to stake new Deep Monitoring Well (DMW) location.

Photograph 86

Time: 11:00 – 11:30 am

Location: South side of DMW location

Notes: Setback from location road stake.

Photograph 87

Time: 11:00 – 11:30 am

Location: South side of DMW location

Notes: Setback from location road stake.

Photograph 88

Time: 11:00 – 11:30 am

Location: South side of DMW location

Notes: Setback from location road stake.

Photograph 89

Time: 11:00 – 11:30 am

Location: SE corner stake

Photograph 90

Time: 11:00 – 11:30 am

Location: SE Corner with slit fence and sock install

Notes: Looking west

Photograph 91

Time: 11:00 – 11:30 am

Location: SE corner stake (silt fence and sock)

Notes: Looking east

Photograph 92

Time: 11:00 – 11:30 am

Location: SW corner stake (silt fence and sock)

Photograph 93

Time: 11:00 – 11:30 am

Location: SW corner stake (silt fence and sock)

Photograph 94

Time: 11:00 – 11:30am

Location: NW corner stake (silt fence and sock)

Notes: From south

Photograph 95

Time: 11:00 – 11:30 am

Location: NW corner stake (silt fence and sock)

Notes: From east

Photograph 96

Time: 11:00 – 11:30 am

Location: NE corner stake (silt fence and sock)

Notes: From east

Photograph 97

Time: 11:00 – 11:30 am

Location: NE corner

Notes: Stake (silt fence and sock) - from south

APPENDIX C
Potential Migration Pathways and Other Supporting Figures

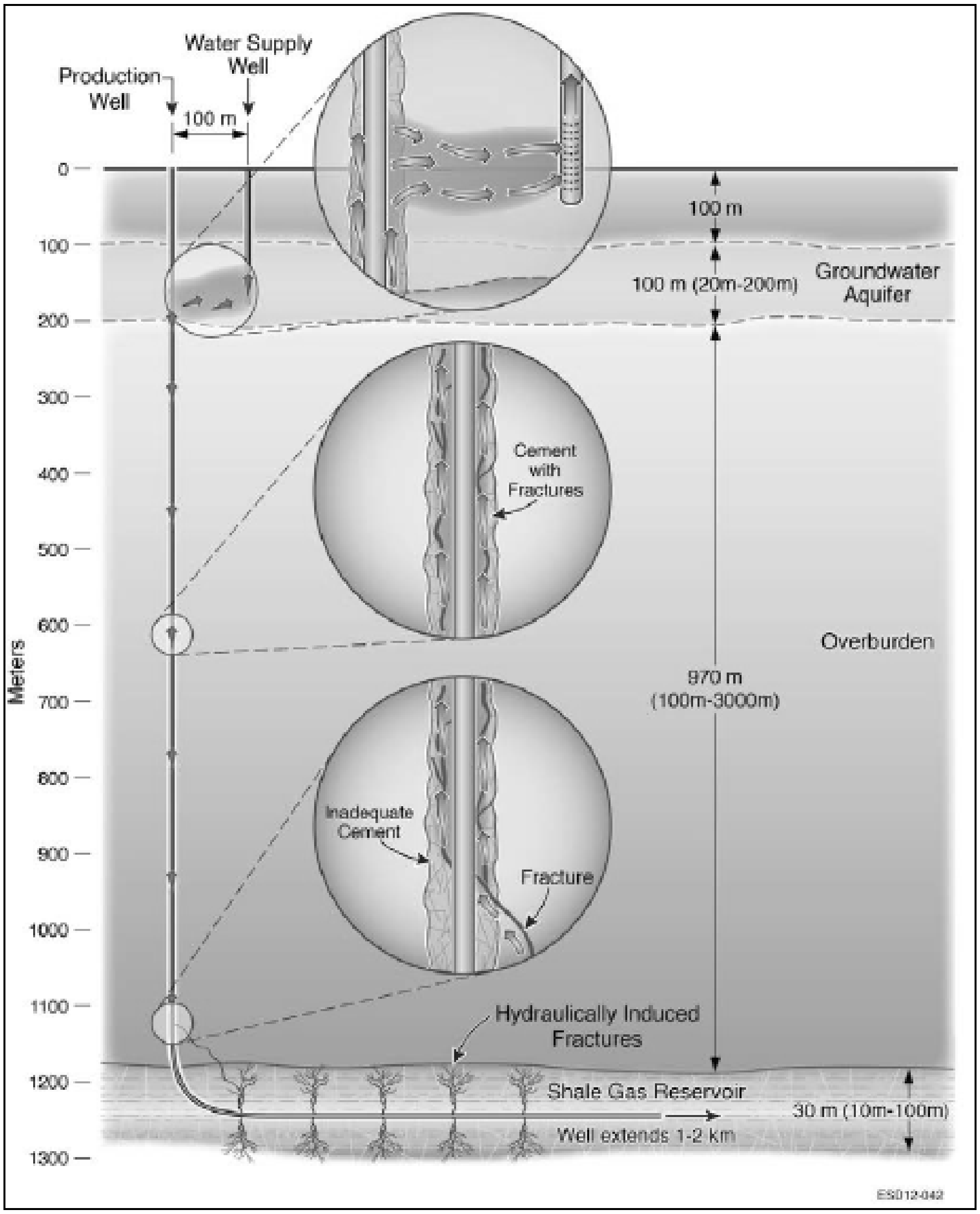

Figure C-1: Vertical Migration through Defective or Deficient Well Construction in the Well That Is Being Fractured

Source: U.S. Environmental Protection Agency (EPA), Office of Research and Development, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, Progress Report*, EPA 601/R-12/011 (December 2012), Figure 14, http://www2.epa.gov/sites/production/files/documents/hf-report20121214.pdf (accessed November 14, 2012).

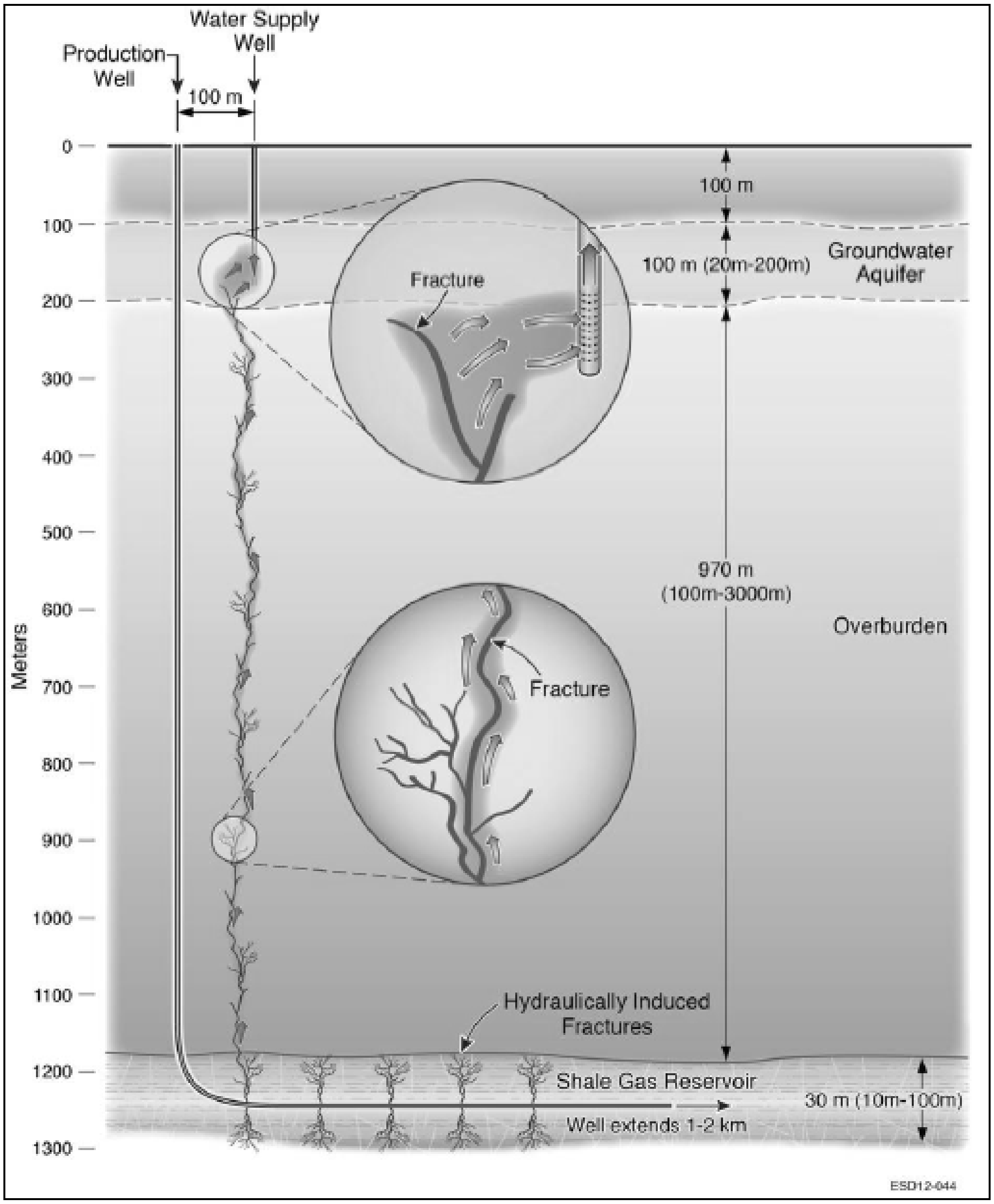

Figure C-2: Vertical Migration through Induced Fractures Created by Hydraulic Fracturing

Source: U.S. Environmental Protection Agency (EPA), Office of Research and Development, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, Progress Report*, EPA 601/R-12/011 (December 2012), Figure 15, http://www2.epa.gov/sites/production/files/documents/hf-report20121214.pdf (accessed November 14, 2012).

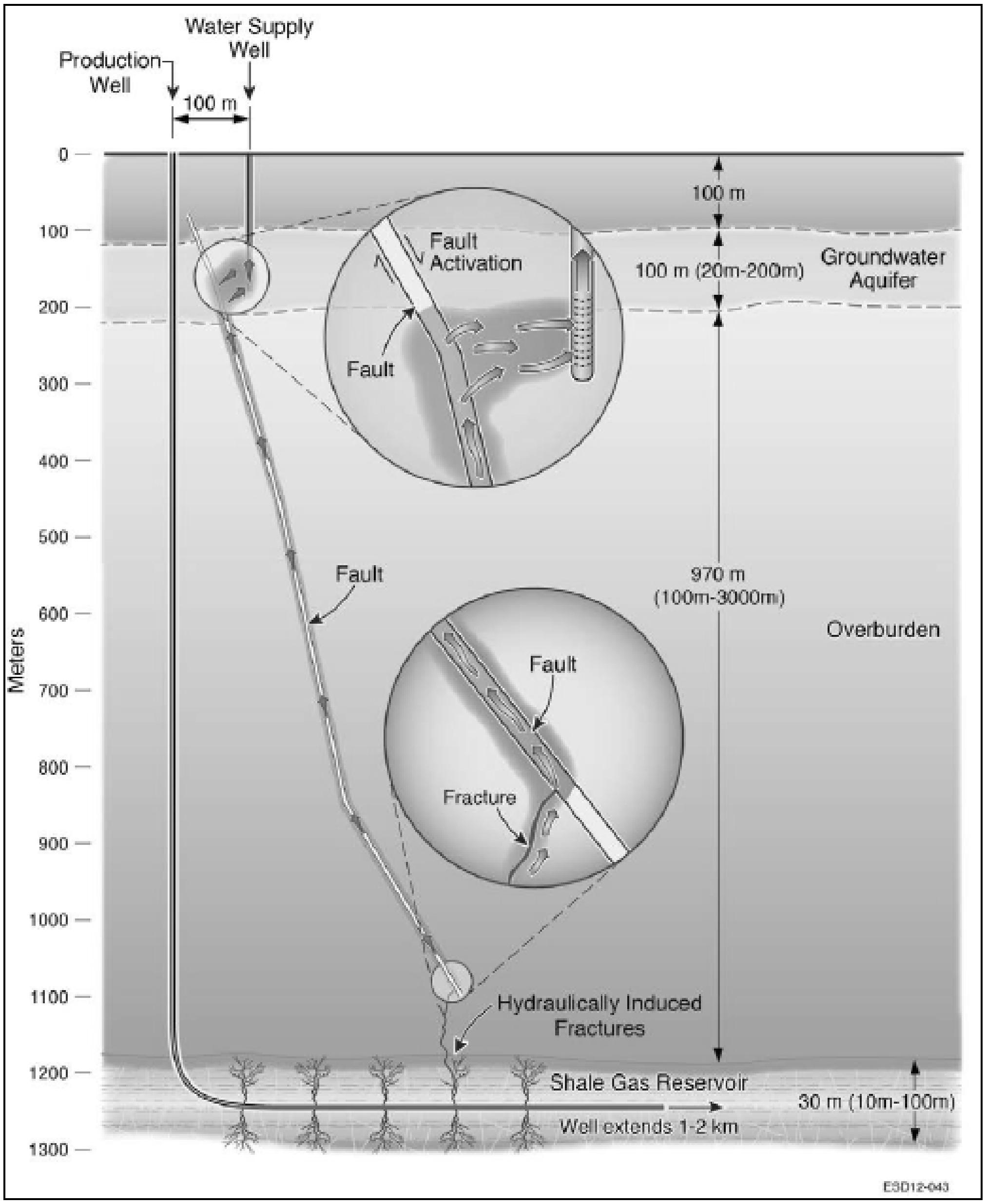

Figure C-3: Vertical Migration through Normally Salad Fractures That Have Been Activated by Hydraulic Fracturing

Source: U.S. Environmental Protection Agency (EPA), Office of Research and Development, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, Progress Report,* EPA 601/R-12/011 (December 2012), Figure 17, http://www2.epa.gov/sites/production/files/documents/hf-report20121214.pdf (accessed November 14, 2012).

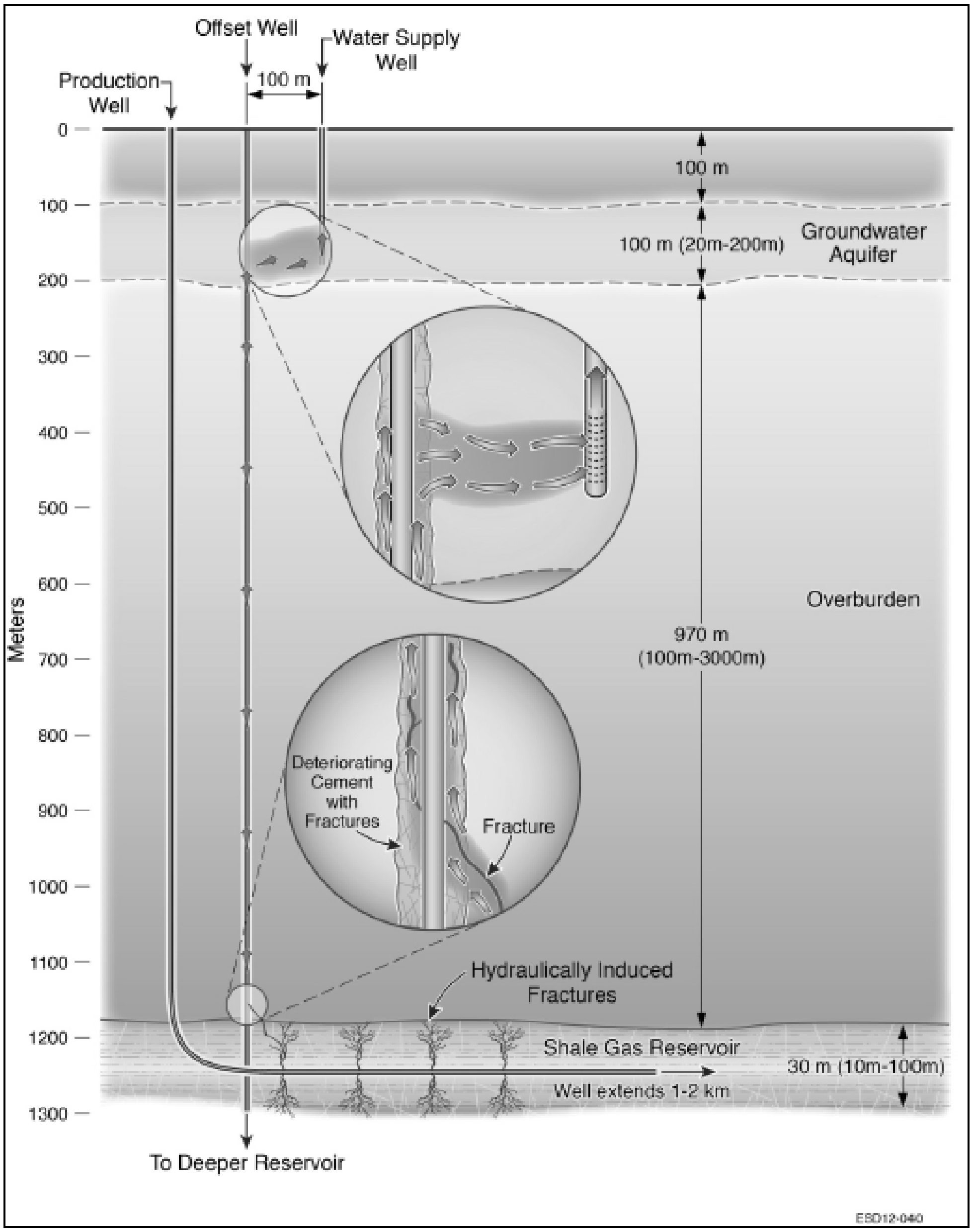

Figure C-4: Vertical Migration through Communication with an Off-set Well Having Deteriorating Casing Cement

Source: U.S. Environmental Protection Agency (EPA), Office of Research and Development, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, Progress Report*, EPA 601/R-12/011 (December 2012), Figure 18, http://www2.epa.gov/sites/production/files/documents/hf-report20121214.pdf (accessed November 14, 2012).

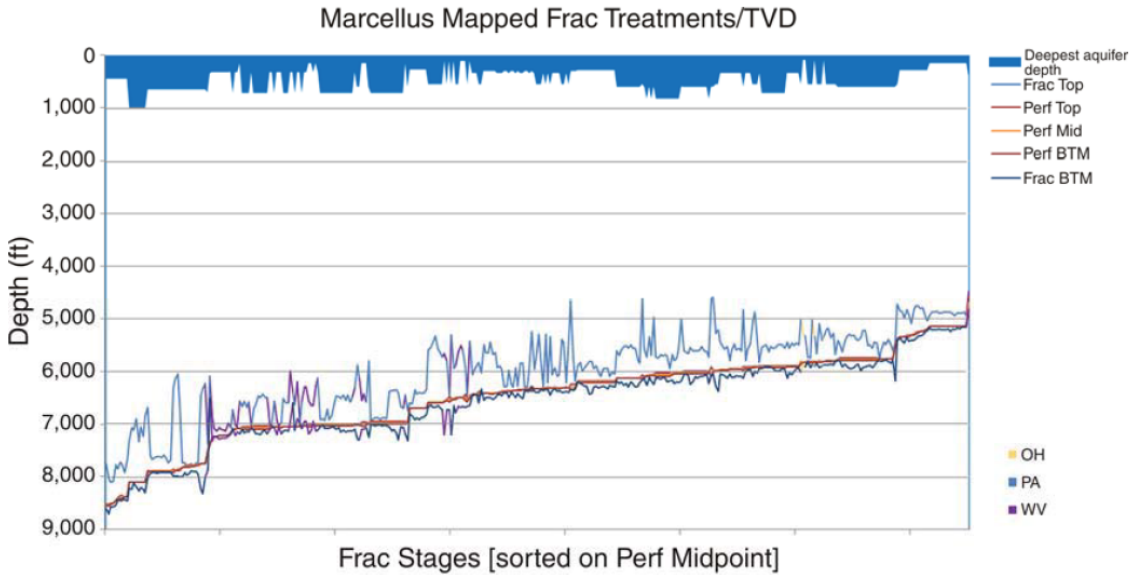

Figure C-5: Comparison of Maximum Fresh Groundwater Depth to Maximum Induced Fracture Height in Marcellus Shale Fracture Stimulations

Source: Kevin Fisher and Norm Warpinski, "Hydraulic Fracture-Height Growth: Real Data," SPE 145949, presented at the Society of Petroleum Engineers Annual Technical Conference, Denver, CO, October 30-November 2, 2011.

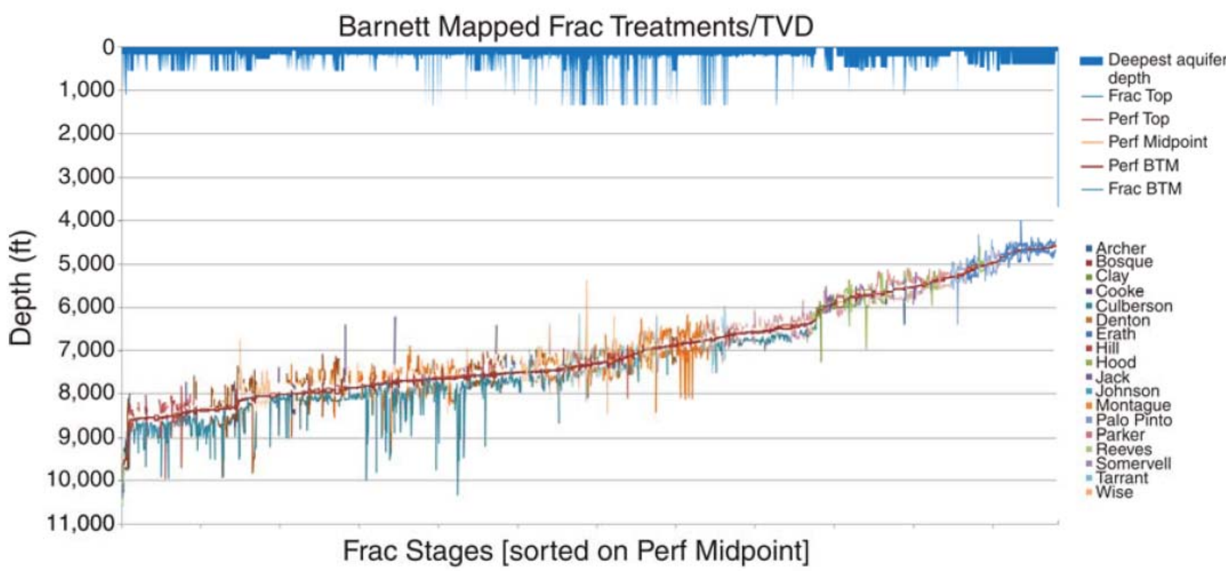

Figure C-6 – Comparison of Maximum Fresh Groundwater Depth to Maximum Induced Fracture Height in Barnett Shale Fracture Stimulations

Source: Kevin Fisher and Norm Warpinski, "Hydraulic Fracture-Height Growth: Real Data," SPE 145949, presented at the Society of Petroleum Engineers Annual Technical Conference, Denver, CO, October 30-November 2, 2011.

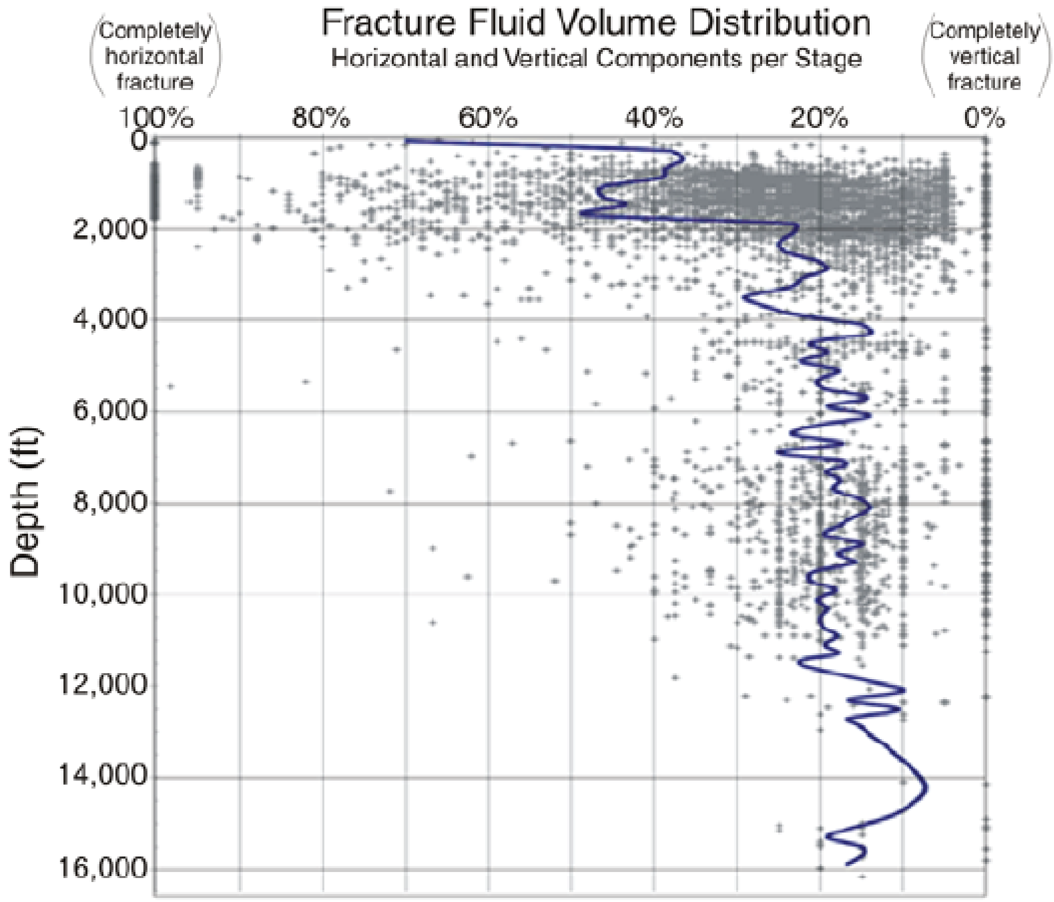

Figure C-7: Horizontal v. Vertical Fracture Growth with Depth

Source: Kevin Fisher and Norm Warpinski, "Hydraulic Fracture-Height Growth: Real Data," SPE 145949, presented at the Society of Petroleum Engineers Annual Technical Conference, Denver, CO, October 30-November 2, 2011.