Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

Feasibility Study

Final Report

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Oklahoma Water Resources Board

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Executive Summary

Large volumes of produced[1] wastewater are generated in the oil and gas industry in Oklahoma. Currently, most of the produced water is managed by disposing of it using a practice known as underground injection, where that water can no longer be accessed or used. As a result, this Potential Impacts of Select Alternative Produced Water Management and Reuse Scenario Potential Impacts Feasibility Study (Study) was conducted under a grant from the United States Department of Interior Bureau of Reclamation (Reclamation) through the Title XVI Water Reclamation and Reuse Program to the Oklahoma Water Resources Board to assess beneficial uses for the state's excess produced water as the current practice of deep disposal of the produced water has been associated with recent seismic events (Office of the Oklahoma Secretary of Energy and Environment 2019). Use of produced water would provide additional flexibility for producers, opportunities to address water scarcity concerns and would reduce underground injection. This Study focuses on produced water availability and demand in two main oil and gas production areas of Mississippi Lime and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (STACK).

The goal of this Study evaluated two produced water management alternatives in oil and gas operations in oil and gas operations in Oklahoma. The scope of this Study was as follows:

- Engage stakeholders and industry to understand produced water management and where the alternatives fit.
- Evaluate costs of the selected produced water management alternatives.
- Evaluate environmental considerations and impacts.

This Study took a deeper look at the two alternatives to deep well disposal presented in the *Report of the Oklahoma Produced Water Working Group* (PWWG Report) (CH2M 2017) that made the most economic sense and fit the Reclamation's Title XVI Program criteria for an economically and environmentally sound water project: (1) transfer of excess produced water from the Mississippi Lime production area to the STACK play through a pipeline, and (2) evaporation of excess produced water in the Mississippi Lime area. Oil and gas operators in the Mississippi Lime have traditionally depended on reuse of produced water to meet water demands for production; however, excess volume must be injected into disposal wells. Operators in the STACK have traditionally relied solely on freshwater sources to meet water demands.

Two scenarios using different amounts of produced water, 200,000 and 400,000 barrels per day (bpd), were considered for the option of transferring produced water through a pipeline. In both scenarios, it was assumed that new infrastructure would be implemented to gather, convey, store, and pump the water from the Mississippi Lime to the STACK. Conceptual level costs were prepared for each scenario and compared to the costs of disposing of produced water in the Mississippi Lime and sourcing freshwater in the STACK.

The produced water evaporation alternative was considered using five distinct types of evaporation technologies. Each was evaluated for the following:

1) Water recovery: Rate and amount of production of reusable water or water evaporation
2) Mobility: Requirements for transporting the water to a wastewater treatment facility
3) Air quality impacts: Byproducts of evaporation
4) Primary energy source: Electrical requirements to operate mechanical components
5) Energy demand: Relative energy demands (high, medium, or low) for each technology
6) Waste products and disposal: Residual waste produced, including concentrated brine and crystallized salt cake, which may require deep well injection or landfilling (which requires a permit)

[1] Produced water- For purposes of this study, the report uses the definition of *produced water* found at 40 Code of Federal Regulations Part 435 which is: "the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process."

Table ES-1 summarizes the evaluation of the alternatives, with the following conclusions:

- **Transfer of 200,000 or 400,000 bpd**: These options both would reduce freshwater use and produced water injection in the Study area. Water transfer would augment, not fully replace, the oil and gas producers' freshwater supply in the STACK production area. Water transfer would reduce the rate of produced water injection in the Mississippi Lime production area. However, current 2019 economic and operational circumstances would make a transfer pipeline infeasible at this time. The capital and operating costs (including water treatment), would exceed the current water sourcing and produced water disposal costs for both the Mississippi and STACK producers. The Study estimated that the produced water transfer and treatment of 400,000 bpd (including capital depreciation), was approximately $0.93 per barrel. The current source water costs of freshwater are approximately $0.50 per barrel in STACK. In addition, potential investors may perceive risks associated with long-term operational contractual commitments needed between water users and owners and operators of the produced water transfer infrastructure. Also, the operators in the STACK have expressed potential concerns over the water quality differences between Mississippi Lime and STACK areas that may impact STACK producers' operations.

  Water transfer could become a more feasible option if the current produced water sourcing and disposal operational conditions changed: for example, if the disposal costs increase in the Mississippi Lime area, if there is an increase in oil and gas market prices that would increase oil and gas production, or if source water costs in the STACK increase due to a major drought.

  Further studies are needed to bridge the knowledge gap associated with produced water quality to reduce potential human health and ecological risks due to spills or leaks. In addition to data gaps for produced water composition and potential toxicity, there are information gaps on produced water generation volumes and locations and matching those with potential produced water demands.

- **Evaporation**: all five different evaporation technology types evaluated would reduce produced water disposal by injection but not reduce freshwater use in oil and gas operations in the Study area[2]. Water recovery associated with a type of an evaporation technology (Modular Thermal Evaporator with Water Recovery) would be minimal and would not augment water supply for oil and gas operations. Capital costs are highly variable and dependent on project location. Also, the costs (both capital and operations and maintenance [O&M]) vary according to the technology. Those technologies capable of treating large volumes of variable types of water chemistry makeup and high total dissolved solids (TDS) require use of chemicals, monitoring, and highly skilled labor; they also tend to have high energy consumption, increasing the O&M costs. Further studies are needed to minimize potential human health and ecological risks caused by reuse of treatment residuals or recovered by-product water.

Neither of the alternatives—pipeline transfer or evaporation—considered in this Study to reduce freshwater use in oil and gas operations or to reduce produced water disposal by injecting it to underground, or both, are currently feasible as proposed. However, if water sourcing costs increase significantly in the STACK area, the pipeline scenario could become viable; and if water disposal costs increase in Mississippi Lime area, evaporation alternatives would become economically competitive. Therefore, additional studies are recommended as conditions change. One of the key recommendations includes incentivization of the industry's participation as part of the solution. Many industry representatives indicated in the Industry Workshop that, as injection capacity decreases, or freshwater use is curtailed in the state, or both, alterative produced water management options would be needed. As next steps, the Study recommendation includes conducting a pilot study to model different "what-if"-scenarios to yield different projections for produced water management based on the following: changing the key inputs, such as water quality parameters (treatment needs); life-cycle costs; oil and gas prices (economic conditions); types of contract mechanisms between producers and third-party investors; produced water supply and demand; or freshwater availability and disposal feasibility, for example. This scenario planning would allow the industry, potential investors, and regulators to identify situations that can incentivize or impede produced water reuse in the oil and gas industry.

Table ES-1 provides information on the evaluation of produced water management alternatives.

[2] Although the report delimits between manufacturer claims and peer-reviewed scientific data through the case studies, readers should be aware that, for some technologies and processes, manufacturer brochures were the only available source for information.

Table ES-1. Evaluation of Produced Water Management Alternatives

Alternative	Costs				Considerations and Risks	Implementation Opportunities and Future Considerations	Feasibility of Implementation	Reduces Freshwater Use, Produced Water Injection, or Both
	Total Capital (MM $)	Current Day Cost ($/BW)						
Oil and Gas Operator Water Sourcing and Disposal Costs (Current practice)								
Sourcing in the STACK and SCOOP[a]	-	0.5 [b,c]	-	-	-	-	-	-
Disposal in the Mississippi Lime[a]	-	0.06 to 0.20[d]	-	-	-	-	-	-
Water Transfer through a Pipeline Alternative								
Transfer of 200,000 bpd	329	1.21[e]			• Water quality compatibility unclear between Mississippi Lime and STACK • Piping and storage of large volumes of high TDS water • Financial uncertainty with fluctuating oil and gas prices • Upfront investment requirements • Long-term contracts needed between operators and investors • Environmental risks: spills and leaks of unknown chemistry of produced waters due to compounds used in operations and constituents naturally present in producing formations that are contained in the resulting produced water: potential toxicity and impacts on human health and ecological implications • Matching Mississippi Lime produced water supply with STACK area demand	Technical: • Conduct a pilot study to determine: – Water quality needs and compatibility – Scenario planning for produced water supply and demand Environmental: • Develop guidelines to: – Help select the best site-specific storage alternative between ASTs or in-ground impoundment (an engineered, lined pond) based on criteria that includes total volume, site layout, location with respect to floodplain or protected areas, depth to groundwater, distance to surface water, soil conditions, and other environmental criteria – Avoid and minimize spills and leaks with water transfer: high-quality pipeline, automation, and block valves to isolate the system, and leak detection systems for shut in – Verify analytical methods to monitor constituents in produced water Legal, Regulatory, and Permitting: • Coordinate the existing permitting through the state Department of Transportation, OCC, and Department of Environmental Quality • Determine ownership of produced water, especially if it becomes beneficial use Financial: • Conduct a pilot study to determine project lifecycle costs and “what if” scenarios to include price of oil and gas, disposal well shutdowns, and different levels of drought (lack of freshwater supplies) Stakeholder and Political: • Oil and gas industry engagement through PWWG to find fitting solutions • Existing state regulations/requirements need to be clarified with produced water management (e.g., water rights of treated produced water)	Current 2019 economic and operational circumstances make a transfer pipeline infeasible. This could change if disposal costs in the Mississippi Lime increase, if oil and gas market prices increase, or if a major drought complicates access to fresh water in the STACK area. Further studies are needed as conditions change. A transfer pipeline in another oil and gas production may be feasible sooner.	Both
Transfer of 400,000 bpd	462	0.93 [e]					Current 2019 economic and operational circumstances make a transfer pipeline infeasible. This could change if disposal costs in the Mississippi Lime increase, if oil and gas market prices increase, or if a major drought complicates access to freshwater in the STACK area. Further studies are needed as conditions change. A transfer pipeline in another oil and gas production may be feasible sooner.	Both

Table ES-1. Evaluation of Produced Water Management Alternatives

Alternative[a]	Evaporation					
	Cost	Estimated Development Schedule	Considerations and Risks	Implementation Opportunities and Future Considerations	Feasibility of Implementation	Reduces Freshwater Use or Produced Water Injection or Both
Evaporation Pond	Capital costs are highly variable and dependent on location. There is little economy of scale, and method is most competitive for small flows where disposal costs are very high. Can be low cost, if existing pond is available. O&M costs: • Relative energy demands are low: only energy requirement is pumping of concentrate to the pond: mechanical equipment used in pumps • Limited need for labor • Liner repairs and monitoring • Offsite sludge disposal costs	New evaporation ponds can take months to permit and construct.	Dredged solids disposal to landfill No chemicals required Large land area requirements Landscape and topography are important in siting the location of an evaporation pond Environmental risks: • Management of treatment residuals, particularly the salts and radioactive material: by-product disposal and use • Siting, designing, and constructing the ponds should consider minimizing the volume of water that is able to enter the pond from natural runoff or flooding	Technical: • More viable in relatively warm, dry climates with high evaporation rates, level terrain • Suited for smaller volumes of produced water (less than 500,000 bbls per year) Environmental: • Determine safe use for evaporation by-product • Identify any concentrations of toxic trace elements in by-products Legal, Regulatory, and Permitting: • State's oil and gas regulatory (OCC) has regulatory authority • Potential waste products could be sold: brine, salt cake: determine safe use and regulatory authority Financial: • Offside sludge disposal can be expensive • Cost effective where land costs low • More economical and competitive to small flows.	Feasible now for small volumes of produced water when nearby disposal is unavailable. Evaporation ponds are being used in the Powder River Basin	Reduces injection only
Enhanced Evaporation (Evaporation Pond with Mechanical Spray)	Capital costs are highly variable and dependent on location. Can have lower costs than thermal evaporation. O&M costs: • Relative energy demands are low: energy requirements include pumping concentrate to the pond and use of mechanical spray • Limited need for skilled labor • Liner repairs and monitoring • Offsite sludge disposal costs	Permits, ponds, and facilities could take months, but faster if mobile facilities.	Dredged solids disposal to landfill Chemicals required for pretreatment Land area requirements may be less than in large evaporation ponds (above) Landscape and topography are important in siting the location of an evaporation pond Environmental risks: • Over spray and mist drifting can cause soil and vegetation contamination • Management of treatment residuals, particularly the salts and radioactive material: by-product disposal and use • Siting, designing, and constructing the ponds should consider minimizing the volume of water that is able to enter the pond from natural runoff or flooding	Technical: • More viable in relatively warm, dry climates with high evaporation rates, level terrain • Suited for smaller volumes (approximately 10,00 bwpd) Environmental: • Determine safe use for evaporation by-product • Identify any concentrations of toxic trace elements in by-products • Soils testing to control overspray and misting Legal, Regulatory, and Permitting: • State's oil and gas regulatory (OCC) has regulatory authority • Potential waste products could be sold: brine, salt cake: determine safe use and regulatory authority Financial: • Offside sludge disposal can be expensive • Cost effective where land costs low • More economical and competitive to small flows	Technically feasible now, but economic challenges remain for use in Oklahoma. The only enhanced evaporation project in Oklahoma was suspended recently. Total costs are likely twice or more the cost of disposal.	Reduces injection only
Modular Thermal Evaporator Vented to the Atmosphere	Capital costs are highly variable and dependent on location. O&M costs: • Relative energy demands are high due to boiling of the produced water • High level of skilled labor required: high levels of monitoring and control	Permits, ponds, and facilities could take months, but faster if mobile facilities.	Use of some chemicals required: scale inhibitor and acid may be required for process control to prevent scaling Environmental risks: • Management of treatment residuals, particularly the salts and radioactive material: by-product disposal and use	Technical: • More viable in relatively warm, dry climates with high evaporation rates, level terrain • Modular unit's treatment capacity may range from 5,000 to 20,000 bwpd and multiple units can be employed at a single location if sufficient energy is available • High level of flexibility: easy to adapt to highly varying water quality and quantity Environmental: • Determine safe use for evaporation by-product • Identify any concentrations of toxic trace elements in by-products • Soils testing to prevent overspray and misting Legal, Regulatory, and Permitting: • State's oil and gas regulatory (OCC) has regulatory authority • Potential waste products could be sold: brine, salt cake: determine safe use and regulatory authority	Technically feasible now, but economic challenges remain Current technology has high costs compared to current disposal costs. Costs are also higher for high TDS water due to solids hauling and disposal.	Reduces injection and water recovered for potential reuse

Table ES-1. Evaluation of Produced Water Management Alternatives

Alternative[a]	Evaporation					
	Cost	Estimated Development Schedule	Considerations and Risks	Implementation Opportunities and Future Considerations	Feasibility of Implementation	Reduces Freshwater Use or Produced Water Injection or Both
Modular Thermal Evaporator with Water Recovery	Costs for water recovery are higher than venting water vapor. O&M costs: • High level of skilled labor required: high levels of monitoring and control • Relative energy demands are high due to boiling of the produced water	Ponds and facilities could take months, but faster if mobile facilities. Permits for discharge have historically taken 1 to 2 years.	Use of chemicals required: scale inhibitor and acid may be required for process control to prevent scaling Product water quality is high, with little variation due to feed or concentrate salt content Environmental risks: • Management of treatment residuals, particularly the salts and radioactive material: by-product disposal and use • Recovered water safe re-use and discharge to water bodies	Technical: • High level of flexibility: easy to adapt to highly varying water quality and quantity • Applicable to a wide TDS range (<100,000 mg/L TDS), and all types of water chemistry makeup Environmental: • Recovered water quality monitoring Legal, Regulatory, and Permitting: • State's oil and gas regulatory (OCC) has regulatory authority • Determine regulatory authority for byproduct water use and potential waste products that could be sold: brine, salt cake • Determine recovered water reuse safety standards for human consumption and ecological use; monitoring and discharge to water bodies	Technically feasible now, but economic challenges remain. If 25,000 TDS produced water (typical for central OK) is concentrated to 250,000 TDS, the process would yield 90% freshwater and 10% concentrate for disposal.	Reduces injection only (potentially reduces injection by up to 90%)
Traditional Thermal Evaporator and Crystallizer with Water Recovery	Highest cost option, especially due to the additional solids handling requirements. O&M costs: • Relative energy demands are high • High level of skilled labor required: high levels of monitoring and control	Permits, ponds, and facilities could take months, but faster if mobile facilities. Permits for discharge have historically taken 1 to 2 years.	Environmental risks: • Management of treatment residuals, particularly the salts and radioactive material: by-product disposal and use • Recovered water safe re-use and discharge to water bodies	Technical • Suited for high concentrate TDS flows and large flow rates (50,000+ bwpd for centralized plant) Environmental: • Recovered water quality monitoring Legal, Regulatory, and Permitting: • State's oil and gas regulatory (OCC) has regulatory authority • Determine regulatory authority for byproduct water use and potential waste products that could be sold: brine, salt cake • Determine recovered water reuse safety standards for human consumption and ecological use; monitoring and discharge to water bodies	Technically feasible now, but economic challenges remain. Long term commitments from producer needed to secure financing for plant that can cost $MM 200+ in capital.	Reduces injection and water recovered for potential reuse

[a] Although the report delimits between manufacturer claims and peer-reviewed scientific data through the case studies, the readers should be aware that, for some technologies/processes, manufacturer brochures were the only available source for information.

[b] Costs reported by operators during Produced Water Transfer Workshop in January 2017.

[c] An additional $1.00 to $3.00 required if water is trucked.

[d] $1.09 per bwpd for sourcing and disposal as reported by operators, with $0.5 for sourcing.

[e] Costs represent disposal to operator-owned saltwater disposal wells.

[f] Includes also water treatment, pumping, and maintenance (200,000 bpd: $0.52/barrel and 400,000 bpd: $0.45).

Notes:

$/BW = dollars per barrel of water
- = not applicable
< = less than
AST = aboveground storage tank
bbls = barrel(s)
bwpd = barrels of water per day
mg/L = milligrams per liter
MM$ = million of dollars
OCC = Oklahoma Corporation Commission
PWWG = Produced Water Working Group
SCOOP = South Central Oklahoma Oil Province

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Acronyms and Abbreviations

AF	acre-foot (feet)
bbls	barrel(s)
BEG	University of Texas Bureau of Economic Geology
bpd	barrel(s) per day
BTEX	benzene, toluene, ethylbenzene, and xylenes
bwpd	barrel(s) of water per day
CDC	Centers for Disease Control
CFR	Code of Federal Regulations
CH2M	CH2M HILL, Inc.
CWA	Clean Water Act
DAF	dissolved air filtration
DRO	diesel-range organics
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
fps	foot (feet) per second
GRO	gasoline-range organics
GWPC	Groundwater Protection Council
H_2S	hydrogen sulfide
HDPE	high-density polyethylene
Jacobs	Jacobs Engineering Group Inc.
MDL	method detection limit
mg/L	milligram(s) per liter
mph	mile(s) per hour
MVC	mechanical vapor compression
NG	natural gas
NIMBY	not in my backyard; a person who objects to the siting of something perceived as unpleasant or potentially dangerous in their own neighborhood
NORM	naturally occurring radioactive material
O&M	operations and maintenance
OAC	Oklahoma Administrative Code
OCC	Oklahoma Corporation Commission
ODEQ	Oklahoma Department of Environmental Quality
ODOT	Oklahoma Department of Transportation
OWRB	Oklahoma Water Resources Board
pCi/L	picocurie(s) per liter
PHC	petroleum hydrocarbon

ppm	part(s) per million
PT	provisional temporary
PWWG Report	Report of the Oklahoma Produced Water Working Group
PWWG	Produced Water Working Group
RCRA	*Resource Conservation and Recovery Act*
Reclamation	U.S. Department of Interior, Bureau of Reclamation
RO	reverse osmosis
ROW	right-of-way
SCOOP	South Central Oklahoma Oil Province
SRB	sulfate-reducing bacteria
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties
Study	Alternative Produced Water Management and Reuse Feasibility Study
sVOC	semivolatile organic compound
SWD	saltwater disposal well
TBD	to be determined
TDS	total dissolved solids
TSS	total suspended solids
U.S.	United States
USACE	U.S. Army Corps Engineers
VOC	volatile organic compound
WWTP	wastewater treatment plant

1. Introduction and Background

This Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios Feasibility Study (Study) was conducted by was conducted under a grant from the United States Department of Interior Bureau of Reclamation (Reclamation) through the Title XVI Water Reclamation and Reuse Program to the Oklahoma Water Resources Board (OWRB) to assess beneficial uses for the state's excess produced water. Use of produced water from oil and gas operations would provide additional flexibility for producers, opportunities to address water scarcity concerns and to reduce disposal by underground injection that has been associated with recent seismic events in Oklahoma (Office of the Oklahoma Secretary of Energy and Environment 2019).

The OWRB commissioned CH2M HILL, Inc. (CH2M), now a Jacobs Engineering Group Inc. (Jacobs) Company, to evaluate two produced water management alternatives in oil and gas operations in Oklahoma. The two alternatives included the reuse of produced water in oil and gas operations and evaporation of produced water in lieu of deep well injection.

This study focuses on produced water in two main oil and gas production areas of Mississippi Lime and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (STACK).

Managing freshwater supplies should include a portfolio of innovative new water sources to meet increasing water demands. Balancing water use needs and produced water disposal requirements associated with oil and gas development create significant challenges to both the oil and gas industry and regulators in Oklahoma. Reuse of produced water has the potential to meet some of these challenges by replacing or supplementing freshwater in hydraulic fracturing operations. Additionally, produced water reuse can potentially reduce the risks of earthquakes caused by high injection volumes to saltwater disposal wells (SWDs).

This Study focuses and builds upon the two key recommendations of the *Report of the Oklahoma Produced Water Working Group* (PWWG Report) (CH2M 2017) to: (1) take a more in-depth look at the feasibility of produced water transfer from the Mississippi Lime production area (Alfalfa and Wood Counties) to the STACK production area, and (2) determine the viability of produced water evaporation as an alternative to disposal by injection. As such, this Study supports the State of Oklahoma's water conservation goals and the oil and gas industry's role in advancing the dialogue to investigate different approaches to reducing and recycling produced water in oil and gas operations.

In 2015, Oklahoma Governor Mary Fallin launched an initiative to explore ways to reuse and recycle water produced in oil and gas operations[3] in support of the goal of the Water for 2060 Act[4] to conserve freshwater in Oklahoma. To achieve this goal, a 17-member Produced Water Working Group (PWWG), led by the OWRB, was tasked with studying and recommending alternatives to produced water disposal from oil and gas operations in Oklahoma. The PWWG's effort and recommendations are summarized in the PWWG Report. The PWWG Report assessed the potential alternatives to current practices of injecting produced water from oil and gas wells into disposal wells in Oklahoma.

Ten representative cases were assessed by the PWWG to prioritize and make recommendations for further study. Each case involved coupling a potential produced water user or alternative disposal method to an existing adjoining produced water source and evaluating the economic outcome.

The PWWG Report concluded that produced water reuse by the oil and gas industry is the most cost-effective beneficial use alternative due to minimal water treatment needs. To effectively implement reuse, increased inter-organizational planning between the state's regulatory and resource agencies and resource sharing would be required. The oil and gas industry has built limited water pipeline networks to

[3] 36th Annual Oklahoma Governor's Water Conference and Research Symposium in Norman, Oklahoma, Tuesday, December 1, 2015.

[4] With passage of House Bill 3055 (the Water For 2060 Act) in 2012, Oklahoma set a statewide goal of consuming no more freshwater in 2060 than was consumed in 2010.

date; however, the expansion of water distribution systems over time would further facilitate produced water reuse.

The PWWG Report also recommended further investigation of evaporation techniques for produced water. Due to low water treatment costs and potentially limited water conveyance requirements, evaporation technology was determined to be a viable alternative to SWDs.

1.1 Purpose and Objectives of the Study

To continue the efforts of the PWWG and deepen the understanding of water reuse opportunities in Oklahoma, the OWRB conducted this Study under a grant from Reclamation through the Title XVI Water Reclamation and Reuse Program[5]. The Study was conducted in collaboration with the following cost-share study partners (Study Team):

- Environmental Defense Fund (EDF)
- Groundwater Protection Council (GWPC)
- University of Texas Bureau of Economic Geology (BEG)

The scope of the study was as follows:

- Engage stakeholders and industry to understand produced water management and where the alternatives fit.
- Evaluate costs of the selected produced water management alternatives.
- Evaluate environmental considerations and impacts.

The Study Team focused their investigation on the technical, economic, and environmental feasibility of (1) the transfer of excess produced water from the state's Mississippi Lime to STACK production area for reuse in oil and gas operations and (2) the use of current evaporation technologies on a wide scale as a produced water management option in lieu of injecting the produced water. Either of these options could result in the oil and gas industry using less of the state's freshwater resources by creating additional usable water and/or reducing the amount of produced water injected into SWDs. While the Study is not intended to address induced seismicity in Oklahoma that has been linked to the disposal of produced water from oil and gas operations by deep well injection (Office of the Oklahoma Secretary of Energy and Environment, 2019), the benefits of reuse and alternative disposal methods may be extended to potentially reduced seismicity.

1.2 Organization of the Report

This report is organized as follows:

- Section 1: Project background and introduction, and purpose and objectives.
- Section 2: Description of the Study area and a summary of the general characteristics of produced water in Oklahoma, including production and disposal volumes, general produced water management by the oil and gas industry, and oil and gas production water demand and permitting.
- Section 3: General water quality analysis of produced water in Mississippi Lime and STACK production areas. A detailed analysis of the water quality sampling is included in Appendix B.
- Section 4: List of Study Partners and external stakeholders; results of two study planning workshops to identify key opportunities and concerns regarding produced water reuse alternatives; and summary of the concept of transferring excess produced water from the Mississippi Lime production area through a pipeline to the STACK production areas for hydraulic fracturing. The project concept was initially described in the PWWG Report and further refined with this Study to include pipeline

[5] WaterSMART: Development of Feasibility Studies under the Title XVI Water Reclamation and Reuse Program for Fiscal Year 2017 Funding Opportunity Announcement No. BOR-DO-17-F003.

alignment and associated infrastructure needs, costs, implementation considerations, implementation schedule, findings, and next steps.

- Section 5: Summary of the concept of evaporating excess produced water as an alternative to deep well injection, with an overview and comparison of evaporation technologies, implementation considerations, findings, and next steps.

2. Oklahoma Produced Water

2.1 Introduction

As defined at 40 *Code of Federal Regulations* (CFR) § 435.11(bb) produced water is:

> *"…water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process."*

This water is generated during both conventional and unconventional oil and gas production. The volume and quality of produced water varies based on the geochemistry of the producing formation, geographical location, production stage of the well, and type of hydrocarbon produced (oil, gas, or condensate).

Conventional formations typically have higher water production late in a well's life, while unconventional formations that are hydraulically fractured typically produce high rates of water in the initial months and decline over time. Figure 2-1 shows the typical water production curves for hydraulically fractured wells in various regions of the United States (U.S.).

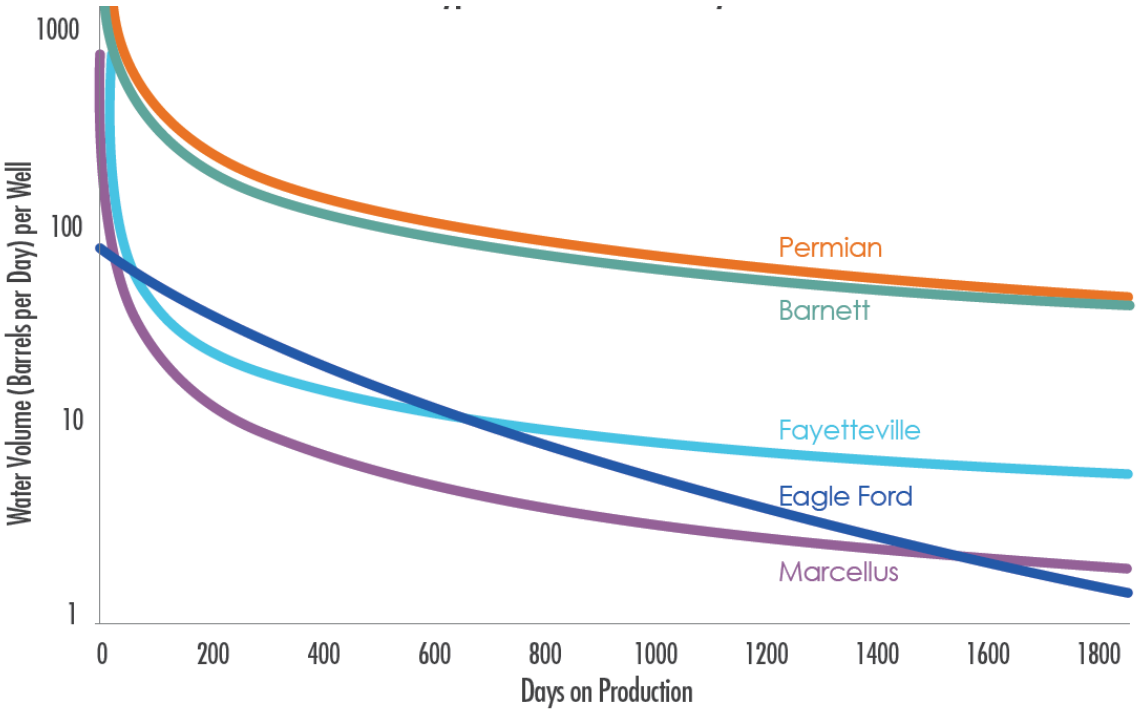


Figure 2-1. Typical Water Production by Oil Well
Source: the Energy Water Initiative

According to OCC estimates, in 2014, nearly 1.5 billion bbls of produced water were disposed underground by deep well injection in Oklahoma. In 2016, the underground injection of produced water was reduced due to OCC regulations in critical areas to limit the volume of injections that correlated with recent earthquakes in Oklahoma (Office of the Oklahoma Secretary of Energy and Environment, 2019).

Figure 2-2 shows the Oklahoma counties with the highest produced water disposal in 2017. Produced water is disposed in 66 counties in Oklahoma. As the figure shows, the top five counties for disposal are Alfalfa, Woods, Seminole, Creek, and Kay. These counties accounted for approximately half of Oklahoma's produced water disposal in 2017.

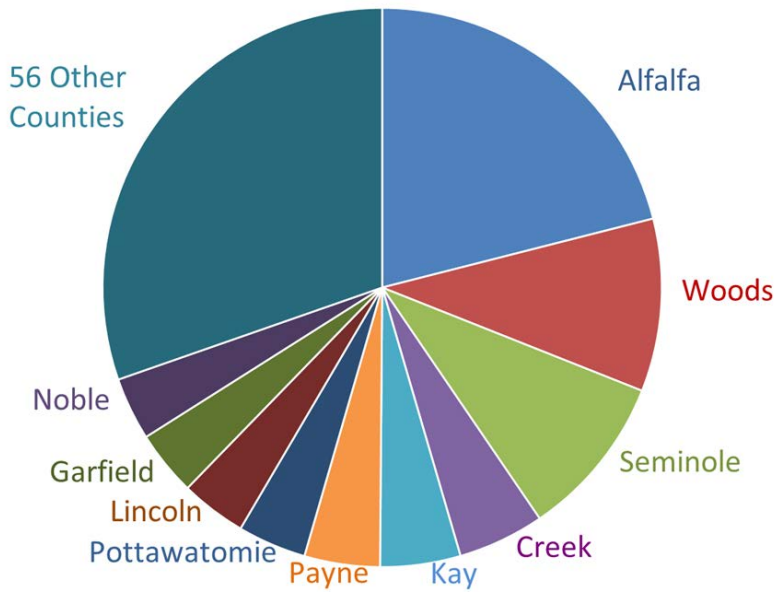


Figure 2-2. Oklahoma Produced Water Disposal by County in 2017
Source: the Energy Water Initiative

Figure 2-3 shows typical water uses and management in oil and gas production. Historically, freshwater has been the primary water source for oil and gas operations. Due to periodic droughts in Oklahoma, including the most recent 2011 to 2012 drought, freshwater use by oil and gas operations, municipal, and other industrial uses have elevated concerns of the state's water resources planners and local community leaders. To help alleviate these issues, several oil and gas hydraulic fracturing operations have been reusing produced water for drilling activities, which provides an added bonus of reducing deep well injection that may induce seismicity. Currently, most of these operations continue to dispose of produced water by injection.

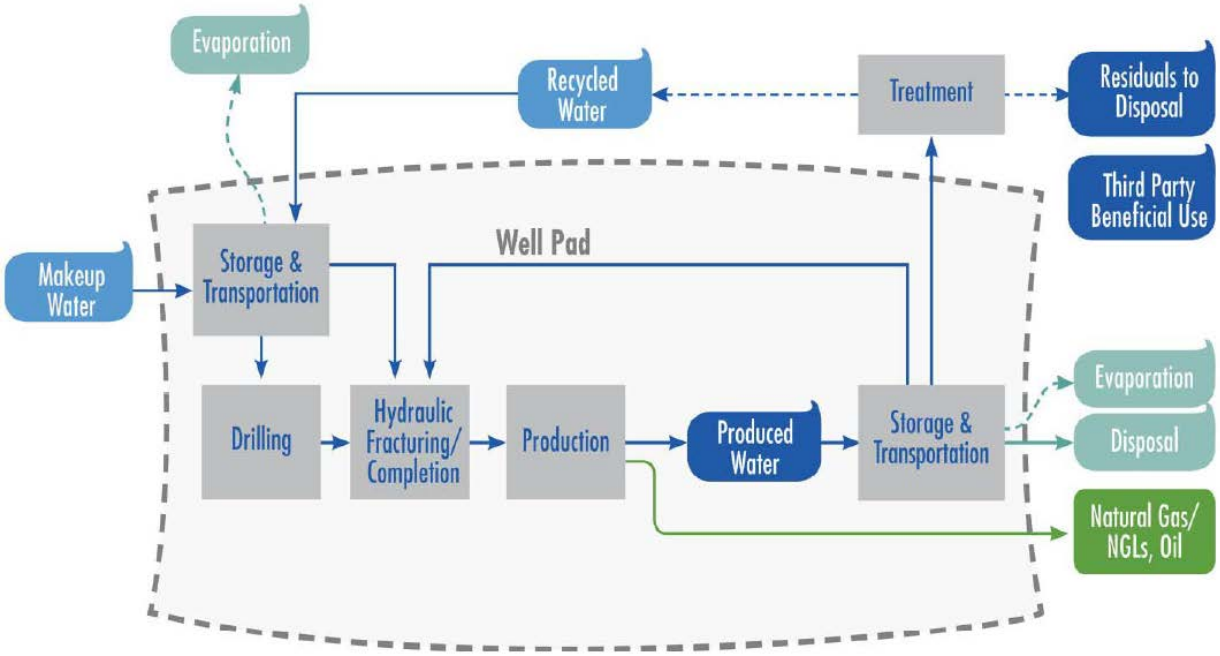


Figure 2-3. Typical Water Use and Management in Oil and Gas Production
Source: the Energy Water Initiative

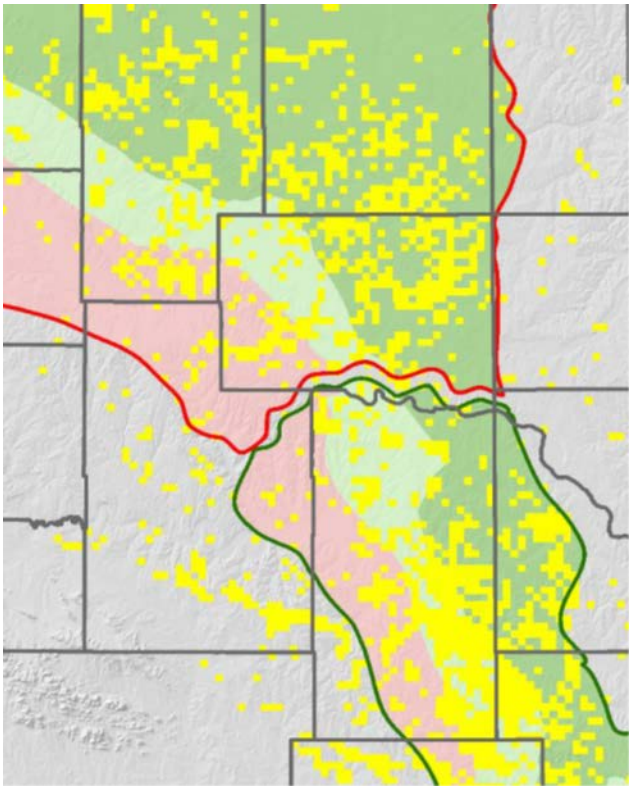
The challenges of produced water reuse in the oil and gas industry include both the adequate supply and compatibility of water quality for production. Another challenge is the transportation of produced water from the source to the point of use. Despite higher costs of trucking water and negative public perception due to potential environmental impacts (fugitive road dust, spills, and leaks) and public road use wear and tear, the majority of Oklahoma producers still rely on trucking freshwater to the site or trucking produced water to SWDs.

The PWWG Report determined that the average cost to source and dispose of produced water (water treatment and storage) in the STACK and SCOOP areas, without considering transportation, was $1.09/bbls[6]. The cost to truck water to another area for reuse may range from $1.00 to $3.00/bbls.

When produced water volumes are high, conveying produced water through a dedicated pipeline system becomes the best solution. The same pipeline system becomes a practical method for delivery to new production areas and facilitates reuse. Some of the existing reuse projects in Oklahoma (for example, Continental Resources and Newfield Exploration investor presentations) already use water pipelines and other infrastructure to transfer water to their operations.

The economic challenges to more widespread produced water use and transfer in the oil and gas industry are caused by the inherent nature of oil and gas production: operations are located in mostly rural areas with limited access to infrastructure (e.g., roads, electricity, and permanent water infrastructure), and a single operator may have operations spread across large tracts of land, thereby making it challenging for the industry to invest in permanent and centralized water infrastructure and to recover costs associated with water transfers. Additionally, in Oklahoma, most oil and gas companies do not own mineral rights in large, contiguous areas of land or surface rights, thereby limiting the ability to construct water transfer infrastructure for their water needs. To illustrate this, Figure 2-4 depicts a single Oklahoma-based oil and gas operator's production areas in central Oklahoma counties. A single operator's operations are spread across over a dozen counties and over large areas. If a single producer was to have more concentrated operations, water reuse could be aggregated by the producer; this would make reuse more economical due to more optimal pipeline layout, centralized water storage, and more efficient O&M.

[6] In a workshop as part of this Study, producing companies validated that the $1.09/bbls still seemed valid for 2018.



single producer's oil and gas production areas

Figure 2-4. An Example of Single Producers' Spread Operations across Multiple Central Oklahoma Counties

2.2 Mississippi Lime and STACK Production Areas

The Study areas were selected based on the recommendations of the PWWG Report to transfer excess produced water from the state's Mississippi Lime production area to STACK production area for reuse in oil and gas operations (Case 3 of the PWWG Report: Inter-county Clean Brine Transfer and Treatment). The two production areas were selected based on their imbalances between water demand and supply.

While oil and gas development is spread throughout Oklahoma, most of the current activity has been in the central part of the state in the STACK area spanning, from Blaine and Kingfisher Counties in the north to Comanche, Stephens, and Carter Counties in the south. The STACK production area are relatively new developments that have the most current exploration and production activity and highest potential for future development, resulting in the need for a lot of water.

The Mississippi Lime production area is active in the north-central counties of Woods, Major, Alfalfa, and Garfield. The Mississippi Lime formation in north-central Oklahoma produces high volumes of water per well, and Woods and Alfalfa Counties are two of the top counties for produced water injection. In addition, operations in the Mississippi Lime formation do not require significant volumes of water for reuse, while the STACK in and around Blaine County need a lot of water for operations.

Figures 2-5 and 2-6 show the Study production areas.

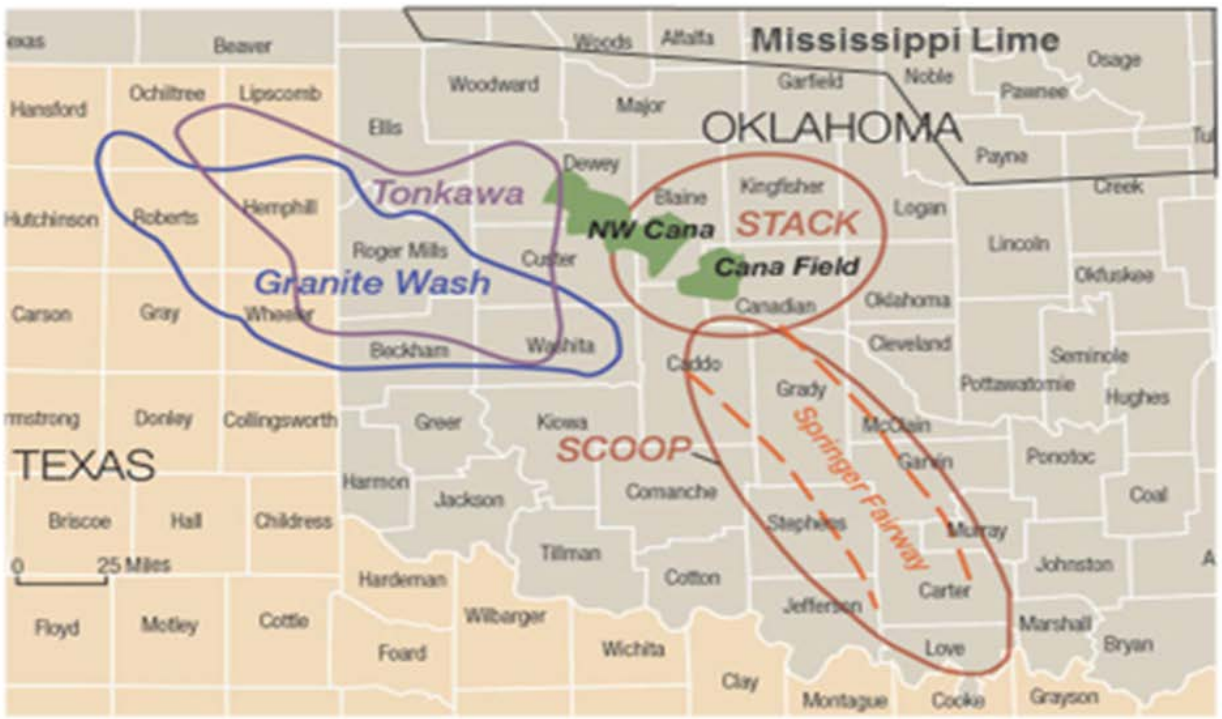


Figure 2-5. The SCOOP Production Area

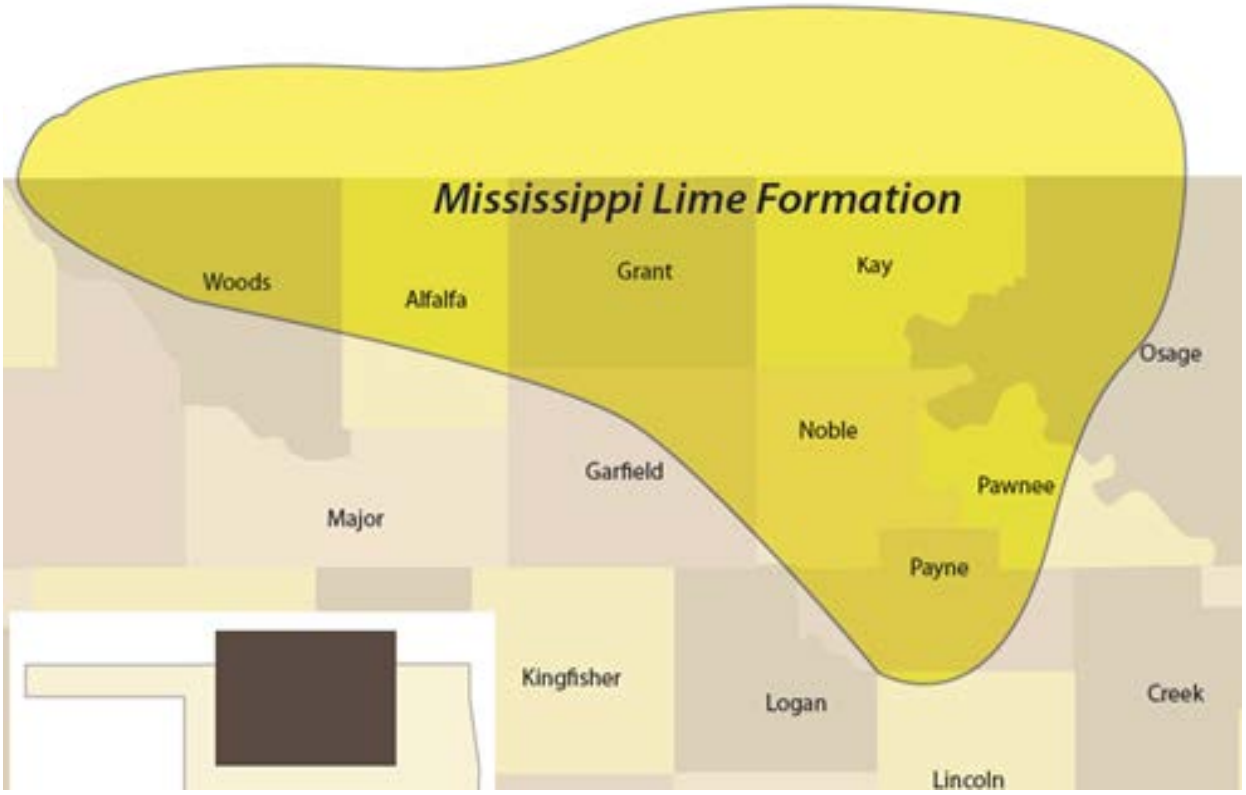


Figure 2-6. The Mississippi Lime Production Area

The Mississippi Lime formation and production area is an oil and natural gas (NG) production area centered along the Kansas and Oklahoma border, with some experts estimating it to extend as far as southern Nebraska, comprising potentially as much as 17 million acres (Petzet, 2012). For this Study,

only the counties within Oklahoma were selected, as the largest share of the production activity has been in northern Oklahoma. The characteristics of a high porosity formation, especially the Mississippi Lime formation, results in high produced water generation (initially and long-term). Mississippi Lime wells produce large volumes of produced water, much more than could be used in subsequent operations in the area; therefore, most produced water in the area is managed through disposal into SWDs. This disposal has potentially contributed to induced seismicity in the state.

The drilling and completion activity in the STACK and SCOOP production areas of central Oklahoma have dominated the industry's activity in the state in recent years. Since 2013, the Meramac and Woodford formations within Kingfisher and Blaine Counties have been the core production areas (Nojek and Li, 2017). STACK and SCOOP have recently become more attractive options for onshore shale operators due to their high initial oil and gas production rates and low water production.

In December 2018, according to the Energy Information Administration, the Anadarko Basin of Oklahoma that includes the STACK and SCOOP areas produced 589,000 bbls of oil per day, or 7.3 percent of the U.S. onshore oil (U.S. Energy Information Administration, 2018). The Anadarko Basin also produced 7.5 billion cubic feet of gas per day, or 10 percent of the U.S. onshore gas. The Baker Hughes rig count in January 2019 indicated that Oklahoma had 140 rigs running, representing 13 percent of U.S. drilling rigs (U.S. Energy Information Administration, 2019).

2.3 Oil and Gas Production Water Demand and Permitting

The oil and gas industry currently use a variety of different water sources, including surface water (lakes, ponds, rivers) and groundwater. Typically, the oil and gas industry purchases water from municipalities, regional and rural water districts, and river authorities. The less common sources of water supplies include wastewater effluent from publicly owned wastewater treatment plants (WWTPs) or industrial and power plant cooling tower effluent water. The other nonpotable water sources include brackish groundwater, drilling reserve pit water, and produced water.

In Oklahoma, most oil and gas well completions use surface water supplies. Figures 2-7 and 2-8 show the 2019 permitted groundwater and surface water demand by water use sector. Oil and gas water use in Oklahoma was projected at 5 percent by 2060 in the Oklahoma Comprehensive Water Plan of 2012 (OWRB, 2012). According to the April 2019 data from OWRB, the permitted groundwater use for oil and gas operations was 146,508 acre-feet (AF) (3.7 percent of total use), surface water was 193,497 AF (6.6 percent of total use), with a total combined use of 340,005 AF, which represents 5 percent of all permitted water use in Oklahoma (OWRB 2019a). As Table 2-1 shows, from 2017 to 2019, oil and gas water use has declined due to the decline in oil and gas production in the state (OWRB, 2019a). The peak oil and gas production years of 2013 and 2014 show an increased number of water use permits. Figure 2-9 shows the long-term projection for water use by the oil and gas sector (OWRB, 2019b).

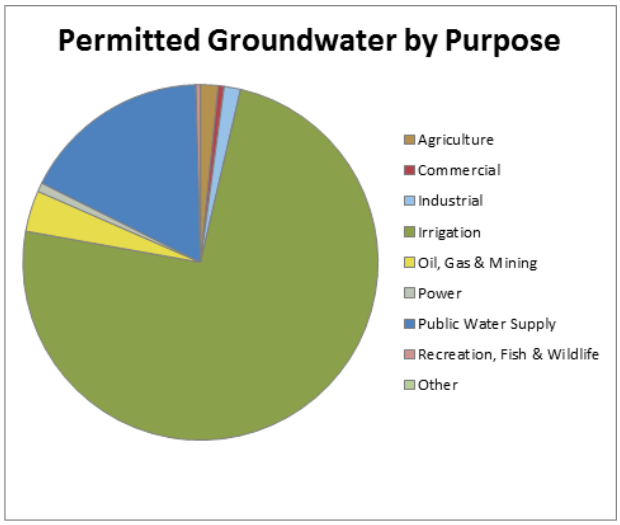


Figure 2-7. Permitted Groundwater in Oklahoma by Water Use Sector in 2019
Source: OWRB 2019b

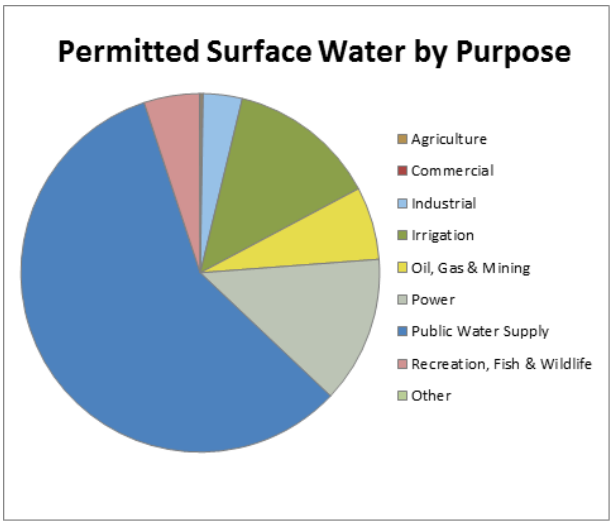


Figure 2-8. Permitted Surface Water in Oklahoma by Water Use Sector in 2019
Source: OWRB 2019b

Table 2-1. Permits by Year, Use Purpose, and Amount Permitted per Water Use Sector in Oklahoma, 2009-2019

Year	Water Use Purpose	Number of Permits	Total Amount Permitted (AF)
1999	Agriculture	8	156
	Commercial	0	0
	Industrial	16	173
	Irrigation	18	3,031
	Oil, Gas, and Mining	640	1,956
	Other	0	0
	Power	0	0
	Public Water Supply	7	822
	Recreation, Fish, and Wildlife	2	278
2000	Agriculture	4	848
	Commercial	1	0
	Industrial	20	283
	Irrigation	29	14,595
	Oil, Gas, and Mining	1,019	2,652
	Other	0	0
	Power	0	0
	Public Water Supply	12	784
	Recreation, Fish, and Wildlife	0	0

Table 2-1. Permits by Year, Use Purpose, and Amount Permitted per Water Use Sector in Oklahoma, 2009-2019

Year	Water Use Purpose	Number of Permits	Total Amount Permitted (AF)
2001	Agriculture	4	210
	Commercial	2	6
	Industrial	22	197
	Irrigation	18	4,980
	Oil, Gas, and Mining	982	2,914
	Other	0	0
	Power	0	0
	Public Water Supply	7	5,917
	Recreation, Fish, and Wildlife	0	0
2002	Agriculture	5	199
	Commercial	2	5
	Industrial	39	427
	Irrigation	27	11,220
	Oil, Gas, and Mining	793	2,270
	Other	0	0
	Power	0	0
	Public Water Supply	12	7,855
	Recreation, Fish, and Wildlife	1	53
2003	Agriculture	4	102
	Commercial	3	643
	Industrial	29	901
	Irrigation	47	11,498
	Oil, Gas, and Mining	1,206	3,233
	Other	0	0
	Power	0	0
	Public Water Supply	9	5,766
	Recreation, Fish, and Wildlife	5	615
2004	Agriculture	4	5,376
	Commercial	0	0
	Industrial	30	174
	Irrigation	29	6,399
	Oil, Gas, and Mining	1,449	5,253
	Other	0	0
	Power	0	0
	Public Water Supply	9	3,252
	Recreation, Fish, and Wildlife	10	1,031

Table 2-1. Permits by Year, Use Purpose, and Amount Permitted per Water Use Sector in Oklahoma, 2009-2019

Year	Water Use Purpose	Number of Permits	Total Amount Permitted (AF)
2005	Agriculture	7	35
	Commercial	0	0
	Industrial	17	118
	Irrigation	25	3,751
	Oil, Gas, and Mining	1,628	5,472
	Other	0	0
	Power	0	0
	Public Water Supply	6	5,702
	Recreation, Fish, and Wildlife	3	446
2006	Agriculture	6	321
	Commercial	4	17
	Industrial	19	81
	Irrigation	49	6,471
	Oil, Gas, and Mining	1,794	3,547
	Other	0	0
	Power	0	0
	Public Water Supply	5	3,698
	Recreation, Fish, and Wildlife	2	79
2007	Agriculture	2	93
	Commercial	0	0
	Industrial	21	264
	Irrigation	12	626
	Oil, Gas, and Mining	1,792	4,229
	Other	0	0
	Power	0	0
	Public Water Supply	7	3,427
	Recreation, Fish, and Wildlife	2	70
2008	Agriculture	0	0
	Commercial	0	0
	Industrial	32	323
	Irrigation	15	4,874
	Oil, Gas, and Mining	1,993	7,957
	Other	0	0
	Power	0	0
	Public Water Supply	4	5,620
	Recreation, Fish, and Wildlife	0	0

Table 2-1. Permits by Year, Use Purpose, and Amount Permitted per Water Use Sector in Oklahoma, 2009-2019

Year	Water Use Purpose	Number of Permits	Total Amount Permitted (AF)
2009	Agriculture	1	160
	Commercial	1	2
	Industrial	49	442
	Irrigation	16	4,900
	Oil, Gas, and Mining	875	6,486
	Other	0	0
	Power	0	0
	Public Water Supply	3	2,870
	Recreation, Fish, and Wildlife	0	0
2010	Agriculture	1	30
	Commercial	0	0
	Industrial	36	330
	Irrigation	13	4,253
	Oil, Gas, and Mining	1,286	9,320
	Other	0	0
	Power	3	48
	Public Water Supply	6	3,109
	Recreation, Fish, and Wildlife	1	160
2011	Agriculture	10	357
	Commercial	0	0
	Industrial	61	2,016
	Irrigation	36	13,071
	Oil, Gas, and Mining	1,895	15,702
	Other	0	0
	Power	1	1
	Public Water Supply	8	3,259
	Recreation, Fish, and Wildlife	3	36,650
2012	Agriculture	3	60
	Commercial	5	8
	Industrial	76	1,420
	Irrigation	44	15,450
	Oil, Gas, and Mining	2,270	23,546
	Other	0	0
	Power	0	0
	Public Water Supply	13	3,554
	Recreation, Fish, and Wildlife	6	58,674

Table 2-1. Permits by Year, Use Purpose, and Amount Permitted per Water Use Sector in Oklahoma, 2009-2019

Year	Water Use Purpose	Number of Permits	Total Amount Permitted (AF)
2013	Agriculture	0	0
	Commercial	2	2
	Industrial	57	508
	Irrigation	41	6,501
	Oil, Gas, and Mining	2,048	27,447
	Other	0	0
	Power	0	0
	Public Water Supply	10	5,432
	Recreation, Fish, and Wildlife	4	58,640
2014	Agriculture	0	0
	Commercial	1	1
	Industrial	56	510
	Irrigation	36	9,684
	Oil, Gas, and Mining	1,925	31,023
	Other	0	0
	Power	0	0
	Public Water Supply	9	6,520
	Recreation, Fish, and Wildlife	8	60,816
2015	Agriculture	1	3
	Commercial	5	25
	Industrial	59	439
	Irrigation	25	4,582
	Oil, Gas, and Mining	1,203	20,768
	Other	0	0
	Power	0	0
	Public Water Supply	19	9,855
	Recreation, Fish, and Wildlife	6	58,906
2016	Agriculture	2	4
	Commercial	3	4
	Industrial	35	293
	Irrigation	14	1,354
	Oil, Gas, and Mining	1,153	24,088
	Other	0	0
	Power	0	0
	Public Water Supply	16	10,360
	Recreation, Fish, and Wildlife	9	58,665

Table 2-1. Permits by Year, Use Purpose, and Amount Permitted per Water Use Sector in Oklahoma, 2009-2019

Year	Water Use Purpose	Number of Permits	Total Amount Permitted (AF)
2017	Agriculture	1	3
	Commercial	1	5
	Industrial	96	416
	Irrigation	23	4,267
	Oil, Gas, and Mining	1,515	40,912
	Other	0	0
	Power	0	0
	Public Water Supply	19	22,458
	Recreation, Fish, and Wildlife	13	1,123
2018	Agriculture	11	474
	Commercial	8	31
	Industrial	78	719
	Irrigation	38	4,183
	Oil, Gas, and Mining	1,547	49,632
	Other	0	0
	Power	0	0
	Public Water Supply	5	15,595
	Recreation, Fish, and Wildlife	4	89
2019	Agriculture	5	67
	Commercial	0	0
	Industrial	38	317
	Irrigation	6	411
	Oil, Gas, and Mining	328	13,431
	Other	0	0
	Power	0	0
	Public Water Supply	0	0
	Recreation, Fish, and Wildlife	1	5

Source: OWRB 2019a

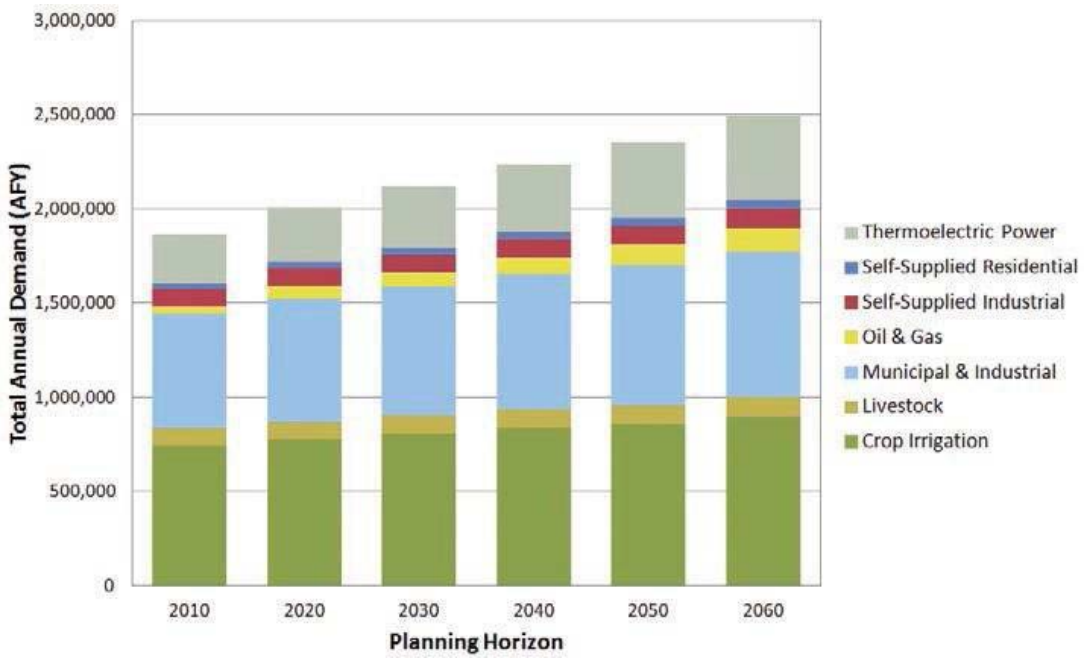


Figure 2-9. Projected Statewide Demand by Water Use Sector from 2010-2060
Source: OWRB 2019b

Municipal wastewater is a potential source for oil and gas hydraulic fracturing; however, to date, this resource remains untapped. In 2017, the Oklahoma City Water Utilities Trust and the Oklahoma City Council announced an agreement between Devon and Oklahoma City to give Devon the option to use treated wastewater from Oklahoma City's Deer Creek and Chisholm Creek WWTPs, which has yet to be implemented; Devon's projections later determined that transfer costs of wastewater would not be cost-effective at this time. There are three known municipal wastewater projects linked to oil and gas development in the Permian Basin of west Texas and southeast New Mexico. Midland and Odessa, Texas and Carlsbad, New Mexico all sell or have contracts to sell municipal wastewater to producing companies or a distribution pipeline for hydraulic fracturing.

Anyone using groundwater or water from streams for agricultural, industrial, public water supply, or other nondomestic purposes must obtain a permit from OWRB. Groundwater is considered the private property of the surface owner, although it is subject to reasonable regulation by the OWRB. Stream water (or surface water) is considered to be publicly owned and subject to appropriation by the OWRB. Most water in reservoirs, ponds, and lakes is considered water in a "definite stream" and public; therefore, is subject to state appropriation (OWRB 2019c).

Beneficial use of water is a fundamental requirement in the administration of water rights. Beneficial uses include the following:

- Agriculture
- Irrigation
- Water supply
- Hydroelectric power generation
- Municipal
- Industrial
- Navigation
- Recreation
- Fish and wildlife propagation

Provisional temporary (PT) permits are most frequently sought by oil and gas companies requiring water for the drilling and completion of wells. PT permits may be approved by the executive director of the

OWRB and do not require public notice and a hearing. These PT, nonrenewable permits do not exceed 90 days and are subject to cancellation at any time during the term. These permits can be granted for both groundwater and surface water. Figure 2-10 shows the total volume of water allocated to PT permits by water source (OWRB 2019b).

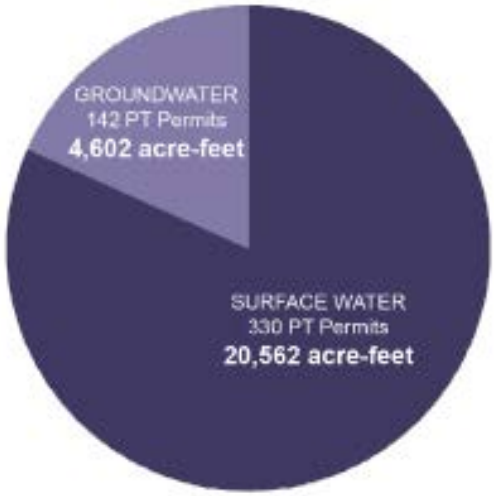


Figure 2-10. Total Allocated Volume of Water to Provisional Temporary Permits by Water Source in 2018

Source: OWRB 2019b

Table 2-2 breaks down the water uses for Mississippi Lime and STACK production areas per county in 2018 (OWRB 2019a).

Table 2-2. Oil and Gas Water Use in Mississippi Lime and STACK Production Areas per County in 2018

Formation	County	O&G PTs	O&G (AF)	All PTs	All Uses (AF)	O&G % of PTs	O&G % of Vol of All Uses
Mississippi Lime	Alfalfa	24	411	24	411	-	-
	Garfield	39	839	45	1,152		-
	Major	73	1,601	79	1,924	-	-
	Woods	22	694	24	886	-	-
Total		158	3,545	172	4,373	92	81
STACK	Blaine	207	5,621	215	5,630	-	-
	Kingfisher	240	9,461	240	9,461	-	-
Total		447	15,082	455	15,091	98	100
Statewide	All Counties	1,547	49,632	1,691	70,723	91	70

Source: OWRB 2019a

AF = 1 acre-foot of water (the amount of water covering 1 acre to a depth of 1 foot) equals 326,000 gallons or 43,560 cubic feet of water

O&G = oil and gas

3. Produced Water Quality

Characterization of the produced water quality indicates the water is suitable for reuse. While the physical, chemical, and biological characteristics of produced water are not well documented, a better understanding of produced water quality characteristics would help to address the feasibility of the two alternatives for this Study: (1) produced water transfer from the Mississippi Lime production area to STACK production area through a pipeline, and (2) evaporation of produced water in the Mississippi Lime production area.

Due to a lack of publicly available data, this Study included limited sampling and analysis of produced water from the Mississippi Lime and STACK areas, with the goal of characterizing the produced waters and providing a database that can be used in future evaluations for scaling potential and compatibility with formation and hydraulic fracturing operations. This section summarizes the results of the analysis, with a technical memorandum documenting the details on the methods, results, and data quality validation of the analysis (provided in Appendix B).

3.1 Summary of Sampling and Analysis

A total of eight water quality samples were collected from a single SWD facility that receives produced water from both Mississippi Lime and STACK formations. These samples were assessed for a limited set of analytes, including the following:

- General water quality characteristics
- Major ions and trace elements
- Petroleum hydrocarbon (PHC)-related organics
- Gamma emitting radionuclides

The TDS levels of these samples ranged from 86,000 to 210,000 milligrams per liter (mg/L), which were comparable to other onshore basins around the U.S.:

- Barnett, 60,000 mg/L
- Marcellus Shale 180,000 mg/L
- Permian 140,000 mg/L
- Woodford 110,000 mg/L
- Denver-Julesburg 25,000 mg/L (Lauer et al., 2018)

In the PWWG Report, the Blaine (SCOOP) and Kingfisher (STACK) had the median TDS values of 17,000 and 25,000 mg/L, respectively. The PWWG Report included median values for Alfalfa and Woods Counties (Mississippi Lime) as 86,000 to 210,000 mg/L, respectively. The samples from Mississippi Lime in Alfalfa and Woods Counties had TDS concentrations ranging from 86,000 to 210,000 mg/L. Similarly, TDS concentrations of 152,000 to 218,000 mg/L were recorded in the PWWG Report.

Additionally, the total organic carbon levels—28 to 157 mg/L—were similar to other high TDS basins. For example, the Marcellus shale ranges from approximately 150 mg/L during flowback to 20 to 40 mg/L for later staged produced water. pH levels were very close to neutral, as expected due to the bicarbonate levels that were present in the samples.

Calcium, iron, and magnesium exceeded common recommended values for production well stimulation; however, the industry does not have a consistent criterion among companies.

Sulfate levels were elevated, ranging from 299 to 705 mg/L. Barium concentrations were low, which may lead to sulfate being the dominant electron acceptor under anaerobic conditions for sulfate-reducing bacteria (SRBs), thereby favoring the proliferation of these microorganisms. An abundance of SRBs may lead to H_2S generation and biofouling.

PHC-related compounds were assessed by measuring diesel-range organics (DRO) and gasoline-range organics (GRO), as well as benzene, toluene, ethylbenzene, and xylenes (BTEX). VOCs and semivolatile organic compounds (sVOCs) were detected in all samples. GRO represent the volatile range of the PHCs in these samples, whereas DRO represent the semivolatile range. GRO and DRO may indicate what fraction of the total petroleum hydrocarbons present will volatilize out of the produced water versus what will remain in the aqueous or suspended phase.

There was no discernable pattern in the ratio of GRO to DRO. BTEX are water soluble VOCs that are found in PHCs. They are known to be toxic to humans, and common exposure routes include ingestion and inhalation. The rate that VOCs volatilize depends on a number of physical parameters, including temperature and surface area. However, if these waters are to be evaporated as a means of disposal, it would be important to consider VOC impacts to air quality[7]. Furthermore, sVOCs may be concentrated in residuals and should be addressed as part of disposal options to minimize OVC emissions.

The method detection limit (MDL) for gross alpha and beta were elevated and exceeded potential concentrations of concern; therefore, the presence of gamma-emitting radionuclides cannot be discounted in samples with no detected measurable concentrations.

Radium levels were elevated, with measured concentrations between 61.3 to 1,320 picocuries per liter (pCi/L). However, this is consistent with other produced water samples, such as those in the Bakken, which have total radium activity up to 1,700 pCi/L (Lauer et al. 2016) and other non-Marcellus produced waters (median of 1,011 pCi/L [Rowen et al. 2011]). High radium produced water from the Marcellus, which averages around 5,500 pCi/L, has been measured up to 18,000 pCi/L (Rowen et al. 2011). For comparison, the industrial wastewater effluent discharge limit is 60 pCi/L for Ra-226 (Rowen et al. 2011). Moreover, radium can sorb to organic and clay material or co-precipitate with sulfate or carbonate minerals. Therefore, there is the possibility that radium will concentrate in the solids or scale minerals, and radium-bearing sludge or scales may exceed waste exemption values. While currently not defined in Oklahoma, other states have placed exemption values between 5 to 50 pCi/g (Smith et al., 1999).

In addition to the analytical concentration of radionuclides detected and measured in these produced waters, it is important to note an elevated MDL means the presence of NORM cannot be eliminated. Therefore, NORM potentially present at levels of concern must be considered in both residuals' management and scale precipitation.

3.2 Produced Water Quality Findings and Next Steps

The findings from the evaluation of the produced water quality samples can be summarized as follows:

- While this sampling effort provides additional insight into the quality of the produced water, the Study was limited in scope and experienced challenges with the sampling and analyses, which makes some of the data unreliable.
- The Mississippi Lime samples from Alfalfa and Woods Counties had TDS concentrations ranging from 86,000 to 210,000 mg/L. Similarly, TDS concentrations of 152,000 to 218,000 mg/L were recorded in the PWWG Report. While samples from this Study did not include Blaine and Kingfisher Counties, the PWWG Report stated the TDS median values for those counties were 17,000 and 25,000 mg/L, respectively.
- All samples contained chloride concentrations between 30,000 and 50,000 mg/L, which exceeds a suggested guideline level for production well stimulation (Liden et al., 2018).
- Calcium, iron, and magnesium exceeded values commonly recommended for production well stimulation, but industry does not have consistent criteria among companies.

[7] Volatile organic compounds (VOCs) includes a group of chemicals that contribute to the formation of ground-level ozone (smog). EPA, 0219: Basic Information about Oil and Natural Gas Air Pollution Standards. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/basic-information-about-oil-and-natural-gas

- Sulfate levels were elevated, ranging from 299 to 705 mg/L. Barium concentrations were low, which may lead to sulfate being the dominant electron acceptor under anaerobic conditions for SRBs; therefore, favoring the proliferation of these microorganisms. An abundance of SRBs may lead to H_2S generation and biofouling.
- VOCs and sVOCs were detected in all samples, so if these waters are to be evaporated as a means of disposal, it would be important to consider VOC impacts to air quality. Furthermore, the sVOCs may be concentrated in residuals and should be addressed as part of disposal options.
- Total radium activity (Ra-226 + Ra-228) ranged from 61.3 to 1,320 pCi/L.
- The MDL for gross alpha and beta were elevated and exceeded potential concentrations of concern; therefore, the presence of gamma-emitting radionuclides cannot be discounted, even in samples that measured nondetect.
- There is the possibility that radium will concentrate in the solids or scale minerals; therefore, radium-bearing sludge or scales may exceed waste exemption values.

The next steps of the Study are to further characterize and evaluate produced water qualities to address the following concerns and risks associated with the transfer pipeline and evaporation alternatives:

1) Further characterization of produced water quality, and collaboration with oil and gas producers to share water quality information. Additional water quality data are required to confirm unreliable results from this sampling effort, such as TDS in the STACK and SCOOP produced water, and supplement the data set collected for further analysis and evaluations, as discussed herein.
2) Scaling analysis to determine scaling potential of the produced water and mixing of different formations' waters. The mixing of different formations' waters could potentially create scale precipitation, which could create operational problems that may include solids buildup in pipelines, vessels, and pumps.
3) Qualitative and quantitative evaluation of impacts from produced water spills and subsequent remediation requirements.
4) Core testing of Mississippi Lime produced water formation core samples. The water from Mississippi Lime could potentially negatively impact the performance of the new hydraulically fractured well where the reuse occurs. For the producing companies investing in explorations and operations, any measurable reduction in well performance due to water quality would be risky. This risk may be partially mitigated by performing minimal treatment of the water to be used in the hydraulic fracturing.
5) Evaluation of treatment requirements and costs. The effectiveness and costs of the water treatment processes are impacted by the produced water quality.
6) Pilot testing of evaporation technologies to determine the following:
    - Whether overspray of produced water beyond the permitted evaporation site can result in soil and air contamination by certain key constituents[8]
    - What the key constituents of concern are in such operations, and what elevated levels measured, if any, would be acceptable
    - The amount and type of solids generated (including NORM) that are dependent on the produced water quality
    - The potential for air emissions, such as VOCs

[8] See Appendix C for OCC Regulation: Pollution Abatement Rule: Title 165:10 Subchapter 7

4. Produced Water Transfer

This section describes the concept of treating and transferring produced water from the water-rich Mississippi Lime area through a pipeline network to the water-poor STACK area, which could use the additional water for its hydraulic fracturing operations, potentially saving billions of barrels of freshwater that would otherwise that would otherwise be evaporated, eliminating the possibility of reuse. The project concept was initially described in the PWWG Report, which evaluated a gathering system to collect 200,000 bpd from individual disposal wells, the cost of the pipeline, and required storage and minimal treatment requirements. The transfer pipeline cost spread for a 10-year period was $1.01/bbls for a 200,000-bpd scenario.

Building from the results of the PWWG Report, this Study further evaluated the transfer pipeline system, including the following:

- Pipeline Route
- Treatment and Storage
- Cost Evaluation
- Implementation Considerations (risks, regulatory, implementation schedule)
- Produced Water Transfer through Pipeline Findings, Next Steps and Feasibility

This section provides additional details on the transfer pipeline evaluation and provides a summary of the findings and next steps.

4.1 Project Participants

The project Study Partners included the following:

- OWRB Project Manager
- EDF representatives
- BEG representative
- GWPC representatives
- Jacobs engineering team
- Oklahoma Corporation Commission (OCC) representatives
- Oklahoma Department of Environmental Quality (ODEQ) representatives
- Other representatives from the oil and gas industry

4.2 External Participation

The first steps of the Study included collecting data and engaging industry, regulatory agencies, and other external stakeholders in developing a more in-depth understanding of opportunities and constraints for produced water reuse in oil and gas operations and produced water disposal by evaporation. Key representatives from the state's regulatory agencies and academia, as well as representatives from industry, participated in two workshops comprising facilitated group discussions as well as technical presentations by industry professionals and regulatory agencies. The first workshop, held on January 16, 2018, focused on produced water transfer to oil and gas operations. The second workshop, held on January 17, 2018, focused on produced water evaporation. The specific goals and objectives for each workshop and the outcomes are summarized in the following sections. A list of participants is included in Table 4-1.

Table 4-1. Produced Water Transfer Workshop Participants January 16, 2018

Oil and Gas Representatives		OWRB Staff, Agencies, Study Partners, and Consultants	
Participant Name	**Organization**	**Participant Name**	**Organization**
Nick Cohen	Invenergy	Lindsey Atkinson	Jacobs
John Durand	WaterBridge[c]	Shellie Chard	ODEQ
Mitch Elkins	Midstates Petroleum Co.[a]	Anna Childers	Jacobs
Kevin Heasley	Sandridge Energy[a]	Julie Cunningham	OWRB
Robert Huizenga	Cimarex[b]		
Preston Jones	D&B Oilfield Services[c]	Michael Dunkel	Jacobs
Doug Kathol	WhiteStar[a]	Nathan Kuhnert	Reclamation
Jarrod Maly	D&B Oilfield Services[c]	Mark Layne	GWPC
Mike Mathis	Continental[b]	Owen Mills	OWRB
Thomas McCormick	Marathon Oil Corp.[b]	Mike Moore	OCC
Rick McCurdy	Chesapeake Energy[a]	Dan Mueller	EDF
Naggs Nagghappan	Veolia[c]	Nichole Saunders	EDF
Stephen McNair	H2O Midstream[c]	Michael Teague	Sec. of Energy and Environment
Ken Nichols	Devon Energy[b]	Scott Thompson	ODEQ
Jesse Sandlin	Devon Energy[b]	Kevin Wagner	OK Water Resources Center (OSU)
James Welch	Veolia[c]	Dan Yates	GWPC

[a] Mississippi Lime Play Operators

[b] STACK and SCOOP Play Operators

[c] Midstream Water Treatment Companies

Notes:

Location of the meeting: Oklahoma History Center 800 Nazih Zuhdi Dr, Oklahoma City, OK 73105 (Fischer Board Room)

OSU = Oklahoma State University

SCOOP = South Central Oklahoma Oil Province

4.2.1 Produced Water Transfer Workshop

Figure 4-1 summarizes the goals and objectives of the Produced Water Transfer Workshop. By directly engaging external stakeholders, opportunities and challenges regarding the transfer of produced water through a pipeline from the Mississippi Lime play to the STACK and SCOOP play were better understood.

Goal 1: Ensure water reuse buy-in by directly engaging stakeholders	Goal 2: Better understand opportunities and constraints	Goal 3: Identify information gaps and prioritize information needs
Objectives: • Engage industry and other stakeholders to identify future research needs, such as produced water quality requirements for oil and gas industry and regulations to incentivize produced water transfers through a pipeline • Continue OWRB's PWWG efforts	*Objectives:* • Estimate current produced water supplies and demands • Identify potential risks of storing and transferring produced water through a pipeline • Identify oil and gas industry's long-term water management goals, such as operational priorities, potential water management strategies	*Objectives:* • Collect information on existing produced water infrastructure: storage, transfer, and treatment; interconnectedness of the existing water systems • Obtain costs of produced water treatment, sourcing, and disposal • Analyze produced water quality requirements for water transfer through a pipeline

Figure 4-1. Goals and Objectives of Produced Water Transfer Workshop

While the overall benefits of reduced disposal in the Mississippi Lime play and reduced freshwater sourcing in the STACK production area likely improves the long-term economic viability of both plays, the technical and economic feasibility of implementing a produced water transfer pipeline includes many risks. In a facilitated discussion, the workshop participants identified the potential stakeholder, financial, legal, and regulatory risks associated with the pipeline, which are discussed further in Section 4.

Two major variables were identified and discussed at the workshop that could impact the feasibility of implementing produced water transfer between the two oil and gas production areas: (1) produced water quantity (supply and demand) and (2) produced water quality.

Findings regarding produced water quantity, including the following, and are summarized in Table 4-2 and Table 4-3:

- Clarify the existing legal arrangements; and develop new legal and regulatory mechanisms to sell, purchase, or own produced water before and after treatment. Identify the roles of different parties of interest, such as landowners, mineral owners, different water users, treatment entities, and payees of the produced water infrastructure.
- Optimize the produced water service area in the STACK production area. Consider a two-phased approach to determine the layout of pipeline infrastructure from the Mississippi Lime to the STACK: (1) use the existing disposal infrastructure and (2) incorporate plans to build dedicated infrastructure for produced water transfer and use for oil and gas operations.
- Optimize water supplies and demands. Identify locations of hydraulic fracturing and the amount of water needed daily to further advance contractual elements of produced water transfer, and distribution of costs, obligations, and benefits.
- Consider the role of pipeline classification and the potential legal issues, such as right-of-way (ROW); for example, designating the produced water pipeline as a common carrier pipeline (similar to the transportation of crude petroleum). Common carrier pipelines may have a statutory right of eminent domain, which could be beneficial for siting.
- Develop and analyze different cost structures to fund the produced water transfer infrastructure.
- Determine water quality goals for the oil and gas operations; specifically, identify concerns, considerations, or treatment requirements that might be necessary to reuse produced water from the Mississippi Lime production area for operational needs in the STACK production area.

Table 4-2. Produced Water Transfer Workshop: Water Quantity Challenges and Opportunities from Produced Water Transfer through a Pipeline from Mississippi Lime to STACK Production Area in Oklahoma

Mississippi Lime Production Area	STACK Production Area	Water Transfer through a Pipeline
• Disposal of large quantities of water is challenging; often ranging from 210,000-450,000 bpd from individual companies. • Decline rates of produced water are insignificant despite the performance of oil and gas production rates[a]. • Earthquake-prone areas are restricting disposal via SWDs. • Current disposal costs range from $0.06-0.2/bbls. Producers stated that if disposal costs increase $0.05/bbls, production would not be cost-effective at this time. • The demands on freshwater have increased from 5 million bbls to 15-20 million bbls per well because more water has been needed for longer laterals (9,000-10,000 feet) and well completion plans. However, the higher water demand has yet to be an issue because, to date, oil prices and drilling activity have been low. • Most (95-98%) of produced water is piped from tank batteries through a pipeline to SWDs (limited amounts are trucked); the rest of the produced water is used for hydraulic fracturing and drilling fluids.	• Disposal is less in STACK area than in Mississippi Lime (10,000-15,000 bpd) and is not a problem; however, there are public perception issues due to trucking produced water. • On average, 50,000 bpd per well of freshwater are used for frac spread[b]. • Cost: – Estimate in the PWWG Report: $1.09/bbls, including sourcing and disposal costs[c] – SWDs owned by the operators have lower disposal and operating costs than commercial SWDs – Average cost of sourcing freshwater is approximately $0.5/bbls • There is a mix of freshwater sources used for production, with the main source being surface water. Some reuse of produced water.[d] • Some producers use their existing infrastructure to pipe produced water to SWDs, but it is mostly trucked (75-90%).	• Variable quantity and timing of water supply and demands between the production areas may be the largest challenge to making the operation feasible. • Sizing of the pipeline will depend on the STACK production area's needs, including[e]: – Under-sizing the pipeline may be the easiest to successfully implement because it is can more often be maintained at or near capacity. – Alternatively, over-sizing the pipeline is unnecessary, as a larger pipe will more often be underutilized; hence, the average cost per barrel would be higher. • There is a potential opportunity to use existing disposal pipeline infrastructure in the Mississippi production area to connect to the STACK area, including: – Use a leg off of the trunk line to incorporate into existing infrastructure so that water could be handled or moved throughout the production area. – The existing pipelines are multidirectional; thus, can move water across areas. In some instances, bidirectional lines connect up to five SWDs. • There are currently undefined regulatory and legal aspects of produced water ownership before and after treatment, as well as considerations for siting and transfer.

[a] The production rates decline as a function of time from the loss of reservoir pressure or changing relative volumes of the produced fluids. Produced water rates decline if no more wells are completed. But all operational wells, despite their performance rating, keep on producing water. The workshop participants reported the rate of decline from 2 to 20 percent. The operators reported different decline rates during the life cycle of the well: some reported a 10 percent decline in wells that have been in operation for 3 to 4 years, whereas others reported very little produced water decline in wells that have been in operation for 10 years.
[b] One hydraulic fracture spread was reported to use approximately 65,000 bpd (a hydraulic fracture spread is the set of pumps used during the hydraulic fracturing job). The industry representatives at the workshop stated that nine hydraulic fracturing crews were identified, for a total of 450,000 bpd (9 times 50,000 bpd).
[c] The workshop participants agreed on the estimate, especially if the transportation costs are excluded. Disposal costs depend heavily on whether the infrastructure is owned.
[d] Approximately 10,000 to 30,000 bpd, depending on the company.
[e] In the PWWG Report, the proposed pipeline was sized at 200,000 bpd.
Notes:
% = percent
bbls = barrel(s)
bpd = barrel(s) per day

- Determine regulatory considerations for the permitting of a pipeline, including the following:
  - Classification of produced water (for example, type of waste, resource)
  - Liability for produced water leaks and spills from a combined or shared pipeline
  - Determination of the custody of produced water, including when ownership begins
  - Permitting and regulatory authority over produced water transfer
- Clarify the existing regulations for the disposal or reuse of large volumes of excess salts from Mississippi Lime production area.

Table 4-3. Produced Water Transfer Workshop Outcomes: Water Quality Challenges and Opportunities from Produced Water Transfer through a Pipeline from the Mississippi Lime to STACK Production Area in Oklahoma

Mississippi Lime Production Area	STACK Production Area	Water Transfer through a Pipeline
• TDS: Average of 200,000 ppm.[a] • Produced water in Mississippi Lime does not contain barium or sulfate. • Potential scaling problems with hardness, iron, and boron.	• TDS: Average of 30,000 ppm.[a] • Reuse of waters from another reservoir having very different properties could affect the performance of the receiving reservoir.	• Variability of water quality between formations may impact oil and gas operations; challenge to treat water to specifications: TDS, bacteria, barium, chloride, and pH that can cause scale deposits on the surface of oil and gas infrastructure, corrosion, or friction. • The potential for spills and leaks creates environmental risks that are costly to mitigate. • To mitigate risks of spills and leaks, technologies, such as high-quality pipeline, automation, block valves to isolate the system, and leak detection systems for shut-in, need to be built into the costs of the project. • In current practice, source waters are typically blended by a pipeline operator or by the company taking the produced water to meet local fracking-water[b] specs. High TDS water typically needs additional chemicals to reduce friction while pumping at high rates into wells for hydraulic fracturing.

[a] As reported in the PWWG Report and discussion during the workshop by the producers.

[b] Fracking water or frack water is the water and chemical mix used in the hydraulic fracking of injecting water, sand and chemicals at high pressure in to shale and other tight rock formations to release oil and gas.

Notes:

ppm = part(s) per million

TDS = total dissolved solids

4.2.2 Produced Water Evaporation Site Visit and Workshop

Prior to the Evaporation Workshop, the Study Partners visited Poseidon Salt Water Systems, the first permitted commercial evaporation facility in Oklahoma, to learn about the operations and permitting requirements.[9] The facility is located in Grant County, within the Mississippi Lime production area, where wells produce large quantities of high saline water.

4.2.2.1 Site Visit

The site visit allowed the Study Partners to better understand the general operations, operational risks, and stakeholder risks of a spray-type evaporator system (Figure 4-2).

During the site visit, Poseidon described and demonstrated their multi-phased pretreatment process. Poseidon's OCC permit described the general operating procedures (OCC 2016): [10]

[9] Poseidon Saltwater Systems was permitted in 2016.

[10] In Poseidon's OCC application, the applicant asked for authorization for 20,000 bpd of produced water, with an evaporation area with a 300-foot radius, lined with a 60-millimeter polyethylene liner that would cover the entire footprint of the area and would extend outside to

- A basket filtration process removes larger solids; oil is separated from the produced water with a gun barrel, followed by a settling period for the removal of any additional solids.[11]
- A hydrogen sulfide (H_2S) detection and removal process is applied and followed by a cone filtration system. A sequence of chemical treatment tanks targets additives; this process is tailored to the constituents in specific produced water, which is then processed through flocculation tubes to thoroughly mix the fluid.
- A dissolved air filtration (DAF) unit forces the separation of other remaining unwanted elements, including oils solids. The DAF process includes use of chemicals to adjust the pH. The last two filtration processes include an active bead filtration and clay filtration.
- Treated and filtered water is sprayed through commercial misters into an evaporation area, where the water evaporates, and the salt collects on the liner, where water would be harvested with the intent to sell. The misters are designed to reduce the water and chloride mixture to droplets of approximately 100 micrometers in size (the smaller the droplet, the quicker the water evaporates). During the site visit, the vaporizer area had polyethylene liners to catch water and salt. The evaporation area was not covered for operational reasons. The vaporizers were surrounded by a tight plastic mesh fence (50 by 50 yards or 2,500 square yards). The netting was held by 40-foot-tall poles supported by guy wires grounded to concrete blocks. The netting is designed for 70 miles per hour (mph) winds, but the operations cease when winds exceed 50 mph. Any water that fell to the mat below the mister was circulated back into the system.


Figure 4-2. Site Visit Photos, Evaporator Facility: Evaporation Area and Chemical Treatment Area
Photos used with Poseidon's permission

Key determinations from the site visit include the following:

- Northwestern Oklahoma has multiple wells shut-in[12] due to disposal limitations. Additionally, most commercial SWDs are shut-in in that area. While the Poseidon facility could not process enough produced water to handle all of the water in the area, it may allow some of the oil wells to return to production.
- Sufficient area is needed for a liner to catch condensation and allow drainage associated with the evaporation area.
- Some concerns with overspray were evident:
  - Overspray could potentially contaminate soil around the evaporation facility with salts. The OCC regulatory limit for salts in soil is described in OCC Rule in Oklahoma Administrate Code (OAC) as electrical conductivity (EC) less than 4,000 micromhos per centimeter (less than 2,640 ppm total suspended solids [TSS]) on soils having an exchangeable sodium percentage no greater

cover a berm around the perimeter of the evaporation area. According to the application, the rated efficiency of the evaporation process is 80%, with misters spraying at a rate of 2 bpd.

11 Solid wastes generated by the facility are transported to a commercial disposal facility.

12 Shut-in is defined as a state or period in which an oil or gas well has available but unused capacity.

than 15. The allowed application rate for produced water to such soils is calculated from a soil loading standard concentration of 6,000 pounds of TSS per acre less the receiving field's TSS (OAC 165:10-7-17)

  - Salts could potentially travel through the air from the site and impact surrounding areas.

- Regulations for selling the by-product of evaporation (salts) is uncertain in Oklahoma.
- The solids need to be tested for naturally occurring radioactive material (NORM). Currently, the ODEQ regulates NORM.
- Some concerns were evident regarding potential risks of volatile organic compounds (VOCs) from treatment processes.
- Testing and monitoring protocols, including operations and adaptive management, must be adopted, including the following:
  - Influent water quality (in-line testing)
  - Incoming water volume (matching the volumes delivered with the evaporation capacity)
  - Effluent water quality
  - Soil contamination (a leachate collection system beneath the evaporation area should be monitored to track saline concentrations)
  - Site security
  - Weather conditions
  - Effects on wildlife
  - Spills and leaks
  - Air quality effects, including VOCs
  - Trucking of water to the facility (a truck normally hauls approximately 120 bbls of water, so if the processing capacity of an evaporation facility is 10,000 bpd, it could take approximately 83 truckloads to deliver water)

4.2.2.2 Presentations and Workshop Discussion

Building upon the evaporation facility site visit, the Produced Water Evaporation Workshop was held to determine the most recent information on evaporation technologies and discuss the opportunities and risks of this select alternative from the PWWG Report. Information obtained during the workshop and issues raised by external stakeholders were used by the Study Partners to guide this Study.

The goals and objectives for the workshop included obtaining information regarding existing evaporation industry practices and current regulatory framework (Figure 4-3).

Goal 1: Evaporation Industry Practices

Objectives:

- Identify existing testing protocols to characterize influent and effluent to improve treatment technologies and to reduce potential emissions
- Establish needed infrastructure to store water onsite (impoundments or tanks)
- Identify monitoring, prevention, and mitigation measures and protocols for air emissions, spills, transport, loading and offloading, adverse weather events

Goal 2: Current Regulatory Framework

Objectives:

- Identify permitting requirements for by-product reuse and sale
- Identify residual solid waste management required protocols, including chemical characterization, transport, and disposal or reuse
- List potential emissions and impacts to wildlife and soils; characterization protocols for salt overspray; impacts of overall footprint of operations, odor, and traffic

Figure 4-3. Goals and Objectives of Evaporation Workshop

Workshop participants are listed in Table 4-4.

Table 4-4. Produced Water Evaporation Workshop Participants January 17, 2018

Industry Representatives		OWRB Staff, Agencies, Study Partners, and Consultants	
Participant Name	**Organization**	**Participant Name**	**Organization**
Patrick Beck	Southwestern Energy	Lindsey Atkinson	Jacobs
Nick Cohen	Invenergy	Anna Childers	Jacobs
Brent Halldorson	Fountain Quail Energy Services[c]	Julie Cunningham	OWRB
Kevin Heasley	Sandridge Energy[a]	Michael Dunkel	Jacobs
Dennis Hudgens	Poseidon Saltwater Systems[c]	Lloyd Kirk	ODEQ
Robert Huizenga	Cimarex[b]	Nathan Kuhnert	Reclamation
Mike Mathis	Continental[b]	Mark Layne	GWPC
Thomas McCormick	Marathon Oil Corp.[b]	Owen Mills	OWRB
Rick McCurdy	Chesapeake Energy[a]	Mike Moore	OCC
Trey Moore	Logic Energy Solutions[c]	Dan Mueller	EDF
Chris Morss	IDE Technologies[c]	Nichole Saunders	EDF
Ken Nichols	Devon Energy[b]	Scott Thompson	ODEQ
Jesse Sandlin	Devon Energy[b]	Kevin Wagner	OK Water Resources Center (OSU)
Alan Schartz	Poseidon Saltwater Systems[c]	Dan Yates	GWPC
Kushal Seth	Gradiant Energy Services[c]		
Kristin Shanon	Poseidon Saltwater Systems[c]		
Mike Skoda	Neptune FS Global[c]		
James Welch	Veolia[d]		

Table 4-4. Produced Water Evaporation Workshop Participants January 17, 2018

Industry Representatives		OWRB Staff, Agencies, Study Partners, and Consultants	
Participant Name	Organization	Participant Name	Organization
Omer Zehavi	IDE Technologies[c]		

Location of the meeting: Oklahoma History Center 800 Nazih Zuhdi Dr, Oklahoma City, OK 73105 (Fischer Board Room)

[a] Mississippi Lime Operators

[b] STACK and SCOOP Production Area Operators

[c] Evaporation companies

[d] Midstream companies

The workshop consisted of seven technical presentations on produced water evaporation technologies provided by the following:

1) Fountain Quail Energy Services
2) Gradiant Energy Services
3) Logic Energy Solutions
4) Neptune FS Global
5) Poseidon Saltwater Systems
6) Purestream
7) Veolia

The presentations are posted on the OWRB's website at www.owrb.ok.gov/pwwg and are provided in Appendix A.[13]

Six of the seven technical presentations were based on evaporation using heat or similar energy-related systems. These six technologies performed the evaporation in contained vessels. Only one technology used a mist vaporizer in open air.

The energy-based, contained systems presented the advantage of reducing the potential for saline water to condense outside of the systems. This could reduce the potential impact to soil or groundwater around the facility. These evaporation systems typically do not discharge water and do not have the associated regulatory and technical challenges with a discharger. The biggest challenges may be the inherent physics (energy requirements to treat high salinity water) and economic challenges of using energy to evaporate water.

It is currently unclear whether the technology will be able to evaporate produced water competitively. The SCOOP production area disposal costs range from approximately $0.25 to $0.75/bbls (for commercial SWDs) and $0.06 to $0.2/bbls (for producer-owned SWDs) in the Mississippi Lime production area in early 2018. According to the PWWG Report (CH2M 2017), evaporation costs associated with energy-based systems were estimated to range from $1.66 to $1.79/bbls.

Mist or vaporizer technology has the advantage of requiring significantly less energy, since it is not adding heat to facilitate evaporation. The potential risk of saline condensation dropping on nearby soil is a concern that can be mitigated by covering the area with a large plastic liner.

During facilitated discussions, workshop participants stated that enhanced evaporation of produced water has had very limited use in the industry to date. The following determinations resulted from the workshop:

- The economics of oil and gas operations impact evaporation technology as a potential option. If disposal costs increase sufficiently, and reuse options become limited, evaporation could be the best disposal option available.

[13] The presentations are claims provided by manufacturers and have not been checked for validity.

- Industry and technology providers did not understand the environmental regulations and permitting framework for selling the evaporation by-product (salt).
- Evaporation technologies lack uniform performance standards.

Evaporation could be a viable option with limited scale and duration. Instead of year-round operation, evaporation technology could provide periodic relief for producers when produced water injection disposal opportunities have been limited due to seismic activity.

4.3 Pipeline Route

This Study evaluated the pipeline routing identified in the PWWG Report in more detail and sought to:

- Reduce the length of required piping while also locating the start and end points of the pipeline central to activity
- Reduce the number of tunnels required for roads, railroads, and creek crossings
- Reduce drastic topographical changes
- Minimize disturbance to ecologically and culturally sensitive areas, and avoid tribal and recreational areas

The transfer pipeline network and associated infrastructure were sized for two produced water production scenarios, 200,000 and 400,000 bpd, to test the pros and cons when considering economies of scale. Based on input from the operators who participated in the Produced Water Transfer Workshop, individual operators in the Mississippi Lime production area were producing 200,000 to 400,000 barrels of water per day (bwpd), so the total for the area should be far in excess of 1,000,000 bwpd. During the Workshop, the operators in STACK and SCOOP areas estimated the total freshwater sourced at estimated at 500,000 to 1,000,000 bwpd; even in a slow year, operators reported they would use at least 200,000 bwpd. This production volume assessment suggested that doubling the capacity of the pipeline to 400,000 bwpd was not unreasonable and still fell well within the supply and demand projections. The economics of the project could be optimized by sizing the pipeline as large as possible, yet small enough to operate near capacity.

The transfer pipeline route developed with the PWWG Report was further revised based on a review of the major and minor operators in both the Mississippi Lime and STACK production areas to identify start and end points that are centrally located to the heaviest activity by most operators. Rather than building a new gathering system to collect water from individual producing wells, the pipeline was revised so it could directly connect to operators' existing produced water gathering systems in the Mississippi Lime area. In addition, the pipeline was expanded into southern Blaine County, to centrally locate the end point of the pipeline near more active rigs that could potentially use the water. Based on these revisions, the final pipeline alignment plan began in Woods County and was routed southeast to the eastern corner of Blaine County, near the intersection with Kingfisher and Canadian Counties.

Once the start and end points were determined, the pipeline route was developed to avoid or minimize impacts to ecologically sensitive areas and other areas of concern, such as the following:

- Geologic fault lines
- Wetlands
- Waterfowl and migratory bird refuge areas
- State parks
- Wild and scenic rivers
- Hazardous sites
- Wildlife management areas

Figure 4-4 shows the preliminary transfer pipeline routing and associated infrastructure. Topography was also reviewed and incorporated into the pipeline routing assessment to minimize elevation changes. As

shown on Figure 4-5, the elevation along the pipeline route ranges 436 feet from a low of 1,156 feet to a high of 1,592 feet.

The transfer pipeline was sized for a maximum velocity of 7 feet per second (fps), and high-density polyethylene (HDPE) DR11 was selected as the pipe material, with a pressure rating of 200 pounds per square inch. It is assumed that the transfer pipeline will be buried below grade, and eight intermediate pump stations, spaced every 10 miles along the pipeline route, would be required to convey the water approximately 88 miles from Woods County to Blaine County.

A clean brine storage impoundment is assumed at the northern end of the transfer pipeline to collect and store treated produced water generated by the Mississippi Lime operators. A second clean brine storage impoundment is assumed at the southern end of the transfer pipeline to store the treated produced water prior to distribution to the STACK operators. The clean brine storage impoundment was sized to provide 25 percent more storage capacity than the capacity of the transfer pipeline.

It is assumed that the oil and gas operators will be responsible for treatment and transport to and from the clean brine impoundments. This could be accomplished through pipelines owned and operated by the oil and gas operators or by trucking.

Table 4-5 summarizes the basis of design assumptions, which are based on acceptable engineering principals.

Table 4-5. Basis of Design Assumptions

Design Element	200,000 bpd	400,000 bpd
Pipeline Total Length (feet)	463,510	463,510
Maximum Velocity (fps)	7	7
Pipe Material	HDPE DR11	HDPE DR11
Pipe Size (inches)	24	32
Number of Pump Stations	8	8
Number of Impoundments	2	2
Volume of Each Impoundment	250,000[a]	500,000[a]

[a] Sized for 25 percent more storage capacity

Both the storage impoundments and treatment are discussed in Sections 4.2.2 and 4.2.

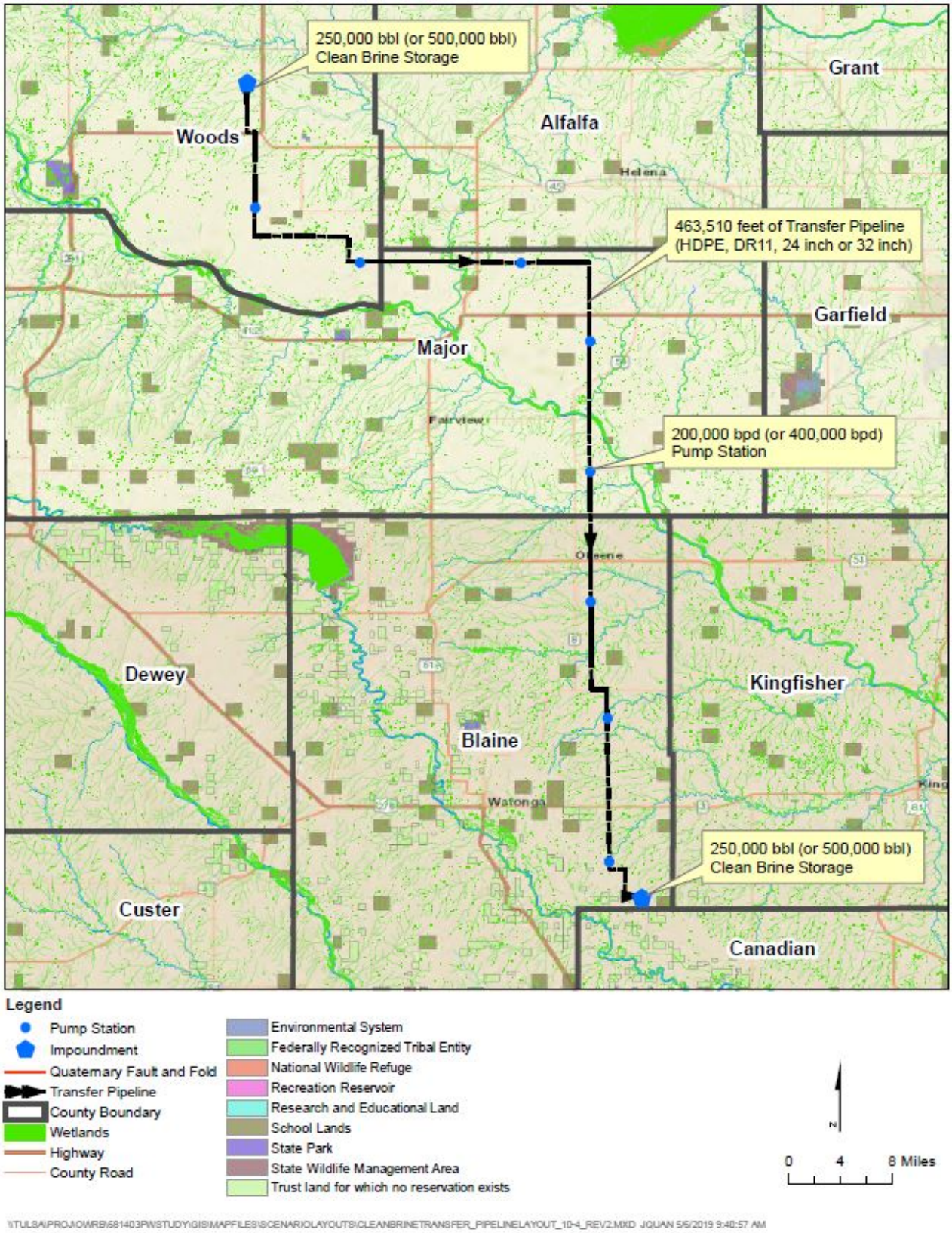
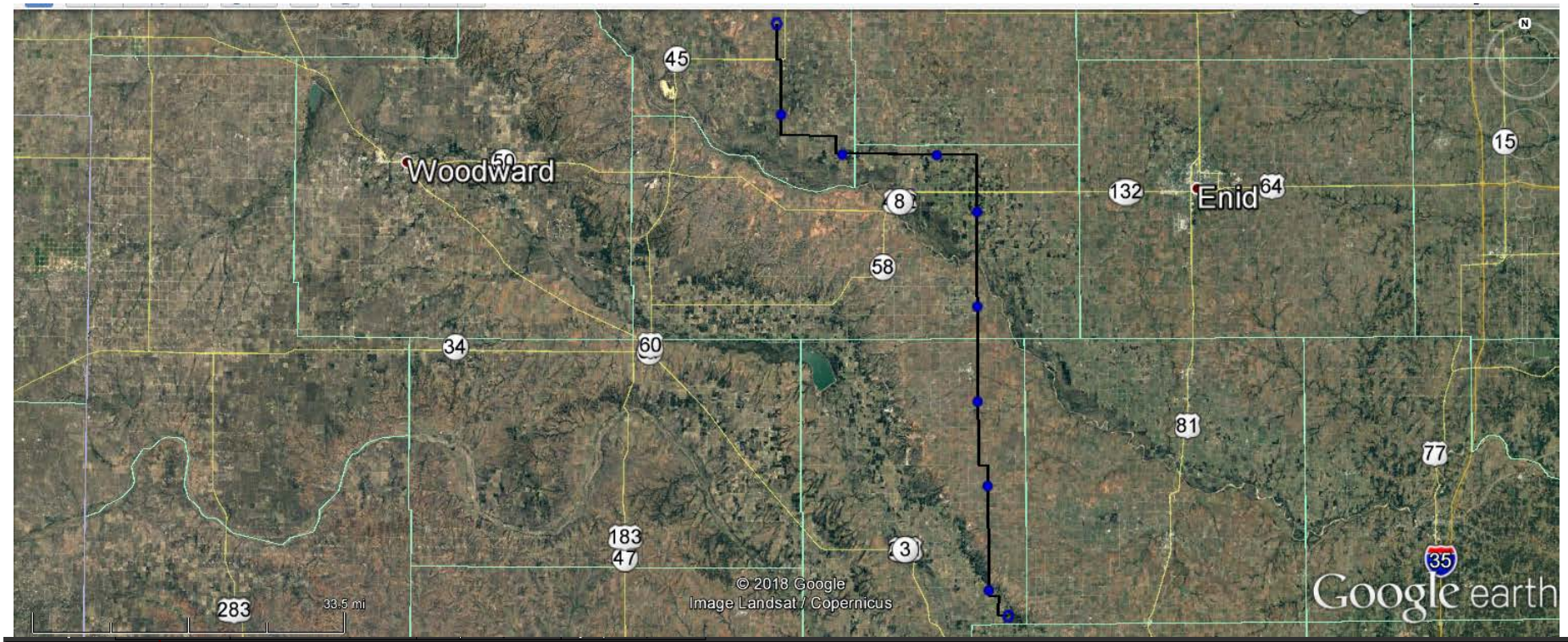


Figure 4-4. Proposed Produced Water Transfer Pipeline Alignment and Associated Infrastructure



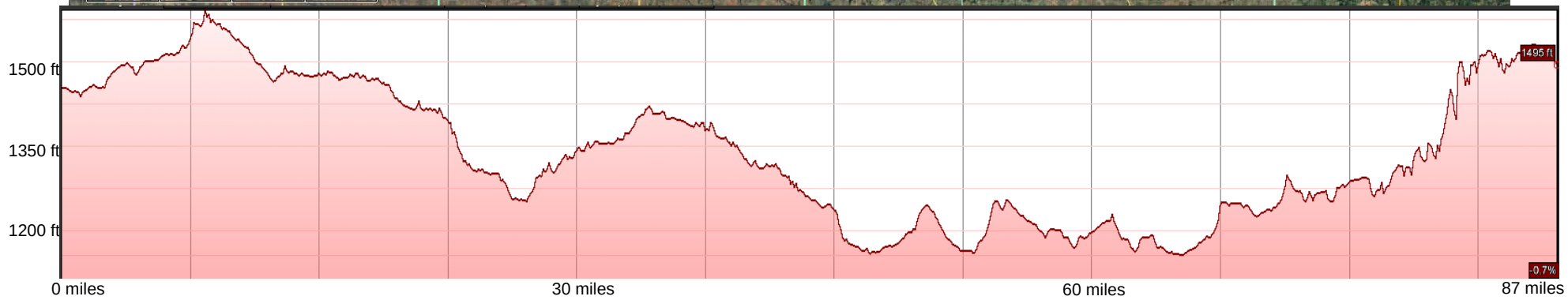


Figure 4-5. Proposed Water Transfer Pipeline Alignment and Profile

4.4 Treatment and Storage

4.4.1 Produced Water Treatment

Treatment of produced water for reuse has improved in recent years. Historically, it was thought that water had to be desalinated prior to reuse. However, within the last decade, producers have begun using a clean brine for hydraulic fracturing reuse, which is produced water after treatment for suspended solids, oil removal, and some reduction of the iron and hardness. Often, the treated water will be stored in an impoundment before a final treatment of bacteria at the well site. However, the amount of treatment varies by operator and is a function of the hydraulic fracturing chemistry and whether water is stored in an impoundment. The consistent theme is to only treat the produced water as needed. It may be worth noting that the treatment processes for produced water treatment for the use in oil and gas operations should not be confused with produced water treatment when the produced water is for example discharged into a stream or disposed by other means, such as evaporation or land application.

The suspended solids in produced water may be removed prior to its reuse if the operator decides the solids may impact the fluid stability, cause formation damage, or plug the fractures. High TSS water may require more additives to reduce friction. In many cases, producing companies will blend freshwater or brackish water to the produced water to reduce the TSS in the mixture and potentially allow its use without adding additional friction reducers.

Scale can be formed through the mixing of water with different geochemistries or if the acidity of the water changes. The formation of scale is a concern because it can build up in pipes, pumps, and impoundments. Scale clean-out is an additional operational cost and may cause downtime, as well.

Water treatment using aeration in impoundments is common to reduce the growth of certain anaerobic bacteria, which can form H_2S gas. Impoundment aeration will likely be necessary to reduce solids from the pipeline transfer system and reduce the chance of H_2S gas in the water storage.

4.4.2 Produced Water Storage

Water storage is an integral part of most produced water reuse systems. In the 200,000-bpd scenario, the cost estimate includes a 250,000-bbls water impoundment on the northern end of the pipeline and an equivalent impoundment at the southern end of the pipeline. The 400,000-bpd case includes 500,000-bbls impoundments in the north and south. The impoundments allow balancing of the hourly and daily inflow and outflow of the pipeline. The storage also helps stabilize the system due to interruptions of supply, sales, or maintenance.

The impoundment design should follow Oklahoma regulatory specifications and industry best practices, which includes the following:

1) A dual lined impoundment with leak detection
2) The walls or berms of the storage would be constructed with low-grade slopes to support long-term integrity
3) System automation of the filling of the impoundment to prevent overfilling
4) Bird abatement measures; often noise is used to keep birds out of the saline water, as netting is difficult to install over large impoundments

4.5 Cost Evaluation

The transfer pipeline and associated infrastructure were sized for two scenarios, 200,000 and 400,000 bpd, to develop conceptual cost estimates for comparison. The cost evaluation includes the following major components:

- Two, 250,000-bpd or two 500,000-bpd clean brine storage impoundments with truck offloading and filling stations
- Eight pump stations to transfer the water from Woods to Blaine County
- 88 miles of 24-inch or 32-inch HDPE DR11 transfer pipeline (sized based on a velocity of 7 fps)
- Three major creek crossings, and six highway or major road crossings
- Contingency and allowances for land, permitting, environmental, archaeology studies and mitigation, engineering, services during construction, startup, and commissioning

The total capital cost for the 200,000-bpd scenario is approximately $329,000,000. For the 400,000-bpd scenario, the capital cost is $462,000,000. A summary of the key cost elements is included in Table 4-6.

Table 4-6. Conceptual Cost Estimates for Two Produced Water Production Scenarios

Cost Element	200,000 bpd	400,000 bpd	Comments
Total capital cost, $ million	329	462	
Average throughput, bpd	180,000	360,000	Assumes 90% usage
Project life (economic assumption), years	10	10	
Operating Costs, cents/bbls[a]	52	45	
Discount rate: future barrels and costs, %/year	10	10	
Current Day Cost, $/bbls	1.21	0.93	

[a] Operating costs include water treatment, pumping, and maintenance.

The future barrels and future costs are discounted using a 10 percent factor. This is done to normalize the upfront capital cost, with operating costs spread through the project life, and to provide a current day cost. Using the 10 percent discounting of costs and barrels, the current day cost for the 200,000-bpd case is $1.21/BW and $0.93/BW for the 400,000-bpd case**.** These average costs per barrel are compared to the sourcing cost in the STACK and SCOOP production areas, plus the disposal cost in the Mississippi Lime area, for a total of $0.56 to $0.70/BW ($0.50/BW for freshwater in the STACK and SCOOP areas and $0.06 to $0.20/BW for disposal of produced water in operator-owned SWDs in the Mississippi Lime area). These costs could be higher by an additional $1.00 to $3.00/BW if trucking is required for either sourcing or disposal.

4.6 Implementation Considerations

In addition to the costs, other factors to consider regarding reusing produced water include the following:

- Risks
- Permitting and regulatory authorizations
- Future operating costs
- Other challenges that may be unique to each produced water reuse project

Significant considerations are identified in this section.

4.6.1 Risks

While some of the risks associated with produced water transfer are site-specific, the Study Partners identified five main risk categories associated with produced water transfer, as follows:

1) Technical: Infrastructure needs and sizing, water quality and treatment, supply and demand considerations, operations
2) Environmental: Wildlife, water bodies, and sensitive ecosystems
3) Regulatory and Legislative: ROW easements, water ownership, liability, and permitting
4) Financial: Unanticipated infrastructure, market predictions, and funding issues
5) Stakeholder and Political: Public perception, land use, local and regional relationships, political priorities

In future efforts that assess pipeline transfer of produced water, each risk category should be assessed in detail, and mitigation strategies should be developed, along with the implementation plan.

The results of the risk identification associated with produced water transfer through a pipeline are presented in Table 4-7. The key implementation risks and considerations and some potential mitigation measures associated with the produced water transfer through a pipeline include the following:

- **High water disposal costs in the Mississippi Lime**. The average produced water disposal cost currently is $0.06 to $0.20/bbls. Operators who participated in the Produced Water Transfer Workshop indicated that if the cost to dispose of produced water increased by $0.05/bbls, it may make some producing wells uneconomic, and they would have to be shut in. This is a significant concern to the producers in the northern counties, as the Mississippi Lime wells produce large volumes of produced water, with most of the produced water disposed of into SWDs.
- **Water quality.** The produced water from the Mississippi Lime production area is substantially higher in TDS than the STACK or SCOOP water. The associated concerns include: (1) Mississippi Lime water could negatively impact oil and gas production in the STACK operations due to water quality differences; (2) pure Mississippi Lime water could not be used without dilution or increased hydraulic fracturing chemicals; and (3) the mixed waters in the pipeline could create scale, or solids or H_2S gas in the impoundments. Mitigation of risks likely could include water treatment and aeration of impoundments.
- **Environmental impacts.** Spills and leaks from a large high salinity pipeline would be environmentally harmful. To mitigate or minimize such impacts, leak detection, instantaneous metering, automated isolation valves, and other monitoring systems should be utilized. In addition, clearly defined monitoring and permitting guidelines would need to be defined for the pipeline, including siting, construction, water crossings, and operations.
- **Balancing water supply and demand**. Increasing the economic efficiency and the operational feasibility of the pipeline could include sizing the pipeline capacity so that the pipeline could operate at near capacity most of the time. However, in case oil prices fell drastically and therefore causing STACK production to cease, it would impact the ability to recover the capital cost of the water transfer pipeline and other infrastructure.
- **Produced water ownership**. The lack of regulation and definition of ownership may lead to unintended consequences between the different parties of interest. Undefined ownership leaves open the question of considerations, such as royalty payments or environmental liability. To alleviate the potential regulatory uncertainty and lessen the potential for liability and ownership environmental impacts, the permitting and regulatory authorities should be clearly defined.
- **ROW**. The pipeline could potentially be classified as a common carrier that could allow eminent domain. The pipeline costs presented include an estimate for ROW costs, but these costs have uncertainty and are generally trending up.
- **Labeling or classifying the water**. The definition of produced water as either a waste or product may impact how the water is regulated or have other legal implications.

Table 4-7. Produced Water Transfer Risk Identification

Risk Category	No.	Risk and Consequence Description	
		Potential Risk or Uncertainty	Potential Consequence
Technical	1	Water supply management considerations, including matching supply and demand	Large volumes of water stored onsite increasing a risk of spills and leaks, maintenance needs and O&M costs.
			Challenge in optimizing the size of infrastructure to match supplies and demands: optimal sizing of pipeline to keep utilization high.
	2	Variations in source water quality and inconsistent water quality	Inability to determine treatment needs due to inconsistent water quality due to blended waters from third-party SWDs. Solids management, scale formation, or H_2S formation in impoundment
			Scaling of infrastructure and other operational challenges.
	3	Remote and widespread production locations	Unreliable water distribution to the demand side, lack of efficient system to deliver water to the frac sites.
	4	Insufficient leak detection and monitoring	Spills and leaks could interrupt operations and cause cost increases to operations.
Environmental	5	Spills and leaks from conveyance and storage infrastructure due to materials selections, handling, construction, operations	Contamination of soils and water sources, including aquatic ecosystems such as floodplains, wetlands, water crossings.
			Adverse impacts to human health.
	6	Produced water quality uncertainty or toxicity	Unknown constituents, especially NORM or chemical additives used in fracking, may cause challenges in spill response, routine monitoring and early detection.
			Remedial and corrective actions are not adequate to restore sites.
	7	Methods of pipeline construction	Open-trench construction could impact landscape, and water bodies and crossings.
	8	Operations in earthquake-prone areas	Pipeline failure or rupture could cause contamination.
	9	Large volumes of stored produced water onsite	Leaks and spills could cause soil and water sources contamination, and potential bird or wildlife impacts if produced water stored in open ponds.
Legal and Regulatory	10	Lack of existing jurisdiction and regulations about ownership of treated produced water; potentially overlapping and conflicting regulations	Value of water: conflicts if commoditizing produced water for other beneficial uses.
			Undefined liability, costs, and responsibility.
	11	Labeling or classifying produced water.	The definition of produced water as either a waste or product may impact how the water is regulated or have other legal implications.
			Unknown clean-up standards and requirements, and post-closure obligations: incorrect corrective actions could be implemented during operations or closure of operations that can cause environmental and human health impacts.

Table 4-7. Produced Water Transfer Risk Identification

Risk Category	No.	Risk and Consequence Description	
		Potential Risk or Uncertainty	Potential Consequence
	12	Infrastructure siting and operations requirements	Proximity of produced water conveyance to human and natural resources (residences, water bodies and water resources, farms, livestock, roads, railroads, environmentally or culturally sensitive areas, abandoned wells) can cause environmental and human health impacts, perceived or actual deterioration of landscapes and communities.
	13	ROW easement requirements below or above ground	Competing interests of oil and gas operator and landownership: right of access to property, including pipeline and auxiliary produced water infrastructure, may need negotiating and could delay the project and add costs to the project.
			Different types of requirements for temporary and construction ROW easements could add costs and time to the project.
			Permitting is complex and differs by county.
Financial	14	High cost of produced water projects due to high cost of water treatment, storage, and conveyance costs	Capital payback period is long, with uncertain rate of returns, thus causing diminished economic incentives to develop produced water market.
	15	Cost and uncertainty of obtaining ROW easements	Obtaining ROW agreements in an effort to secure pipeline pathway add to total costs.
	16	Third-party pipeline and operators alone invest on produced water reuse infrastructure	Potential loss of investment due to lack of commitment from produced water users and customers.
	17	Incorrect pipeline sizing due to discrepancy in supplies and demand	Can prohibit optimal utilization of pipeline capacity and therefore causes slower payback to the financier.
	18	Project economics are highly subject due to fluctuating oil and gas market conditions	Risks associated with investing in long-term assets, such as produced water treatment, storage and pipeline.
Stakeholder and Political	19	Produced water is not adequately understood by the public	Uncertainty about promoting produced water for other beneficial uses.
			NIMBY concerns, including aesthetics, safety, and hazards.
	20	Political and policy priorities change	Discontinued or diminished political support and funding to promote produced water.

Notes:
NIMBY = not in my backyard; a person who objects to the siting of something perceived as unpleasant or potentially dangerous in their own neighborhood
O&M = operations and maintenance

4.6.2 Regulatory Considerations

The current specific regulatory considerations are identified in Table 4-8, which includes the list of potential permits and authorizations, along with the lead agency. Specific OCC regulatory considerations associated with produced water reuse are included in Appendix C (Title 165: Corporation Commission Chapter 10: Oil and Gas Conservation).

Table 4-8. Permits and Authorizations, Produced Water Transfer through a Pipeline Project

Permit or Authorization	Granting Agency
Pipeline: Utility permit for federal or state highways	ODOT
Commercial recycling facilities: construction, operation and closure	OCC
ROW agreements for ROWs and easements: differ by county	ODOT, County, and OCC
Construction permits	OCC and ODEQ
CWA Section 404 Permit (if impacts to wetlands or jurisdictional waters of the United States)	USACE
National Environmental Policy Act (if federal nexus: funds, land, permitting)	USACE
Archeological survey	State Historical Preservation Office

Notes:

CWA = Clean Water Act

ODOT = Oklahoma Department of Transportation

USACE = U.S. Army Corps Engineers

4.6.3 Implementation Schedule

The implementation schedule is dependent on many variables and unknowns and could vary significantly depending on the durations required to develop agreements with operators and obtain permits. The agreements with operators would consist of financial agreements and contracts between the owner of the transfer pipeline, operators in the Mississippi Lime area to provide produced water, and operators in the STACK area to use the produced water for hydraulic fracturing. Once the agreements are in place, design of the infrastructure can begin. After determination of the best route for the pipeline and prior to finalization of the design, ROW agreements and environmental permits must be obtained.

It assumed that developing agreements with operators would take 4 months. Design could be started concurrently and would last approximately 12 months with 30, 60, and 90 percent design submittals and bid documents prepared. Permitting could begin after 30 percent design. A duration of 8 months was allocated to permitting and will depend on the final pipeline route chosen. Conveyance and facility construction would last approximately 12 months. The startup and commissioning time is assumed to be between 8 to 12 months. Table 4-9 provides potential implementation schedule.

Table 4-9. Implementation Schedule

Activity	Months									
	4	8	12	16	20	24	28	32	36	40
Agreements with Operators										
Design (30%, 60%, 90%, 100%)										
Bidding Services										
Permitting and ROW Agreements										
Conveyance and Facility Construction										
Startup and Commissioning										

4.6.4 Other Considerations

It is important to be aware that there has been, and remains, controversy in Oklahoma among county commissioners, their constituents, and oil and gas operators over non-freshwater lines within the easements, especially those using temporary (layflat) lines, and the question of surety of operator responsibility for any spills or leaks that may occur. The Oklahoma State Supreme Court recently ruled that OCC has exclusive jurisdiction over oil and gas activities, including authority to require reparations for any spills or damages that might occur from such temporary lines. ROW remains the subject of proposed legislation at the Oklahoma State Capitol.

The OCC has adopted rules that require a company using temporary lines to transport water that may contain produced water to provide at least 48-hour notice to the OCC Oil and Gas Conservation Division, county commissioners, and the surface owners of the land that is subject to the ROWs sought to be used by the operator, prior to placing temporary pipelines in public road ROWs that may at any time be used to transport produced water for well drilling, completion, or remedial workover operations (Form 5000NTL to provide the notice). Appendix C provides more details.

4.7 Produced Water Transfer through Pipeline Findings, Next Steps and Feasibility

Findings from the evaluation of the produced water transfer pipeline can be summarized as follows:

- The revised transfer pipeline and associated infrastructure is estimated to cost $1.21/BW (200,000 bpd) and $0.93/BW (400,000 bpd), as compared to the $1.01/BW (200,000 bpd) estimated in the PWWG Report. The change in cost is due to further refinement of the pipeline alignment and associated infrastructure from the 2017 study.
- $0.93 to $1.21/BW for the transfer pipeline is compared to $0.56 to $0.70/BW for sourcing costs in the STACK and disposal costs in the Mississippi Lime. An additional $1.00 to $3.00/BW would be added to the sourcing and disposal costs if trucking is used for sourcing or disposal. Most produced water is transferred via pipeline to operator-owned SWDs in the Mississippi Lime area as reported by operators; however, trucking is used in the STACK areas for freshwater sourcing.
- There is more produced water in the Mississippi Lime than water needed for hydraulic fracturing in the STACK.
- The pipeline route crosses many ecologically sensitive areas, county boundaries, highways and roads, and creeks. Further evaluation of the pipeline design and routing is required.
- A conceptual-level design package needs to be developed, including plan and profile drawings. Additionally, a hydraulic analysis of the transfer pipeline system should be performed to further refine the pipeline material, pipeline diameters, maximum system pressure, and maximum water velocity.
- The cost evaluation identified that while the capital cost is greater, construction of the larger-capacity system is more economical from a bwpd perspective.
- There are several risks associated with transfer of produced water. Each risk category identified should be assessed further, including mitigation strategies and implementation plans.

To mitigate impacts and develop strategies to facilitate produced water use in Oklahoma's oil and gas operations, the following subsections discuss the next steps and the potential roles of different entities in advancing produced water reuse.

4.7.1 Role of State Agencies

State officials from the OWRB, ODEQ, OCC, and Office of the Secretary of Energy should maintain contact with producing companies and industry groups to monitor for water sourcing limitations in central Oklahoma (especially Blaine, Kingfisher, and Canadian Counties). If the cost of water sourcing begins to approach $1/bbls, the transfer pipeline may be viable. State agencies can play a positive role in creating

a water transfer solution by bringing together producers from the two areas and water midstream companies that might invest in the project.

State agencies can also help by clarifying the regulatory and permitting processes, and by playing an active role in the project development. The agencies could also help with the classification of the water when it is sold, treated, and moved to another area for reuse. Regulatory predictability at the state level would also help local permitting entities streamline their land use planning and permitting processes. The OCC and ODEQ should clarify how spills will be regulated and handled by the agencies.

Overall, a key consideration for regulatory bodies will be clearly defining roles and jurisdictions related to produced water as early as possible, then moving to develop or modify the regulatory programs necessary to implement transfer and reuse. In this process, regulatory agencies should communicate with a variety of potential stakeholders and interest groups so that they are all informed and given the opportunity to be involved. Collaboration can help to identify potentially unforeseen risks or challenges and help to more efficiently move toward improved programs.

4.7.2 Producing and Midstream Companies' Risk Mitigation

As the risk identification and characterization show, the produced water transfer via pipeline has several uncertainties. Specifically, to reduce vulnerabilities to midstream companies, the mitigation measures of the risks can be identified and implemented in the short- (0-5 years), medium- (5-10 years), and long-terms (+10 years).

Mitigation measures identified during the Water Transfer Workshop include the following:

1) The companies could have a third party engaged to perform a benchmarking study on disposal costs in the Mississippi Lime and sourcing costs in the STACK. These costs could be compared to this Study's project normalized capital and operating costs per barrel (short-term).
2) The companies could conduct formation core studies to determine whether the Mississippi Lime water would have an impact on the STACK formation. They could also reconsider other potential water quality concerns (short-term).
3) Companies can collaborate to evaluate leak detection, instantaneous metering, automated isolation valves, and other best practices to mitigate spill risk (short- and long-terms).
4) The companies could update the balance of water evaluation between how much is projected to be available in the north and how much is projected to be needed in the south. The pipeline owner would benefit from this knowledge to size the pipeline appropriately (short- and long-terms).
5) Produced water ownership is likely best resolved by legislation that clarifies how this critical issue is handled. Companies could work through industry groups to suggest solutions to state legislators (short- and mid-term).
6) The potential owner of the pipeline will need to perform a detailed ROW assessment before agreements with producing companies are signed. The option of a common carrier designation could be explored (short-term).
7) The companies could work with the agencies to help evaluate the classification of the water treated and transferred for reuse and its potential implications (short-term).

4.7.3 Pilot Project

For future planning, profiling certain oil and gas production areas for possible reuse of produced water reuse zones (for example, under state regulations) could provide an opportunity to explore produced water use as a pilot project. This may include developing more focused regulations and obtaining public input, which could provide industry more predictability and enable companies to make long-term plans for water-sharing and reuse.

5. Evaporation

Parts of Oklahoma have high volumes of produced water disposal that has been linked to induced seismicity (CH2M 2017). The alternative to deep well disposal addressed as part of this Study includes produced water evaporation. Evaporation and enhanced evaporation are used synonymously in this report. Enhanced evaporation means to evaporate freshwater from high salinity produced water by using a process that is faster than natural evaporation. Natural evaporation is not considered viable for the purposes of this Study due to the large surface area required to evaporate the significant quantities of produced water.

There are two main categories of enhanced evaporation used by water treatment companies. The most common is to use heat to evaporate the water in a specially designed vessel. Six of seven companies invited to present their technologies at an Evaporation Workshop (Section 1) used heat as the evaporation method. One evaporation company had technology that vaporizes the produced water into the air as a fine mist, which allowed evaporation to occur at ambient conditions. In all cases, companies would pretreat the water to remove impurities, including suspended solids and residual oil.

Figure 5-1 shows the stages of getting produced water to enhanced evaporation facility, from the producing wells to oil, gas, and water separation; and then to storage, to an evaporation facility, and the by-products from the evaporation.

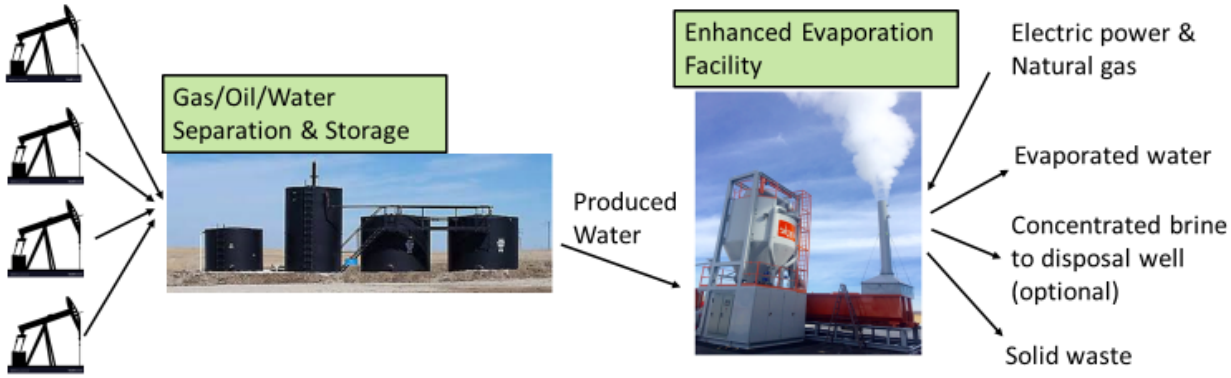


Figure 5-1. Enhanced Evaporation Flow Diagram

With most technologies, the evaporation process can either create a saturated brine or a zero-liquid discharge. In all cases, solids are generated. A saturated brine means that the dissolved solids reach a limit, usually around 300,000 mg/L, when the solids drop out of solution with more evaporation. Zero-liquid discharge means that all water is evaporated and only solids remain after the total evaporation of the water. The solids contain sodium chloride, as well as all of the other dissolved solids in brine. However, if the process is stopped at a saturated brine, it is possible to limit the need to dispose of solids, as the saturated brine can be injected into a disposal well. This methodology significantly reduces the volume of water, depending on the initial saturation of the brine.

If the initial brine is 30,000 mg/L TDS, typical of the STACK and SCOOP, and is concentrated to near saturation at 300,000 mg/L, nearly 90 percent of the produced water can be evaporated without precipitating most of the dissolved solids. Alternately, the Mississippi Lime may be 200,000 mg/L TDS initially. In this case, only about 33 percent of the water can be evaporated before the concentrate is near saturation at 300,000 mg/L TDS. Thus, the Mississippi Lime will need to be reduced to nearly zero-liquid discharge to eliminate a significant percentage of the produced water prior to deep well disposal. It will also create substantial volumes of solids that will have to be disposed or sold or used for other applications (road salt or other industrial uses).

The following subsections describe the evaporation technologies, including a comparison of different evaporation technologies by each design consideration (Table 5-1), such as the following:

- Water recovered for potential reuse
- Unit's mobility potential
- Air quality impacts
- Primary energy source
- Relative energy demands
- Potential waste product(s)
- Applicable waste product disposal methods (deep well injection or landfill type)

Table 5-2 summarizes advantages and disadvantages for each technology, including the following:

- Relative magnitude of cost (high, medium, or low by gross qualitative estimation) of the technologies
- Legal and regulatory constraints
- Residuals management
- Environmental considerations
- Potential stakeholder or political limitations

Table 5-3 lists the overall risks associated with produced water evaporation.

5.1 Evaporation Technology Overview

Evaporation processes encompass a wide range of technologies. For the purposes of this Study, broad technology categories were established to distinguish evaporation approaches for comparing design advantages and disadvantages. These categories are as follows:

- Evaporation ponds
- Mechanically enhanced evaporation ponds
- Modular thermal evaporation with or without water recovery
- Traditional thermal evaporation with water recovery

Each technology category could include multiple configurations, depending on the treatment goals and available vendor technology limitations. Brief overviews of each technology category are outlined in the following subsections[14].

5.1.1 Evaporation Ponds

Produced water is placed in large ponds where the water is eliminated over time through atmospheric evaporation. As the water evaporates, some salts precipitate and form solids that settle in the pond. The settled solids reduce the capacity of the ponds and require periodic clean out and disposal. Salts with high solubility, such as chloride, will concentrate in the remaining water and cause the evaporation rate (rate of water lost to the atmosphere) to decrease, eventually to a low percentage of the initial evaporation rate. At this point, it is inefficient for additional water to be managed in the pond. The pond would be taken out of service to allow the brine solution time to slowly evaporate and to remove the precipitated solids. Ponds are typically constructed with a flexible membrane liner to prevent leakage of produced water.

The benefit of this technology is that, depending on land requirements, it typically has lower capital and operating costs. It requires very little mechanical equipment beyond conveyance systems to transfer the produced water to the pond. A disadvantage compared to thermal evaporators or crystallizer systems is that ponds do not offer a ready means to capture the evaporated water for possible reuse. The technology also cannot not be mobilized, meaning that water would need to be transported to a fixed evaporation pond location. The space required to evaporate the large volumes of water from oilfield operations is generally not practical. Where evaporation ponds have been employed, it has been for particular locations with limited water production.

[14] Although the report delimits between manufacturer claims and peer-reviewed scientific data through the case studies, the readers should be aware that, for some technologies/processes, manufacturer brochures were the only available source for information.

Transporting produced water may be challenging, depending on the volume and distance; it also carries the risk of accidental spills or leaks from either pipelines or trucks. Large impoundments could generate public relation issues due to visibility and environmental impact concerns, such as groundwater or wildlife impacts.

Evaporation ponds can also be used for brine management from evaporative technologies, as opposed to deep well injection or crystallization. The land requirements would likely be significantly smaller than evaporation ponds treating the entire flow. Aside from land purchases, the capital costs are highly variable and are frequently on the order of millions to tens of millions of dollars (depending on wastewater flow and quality). If existing pond is available, costs can be less. Additional evaluation should be conducted to determine the economic feasibility of this technology based on the produced water volumes of oil and gas operations. Also, the next steps should assess the produced water quality and location of the pond (local evaporation rates and rainfall impact the pond sizes).

5.1.2 Mechanically Enhanced Evaporation Ponds

A variation to the passive evaporation pond design is to add mechanical aspirators or sprayers to enhance evaporation. These mechanical enhancements spray water droplets into the air, which increases evaporation rates and either decreases the pond size requirements or increases throughput of the evaporation ponds. While this variation is more energy intensive than passive evaporation ponds, the electrical requirements and operating costs are generally orders of magnitude lower than thermal evaporators or crystallizers.

Disadvantages to mechanically enhanced evaporation ponds are similar to passive evaporation ponds. These systems do provide a ready means to capture the evaporated water for potential reuse and cannot be mobilized, requiring produced water be transported to the pond system for treatment. Large impoundments are highly visible and may lead to public concerns. Additionally, mechanically enhanced ponds include unique risks, primarily particulate drift from the sprays to the surrounding areas, which can cause environmental impacts and public perception issues, also from noise can impact nearby communities. In some cases, the salinity from the water can cause corrosion and paint discoloration to nearby houses or negative impacts to vegetation. The mechanical nozzles can also be prone to scaling, depending on the water composition, particularly salinity.

Unlike evaporation ponds, this configuration would likely not be able to manage brine wastewater from other evaporative technologies due to scaling at higher TDS concentrations. Disregarding land purchases, the capital costs are frequently on the order of millions to tens of millions of dollars (depending on wastewater flow and quality).

5.1.3 Modular Thermal Evaporators with Water Recovery

Thermal evaporation can be used to remove dissolved salts from produced water, while recovering low TDS distillate for potential reuse (if water recovery is a goal). It generates a high TDS concentrate or brine stream for disposal or further concentration into a salt cake. Modular thermal evaporators are smaller, single-vessel systems. Depending on the vendor system, these evaporators can employ a combination of mechanical vapor compression (MVC), steam, and alternative heat energy sources, such as NG or propane. Configurations without water recovery may directly spray the produced water into an evaporation vessel using NG or propane to evaporate the water; in these configurations, the produced water is directed into a firing system burning the fuel source, and the combination of exhaust gas and water vapor is sent out a stack. The viability of one configuration over others may be driven by available energy supply, produced water volumes, and water recovery targets.

Evaporated water can either be condensed for possible reuse or discharged to the atmosphere via a stack. Depending on the water composition and vendor equipment performance limitations, the disposal products may include brine, crystallized salt cake, or both. Brine can be disposed in a deep well injection system or evaporation pond. Transportation of the brine to a disposal location has the risk of accidental release. Crystallized salts would need to be landfilled; further evaluation would determine whether they could be placed in a *Resource Conservation and Recovery Act* (*RCRA*) Subtitle D versus Subtitle C landfill.

The primary advantage of modular technology is its mobility, avoiding the need to transport produced water for treatment or potential evaporate reuse (if water recovery is selected). Evaporating water to the atmosphere could require more extensive air permitting requirements than recovering water.

The equipment typically has lower capital costs than traditional (non-modular) evaporators; some vendors offer rental options rather than purchasing. The design capacity will be a large factor of the cost, as most available units have, relative to other technologies, low capacities. Flow capacities vary by vendor and can range from less than 5,000 bpd to approximately 10,000 bpd. Given energy requirements, operating costs will be higher than evaporation ponds, but conceptual analysis on a case-by-case basis would be needed to compare costs to traditional thermal evaporation systems, as modular units are often less energy efficient and could require multiple units to treat the entire flow. Capital costs are largely driven by the wastewater flow and quality, which impacts the number of units needed. Generally, capital costs are on the order of tens of millions of dollars.

5.1.4 Traditional Thermal Evaporators or Crystallizers with Water Recovery

Traditional thermal evaporators and crystallizers are more complex systems and usually have larger capacity than modular evaporators. The evaporation mechanism is similar, using MVC, steam, or both for heat to evaporate produced water, while recovering distillate for reuse and generating a high TDS brine or crystallized salt cake (or both) for disposal. Common configurations include falling-film, MVC evaporators, and force-circulation evaporators. Falling-film and MVC evaporators typically have better thermal efficiency than force-circulation evaporators, which, while typically having lower thermal efficiency, also have lower scaling risks. Depending on the water chemistry, a system may use chemical softening to adjust the water chemistry to remove scaling ions prior to evaporation.

The primary advantages of this technology are its robustness and thermal efficiency. There are several mechanical elements that can be adjusted to improve operability and performance of the technology in response to changes in incoming water quality and flow conditions, lending to a more robust technology. The downside is this typically requires additional labor dedicated to monitoring, controlling and maintaining the system operations. One reason for its thermal efficiency is capturing and reusing heat from the hot distillate; therefore, this technology is typically not configured to evaporate to the atmosphere. These traditional technologies have much higher flow capacities than modular systems.

The disadvantages of these systems include the lack of mobility and its cost. This technology is likely to have the highest capital costs of all systems considered here; operating costs will also be high, given the energy demands and labor requirements, as this technology typically requires additional labor dedicated to monitoring, controlling, and maintaining system operations. Capital costs are largely driven by the wastewater flow and quality; generally, capital costs are on the order of tens of millions to more than a hundred million dollars.

An evaporator alone will likely produce a brine for disposal, whereas a crystallizer could evaporate enough water so that the only waste product is a salt cake. Since this technology is fixed to a given treatment location, ideally, it would include adjacent disposal options (deep well injection system or landfill) to avoid risks from transporting the waste material, particularly the brine.

5.1.5 Reverse Osmosis Pretreatment Configuration with Evaporative Technologies

Volume reduction can be achieved by pairing reverse osmosis (RO) with most of the evaporative technologies presented. The RO system may produce a permeate for potential reuse, while sending the brine reject to a given evaporative technology. Mechanically enhanced evaporation pond systems may not be viable with a RO system, as the brine reject could cause issues with mechanical spray equipment. Generally, RO systems treat wastewaters with up to 25,000 to 35,000 mg/L TDS and can achieve up to approximately 80,000 mg/L in the brine reject. The approximate 35,000-mg/L TDS limit for RO is important, since most produced water is significantly higher in TDS. Central Oklahoma in the STACK and SCOOP area have produced water that is lower than average. Per the PWWG Report, the counties in the center part of state have produced water TDS ranging from 10,000 to 30,000 mg/L.

Assuming that an RO system could achieve reasonable water recovery, the system could decrease the size of ponds, evaporators, or crystallizers. Capital and operating costs may or may not be reduced, depending on the complexity of the RO system and projected membrane lifespan. It will add complexity to the operation of any system it is paired with and may require additional pretreatment, as well. For these

reasons, RO has been removed from the technology category comparisons but could be considered for conceptual evaluations (see Next Step Recommendations).

Depending on the water chemistry, pretreatment technologies could improve the performance or size requirements for evaporation technologies. A few examples are dissolved gas flotation (oil removal), chemical precipitation (softening or organic removal), or electrochemical and electrocoagulation processes (alternative concentration process to RO). Similar to RO, these technologies would add operational complexity and could generate additional waste products (for example, sludge) that would need to be managed. Produced water characterization would be necessary to determine the need for, or applicability of, pretreatment technologies.

5.1.6 Technology Comparisons

Table 5-1 compares the technologies by each design consideration. One design component not considered here is the reuse options for the waste products. While some industries have found uses for evaporative waste products (that is, the solids residuals), there have been very limited reuses from produced water evaporation. A number of vendors treating produced water are hopeful to develop more products from the treatment solids, but these efforts would be highly dependent on the wastewater characteristics (which dictate waste product quality and characteristics) and viable markets (driven by locations, market demand, and alternative supplies).

Table 5-1. Comparison of Design Considerations by Technology

Evaporation Technology	Water Recovered for Potential Reuse	Mobile	Potential for Air Quality Impacts	Primary Energy Source (NG, Electricity)	Relative Energy Demands	Potential Waste Products (Brine, Salt Cake)	Applicable Waste Product Disposal Methods		
							Deep Well Injection	Subtitle D Landfill	Subtitle C Landfill
Evaporation Pond	No	No	Moderate	None	Low	Brine and Salt Cake	No	Dredged Solids	Dredged Solids
Enhanced Evaporation (Evaporation Pond with Mechanical Spray	No	No	High	Electricity	Low	Brine and Salt Cake	No	Dredged Solids	Dredged Solids
Modular Thermal Evaporator[a] Vented to the Atmosphere	No	No	Moderate	NG[b]	High	Brine, Salt Cake, or both	TBD	TBD	TBD
Modular Thermal Evaporator[a] with Water Recovery[c]	Yes	No	Low	NG[b]	High	Brine, Salt Cake, or both	TBD	TBD	TBD
Traditional Thermal Evaporator or Crystallizer [a] with Water Recovery [c]	Yes	No	Low	Electricity[a]	High	Brine, Salt Cake, or both	TBD	TBD	TBD

[a] Evaporators have multiple configurations (examples include forced circulation, multi-stage effect, MVC, or a combination), each with advantages or disadvantages. This applies to crystallizers, as well. Flow and water quality information is often needed to adequately compare these technologies or develop cost estimates; therefore, this table focuses on generalizations based on mobility and clean water production.

[b] Typical, but alternative energy sources may be used or offered by vendors.

[c] Water recovery for evaporation technologies can be greatly impacted by the TDS composition of the produced water. In general, higher TDS concentrations will have lower water recovery, and lower TDS will have higher water recoveries.

Note:

TBD = to be determined

As shown in Tables 5-1 and 5-2, the current list of technologies varies in terms of water recovery, mobility, waste disposal, legal and regulatory constraints, and operating cost ranges.

Figures 5-2 through 5-9 show different types of evaporation technologies.

Figure 5-2. Fountain Quail's NOMAD Mechanical Vapor Recompression Mobile Evaporator

Figure 5-3. Gradient's Carrier Gas Extraction Unit

Figure 5-4. Logic ES Submerged Combustion Evaporator

Figure 5-5. Fisk Neptune Evaporator

Figure 5-6. Poseidon's Evaporation Facility Near Enid, Oklahoma (during construction)

Figure 5-7. Poseidon Saltwater Systems Vaporizer System

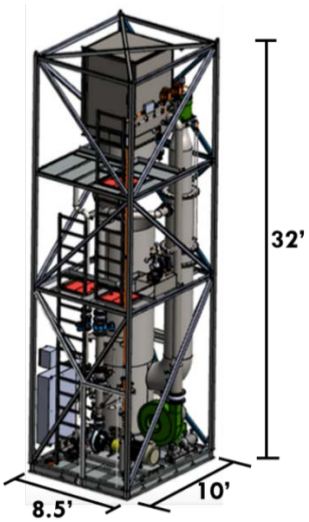


Figure 5-8. Purestream's Flash Unit Evaporator

Figure 5-9. Veolia MBD Evaporator Being Installed

5.2 Implementation Considerations

Factors to consider regarding implementation of produced water evaporation include the following:

- Permitting and regulatory authorizations
- Land acquisition
- Future operating costs
- By-product and residuals management
- Other challenges that may be unique to each project

Significant considerations are identified in this section. Also, the Study Team investigated other states' produced water regulatory frameworks.

Table 5-2 provides a comparison of implementation considerations associated with the main types of evaporation technologies. The main considerations are as follows:

- Residuals management
- Environmental
- Stakeholder/political
- Financial (relative magnitude of cost: high, medium, low by gross qualitative estimation)

The following design considerations for each technology were considered:

- Water recovery: Determine if the technology will produce a reusable water or if it evaporates (disposes) water to the atmosphere
- Mobility: Consider whether technologies can be relocated to locations requiring wastewater treatment as opposed to having to have the wastewater trucked or pumped to fixed locations
- Air quality impacts: Identify technologies that could impact air quality
- Primary energy source: Identify energy sources used for water evaporation; all technologies will require some electrical source to operate mechanical components, such as pumps
- Energy demand: Differentiate relative energy demands (high, medium, low) for each technology
- Waste products and disposal: Describe the types of residual waste products, including concentrated brine and crystallized salt cake; the technology or configuration, along with the water characteristics, will dictate the applicable disposal method of waste products, which may include deep well injection (brine) or either *RCRA* Subtitle D versus Subtitle C landfill (driven primarily by the wastewater characteristics)

Table 5-2. Summary of Evaporation Technology Implementation Considerations

Technology	Residuals Management	Environmental	Stakeholder and Political	Financial
1. Evaporation Pond	• Settled solids and precipitated salts need to be disposed (dredge and landfill). • There is a lack of quality-controlled products. • Mixed salt residue has low value and limited uses (salt cake produced will be a combination of multiple salts e.g. CaSO4, NaCl). • Case-specific evaluation would be needed to determine whether beneficial reuse of waste products is possible.	• Surface impacts include footprint, spills leaks. • Potential environmental risk to surface water and groundwater. • Potential wildlife and migratory bird hazard. • Air quality impacts. • Soils contamination. • Would not reduce demands for freshwater supplies (no water recovery), but would reduce volume of water disposed in deep well injection systems. • Large land requirements. • Would need to transport water to the system, which carries the environmental risks of accidental release of produced water and more vehicle traffic if trucked. • Moderate energy requirements.	• Large footprint. • Requires trucking or pipeline transportation to a centralized facility.	• Ignoring land purchases, generally on the order of are millions to tens of millions of dollars (depending on wastewater flow and quality). • Water chemistry and other factors will dictate the magnitude of operating costs and solids removal frequency, especially relative to other technologies.
2. Enhanced Evaporation	• Settled solids and precipitated salts need to be disposed (dredge and landfill). • Case-specific evaluation would be needed to determine whether beneficial reuse of waste products is possible.	• Would not reduce demands of freshwater supplies (no water recovery), but would reduce volume of water disposed in deep well injection systems. • Drift from the spray application may create environmental or public relations issues with the surrounding area. • Large land requirements. • Would need to transport water to the system, which carries the environmental risks of accidental release of produced water and more vehicle traffic if trucked. • Potential environmental risk to groundwater and surface water. • Moderate energy requirements. • Potential wildlife and migratory bird hazard.	• Requires trucking or pipeline transportation to a centralized facility.	• Ignoring land purchases, generally on the order of tens of millions of dollars (depending on wastewater flow and quality). • Water chemistry and other factors will dictate the magnitude of operating costs and solids removal frequency, especially relative to other technologies.

Table 5-2. Summary of Evaporation Technology Implementation Considerations

Technology	Residuals Management	Environmental	Stakeholder and Political	Financial
3. Modular Evaporation Vented to the Atmosphere	• Residuals may include high TDS brine and crystallized salts, depending on water chemistry. • Brine could be disposed of in a deep well injection system or evaporation pond for final disposal. • Crystallized salts would need to be landfilled. • While not a "residual," the water vapor would need to be vented from a permitted stack. • Case-specific evaluation would be needed to determine whether beneficial reuse of waste products is possible.	• Would not reduce demands for freshwater supplies (no water recovery) but would reduce volume of water disposed in deep well injection systems. • Could be relocated as needed to the produced water production location, avoiding having to transport this water. • Would likely need to transport waste residuals offsite, which carries environmental risks associated with transport (particularly for brines). • Crystallized salts, if achievable, would avoid disposal options with negative environmental impacts (deep well injection, evaporation pond). • Energy intensive.	• Requires trucking or pipeline transportation to a centralized facility.	• On the order tens of millions of dollars (depending on wastewater flow and quality). • Leased modular equipment or supplier provided and operated systems may be available at a cost of $2 to $2.5/bbls operating cost (CH2M 2017). • Water chemistry and other factors will dictate the magnitude of operating costs, especially relative to other technologies
4. Modular Evaporation with Water Recovery	• Residuals may include high TDS brine and crystallized salts, depending on water chemistry. • Brine could be disposed of in a deep well injection system or evaporation pond. • Crystallized salts would need to be landfilled. • Case-specific evaluation would be needed to determine whether beneficial reuse of waste products is possible.	• Would reduce demands for freshwater supplies (produces low TDS water for reuse) and would reduce volume of water disposed in deep well injection systems. • Could be relocated as needed to the produced water production location, avoiding having to transport this water. • Would likely need to transport waste residuals offsite, which carries environmental risks associated with transport (particularly for brines). • Crystallized salts, if achievable, would avoid disposal options with negative environmental impacts (deep well injection, evaporation pond). • Energy intensive.	• Steam cloud could cause stakeholder concerns.	• On the order of tens of millions of dollars (depending on wastewater flow and quality). Leased modular equipment or supplier provided and operated systems may be available on a $3 to $6/bbls operating cost (CH2M 2017). • Water chemistry, water recovery targets, and other factors will dictate the magnitude of operating costs, especially relative to other technologies.

Table 5-2. Summary of Evaporation Technology Implementation Considerations

Technology	Residuals Management	Environmental	Stakeholder and Political	Financial
5. Traditional Evaporator or Crystallizer with Water Recovery	• Residuals may include high TDS brine and crystallized salts, depending on water chemistry. • Brine could be disposed of in a deep well injection system or evaporation pond. • Crystallized salts would need to be landfilled. • Case-specific evaluation would be needed to determine whether beneficial reuse of waste products is possible.	• Would reduce demands for freshwater supplies (produces low TDS water for reuse) and would reduce volume of water disposed in deep well injection systems. • May be able to contain waste streams onsite, reducing the environmental risks associated with transport (particularly for brines). • Would need to transport water to the system, which carries environmental risk of accidental release of produced water and more vehicle traffic if trucked. Additional transport may be required for low TDS distillate. • Crystallized salts, if achievable, would avoid disposal options with negative environmental impacts (deep well injection, evaporation pond). • Energy intensive. • If chemical pretreatment is required, it could produce large quantities of chemical sludge that would also need to be disposed.	• Steam cloud could cause stakeholder concerns.	• On the order of tens of millions to more than a hundred million dollars (depending on wastewater flow and quality). • Water chemistry, water recovery targets, and other factors will dictate the magnitude of operating costs, especially relative to other technologies.

5.2.1 Risks

In addition to the comparison of implementation considerations associated with the main types of evaporation technologies, the overall evaporation risks were identified by the Study Partners. While some of the risks associated with produced water evaporation are site- or technology-specific, the Study Team identified five main risk categories associated with produced water evaporation.

The five main risk categories are as follows:

1. Technical: Infrastructure and chemicals needed for treatment, infrastructure efficiencies, weather impacts on operations, overall footprint of the facility, and residuals management
2. Environmental: Potential air emissions, by-product reuse safety, overspray, disposal of salts in landfills or injecting, spills and leaks, energy needs, wildlife impacts, and trucking of water
3. Regulatory and Legislative: Siting, monitoring and reporting requirements, regulatory guidelines on overall operations, and solids and residuals resale and management
4. Financial: O&M costs, operations flexibility and scalability, and ability to sell evaporation by-products
5. Stakeholder and Political: Public perception, by-product resale, health effects, facility impacts on landscape, potential spills and leaks, and trucking impacts of influent

In the future analysis of produced water evaporation, each risk should be assessed in enough detail so that an implementation plan and potential strategies to mitigate the risks can be developed.

Table 5-3 presents a summary of the risk identification associated with main types of produced water evaporation technologies.

Table 5-3. Permits and Authorizations, Produced Water Evaporation Project

Permit or Authorization	Granting Agency
Commercial evaporation facilities: Construction, operation and closure	OCC

Table 5-4 summarizes the identified risks.

Table 5-4. Produced Water Evaporation Risk Identification

Risk Category	No.	Risk and Consequence Description	
		Risk or Uncertainty	Potential Consequence
Technical	1	Varying chemistry of produced water, which is location dependent; no single technology will fit all situations	Unknown pre- and post-treatment of feed water requirements impact type of technology needed and system design
			Types of chemicals required for treatment
			Inability to treat blended waters
			Loss of evaporation efficiency or increased brine concentrations (reduced recovery rates)
			If solids removal frequency increases, additional disposal of solids needed
	2	Weather limits use with overspray, as rain and wind stop the process; weather impacts efficiency	Accumulation of produced water onsite and problems for producing companies relying on evaporation of their produced water
	3	Significant infrastructure commitments	Permanent and large footprint; reliance on specific type of energy (e.g., steam)
	4	Still an emerging technology and scale (full-scale, pilot-scale, bench-scale)	Uncertainty about treatment reliability
Environmental	5	Air emissions	Air quality violations, including hazardous emissions and VOCs
			Odor problems
	6	Unknown by-product reuse safety	Distilled water safety, including oil and grease, microorganisms, and radioactive elements
			Unknown characterization of salt or other solids for reuse
	7	Concentrate waste management	NORM or heavy metals disposal to landfill
			Crystalized salts would need to be disposed (landfilled) if not sold for reuse
			Deep well injection of salts and brine can cause earthquakes
			Transportation offsite for disposal
			High volumes and concentrations of salt could saturate the markets or landfills
	8	Spills and leaks	Soil and water contamination
	9	Evaporation ponds attract wildlife to feed and nest	Toxicity to wildlife
	10	Overall large carbon footprint due to high energy needs	Need natural gas or electrical power onsite
	11	Trucking or pipeline transportation to a centralized evaporation facility	Air emission, traffic volumes, spills, noise
	12	Blow-over or transport of salts and solids to surrounding land	Soil contamination
	13	Unknown clean-up standards and requirements and post-closure obligations	Remedial and corrective actions are not adequate to restore sites for closure

Table 5-4. Produced Water Evaporation Risk Identification

Risk Category	No.	Risk and Consequence Description	
		Risk or Uncertainty	Potential Consequence
	14	Does not reduce freshwater demands (no water recovery)	Not a freshwater conservation measure; evaporation only solves part of the water needs but alleviates disposal needs
Regulatory and Legislative	15	Monitoring of overspray and mist transportation offsite from enhanced evaporation	Soil contamination
	16	Limited guidance and regulations for siting of facilities and operations	Delay getting permit approval
	17	Limited clean-up standards and requirements and post-closure obligations	Unclear or incorrect corrective actions during operations or operations closure
	18	Unknown by-product reuse safety	Lack of standards and permits for reuse of salt
Financial	19	Concentrate management and waste disposal can be a major cost component	Limited available disposal options
			Increased trucking
	20	High O&M costs	Cost increases with limited expected life cycle of process and high replacement needs
			Some technologies require highly skilled labor for monitoring and control
			High TDS concentrations increase treatment costs, including chemical costs
			Cost structure not scaled based on TDS concentrations
	21	Limited flexibility and scalability	Storage capacity needs (impoundments, tanks)
			Treatment
	22	Mixed salt residue has low value and limited use	Deters investment
	23	Large land acquisition costs	Deters investment
Stakeholder and Political	24	Steam and vapor	Visual impacts; aesthetics
	25	Requires solids trucking offsite	Impacts rural roads and landscape, causes interference and conflicts with existing land uses (e.g., farming, recreation, wilderness), and noise and air quality concerns
	26	Use of by-products	Economic benefits may be offset by potential environmental risks
	27	NIMBY concerns, including facilities' invasive footprint, aesthetics	Impacts landscape, causes interference and conflicts with existing land uses (e.g., farming, recreation, wilderness)

The key implementation risks and considerations and some potential mitigation measures associated with the produced water evaporation include environmental risks and regulatory considerations.

5.2.1.1 Environmental Risks

One of the potential benefits for stakeholders of enhanced evaporation is that it reduces the amount of water injected underground for disposal. This would likely be a driver to implementation in an area where disposal costs have risen due to high demand and limited disposal capacity. In this scenario, enhanced evaporation could also be the better option for the producing company trying to find outlets for the produced water. But there are also several environmental considerations with enhanced evaporation.

Carry-over of High Salinity Water

The most acute risk is that evaporated mist or steam has some carry-over of produced water constituents outside of the confines of the operation. The saline mist is evaporated at ambient conditions, while a more concentrated brine is retained at the surface of the liner below the mister. The challenge is to have a liner extending far enough to account for the changes in wind speed and humidity, which will cause the travel range of the saline mist to vary. Any carry-over of the high-salinity water could cause built up salt and other minerals in the soil, which is harmful to the environment. Remediation of salt in soil is difficult and expensive. Usually, the soil has to be removed at a significant cost to the environment and to the responsible entity.

A system that monitors the salinity of the discharged mist or steam could reduce the risk of carry-over of saline water. Periodic soil testing could be performed in the area around the facility to monitor impacts.

Evaporation in vessels is inherently less likely to cause overspray.

Solid Waste

With full evaporation or crystallization, or zero-liquid discharge, a significant volume of solids is generated due to the high salinity. There are financial costs and environmental risks associated with the solids. Typically, a solid waste, like waste from water treatment, would be hauled to a landfill by truck. Trucking and storage of produced water solids introduces a variety of environmental hazards, including the following:

- Long-term risk of salt impacts to groundwater from storage of salts in a landfill
- Potential for hazardous concentrations of NORM
- Increased impact of truck traffic on roads and potential for salt spills
- Air emissions from increased truck traffic

The storage of millions of tons of salts in landfills adds a long-term risk. One treatment company reported approximately 270 tons of solids per 10,000 bbls of water desalinated for 175,000 TDS water quality. A truck can haul about 20 tons per trip. If salt water leaks from the landfill at any time in the future, it could risk contaminating groundwater. Because the salt does not degrade, the risk remains indefinitely.

Selling or reusing the solids from produced water was discussed by most of the water treatment companies at the Enhanced Evaporation Workshop. This option for solids management is largely unproven. If the additional cost to transport the solids to a new facility (instead of a landfill) is less than the price paid, then selling solids could be viable. It is not clear that the market for industrial salts could use all of the salt generated by the volume of water that could need to be evaporated.

NORM is not uncommon in oilfield operations. When produced water is treated, especially with desalination, any radioactive elements are much more concentrated in solids than in the water. Best practices are to monitor for NORM in water treatment operations. The disposal of NORM solids must be done in a special landfill and increases the cost and potential transportation hazards.

Other Environmental Risks

Methanol is often injected at the producing well site in NG operations to prevent water vapor from freezing during the winter months. In at least one case in Pennsylvania and West Virginia, enough methanol was released at water treatment facilities that the treatment process had to be stopped. Generally, methanol use is less common in warmer climates, but warrants monitoring. According to the Centers for Disease Control (CDC), methanol can be absorbed into the body by inhalation, ingestion, skin contact, or eye contact. The health effects of methanol exposure may include neurological, gastrointestinal, ophthalmological, and other effects (CDC 2019). One company reported extensive emissions testing of their system. Methanol was 0.0034 pound per hour, or 0.41 percent of the methanol was released from the facility.

VOCs are compounds that easily become vapors or gases. VOCs are released from burning fuel, such as gasoline, wood, coal, or natural gas. VOCs may be generated from the combustion of NG at a water treatment (evaporation) site or may be a constituent in produced water. Best practices include monitoring VOCs at the evaporation site, even if they are not expected to be a concern. According to the U.S. Environmental Protection Agency (EPA), VOCs may cause eye, nose and throat irritation, headaches, and damage to the nervous system and are suspected to cause cancer (EPA 2019).

5.2.2 Regulatory Considerations

The current permitting requirements identified in Table 5-3 includes a list of potential permits and authorizations, along with the lead agency. Specific OCC regulatory considerations associated with produced water evaporation are included in Appendix C.

The speed of obtaining approvals could become an important aspect of advancing the evaporation option. If oil prices fall suddenly and reuse of produced water falls in tandem, the need for evaporation could occur within a matter of months. Since few evaporation facilities have been permitted so far in Oklahoma, the process is still new for regulators and applicants. Thus, there could be urgency for action in this new regulatory area. Advance work by the OCC to clarify the process could help if there will be a sudden volume of applications with the next oil price decline.

Another regulatory consideration is whether a mobile facility could be given a permit to operate state-wide. The mobile facility could be given a general permit subject to a review of the next planned location. This approach could effectively permit the technology and process, but still be subject to the regulatory agency approving the actual location.

Residuals from treated brine must be disposed of as a liquid via SWD or meet the specifications of local landfills. Operators wanting their own SWD will need to seek appropriate permits from OCC. Operators must complete a nonhazardous declaration of the proposed facility's by-product with the landfills, as well as get transportation permits as appropriate.

There is a potential for airborne drift beyond the facility of fine mists of produced water in the forced evaporation process and other such technologies; hence, soil sampling or other monitoring may be required in the permit for some determined distance beyond facility boundaries (OAC 165:10).

5.2.2.1 Other States' Evaporation Regulatory Experience

The Study Partners explored other states' regulatory frameworks and experience with produced water evaporation. They contacted the oil and gas regulatory agencies in Alabama, Arkansas, Nebraska, Ohio, and Utah. These states have had evaporation operations in the past. The consensus was that, although the technology was feasible, there were issues with either the feasibility of its use in the state or additional concerns with mitigation that needed to be addressed in the pilot projects performed. Of the states surveyed, Utah had the most comprehensive program in place. The GWPC, a Study Partner, contacted

state regulatory entities in five different states that regulate produced water evaporation in their states, to learn about their produced water evaporation permitting and regulatory frameworks.

- Alabama Oil and Gas Board and Ohio Division of Oil & Gas Resources Management: No proposals or applications have been made for use of the technology. They do not believe weather conditions would be favorable in the state.
- Arkansas Oil and Gas Commission and Nebraska Oil and Gas Conservation Commission: Each had one pilot test attempted in their state. Arkansas' weather conditions were not favorable for the technology. Both Arkansas and Nebraska expressed concerns about particulates being carried offsite during operations. The technology is no longer being explored in the either state.
- Utah Division of Oil, Gas and Mining: The state does have an involved permitting process for use of evaporation technology. Facilities are restricted from being placed in floodplains, drainages, or any area deemed unsuitable based on geology. Inspection and reporting are performed to maintain compliance to permits issued for the facility, and a full plan for reclamation must be submitted to the state. There are an estimated 15 active facilities in the state, with up to of 30 in the past. Through the life of the facilities, new technologies have been introduced to enhance evaporation, oil separation, and emissions control.

None of the oil and gas regulatory agencies contacted regrading evaporation had specific regulations on evaporation by-products. Most of the companies presenting at the Study Workshop indicated that they believe that the solids from the treatment process have marketable value and could be sold for industrial uses. The value of the solids is not likely to materially offset treatment costs. The market for selling large volumes of sodium chloride and other solids from produced water is unproven, but there is potential. Desalination companies in the Appalachian production area of Pennsylvania and West Virginia are evaluating selling produced water solids from that region.

5.2.3 Other Considerations

The implementation schedule depends of the type of technology used. Stationary facilities' design, permitting, and construction of evaporation ponds could take months. Mobile facilities could be faster to construct. Permitting for discharge (for example, modular thermal evaporator with water recovery) have historically taken 1 to 2 years.

5.3 Produced Evaporation Findings, Next Steps and Feasibility

Findings from produced water enhanced evaporation feasibility evaluation include the following:

- Economic feasibility:
  - Cost of disposal versus cost of evaporation. Evaporation would be economically feasible when the combined cost of transporting produced water to a disposal well and disposal cost per barrel of water is higher than the cost of enhanced evaporation. In the PWWG Report, a survey of three evaporation vendors indicated a typical cost of approximately $1.75/bbls for 20,000 bpd of produced water (includes energy costs).
  - Production areas with a high water-to-oil ratio (for example, Mississippi Lime) may not be able to evaporate at $1.75/bbls of produced water due to increased transportation and treatment costs. However, a group of wells in the STACK or SCOOP with a more modest water-to-oil ratio may benefit economically from evaporation compared to the higher cost of injection disposal.
  - A group of wells or tank batteries could be connected to join a common pipeline to deliver the produced water to an evaporation facility, sharing infrastructure and reducing transportation costs.
- Considerations:
  - Potential high energy demand of evaporation technology. The evaporation company normally uses NG or electric power. Company estimates range from 0.4 to 0.5 thousand cubic feet of NG

per barrel. Energy costs of evaporation could be reduced if any gas that would otherwise be flared is used in the process.

- The required space for a vessel-based evaporation technology is minimal, approximately 100 feet by 100 feet. These are often skid-mounted mobile facilities. A mist spray system will require more space, perhaps 250 feet by 250 feet, for the pretreatment and the lined sprayer area. Additionally, the lined sprayer area would be more difficult to move from one area to another.
- Potential environmental impacts. The risk of produced water carryover into the steam or mist needs to be well controlled.
- Solids management for disposal and for reuse.

The next steps to further incentivize enhanced evaporation should include the following three:

1) Proactive approach for managing produced water under different economic conditions:
   - Producers, regulators, and treatment companies should monitor water disposal costs at commercial SWDs, especially in those areas that have large volumes of produced water or decreased capacity to inject produced water into disposal wells. If the disposal costs approach $1.50 to $2.00/bbls, opportunities for enhanced evaporation may be a more cost-effective alternative than disposal.
   - If oil prices decline and the hydraulic fracturing completion operations are suspended, any produced water that was being reused in the operations would need to be disposed. The increased demand for produced water disposal could increase disposal costs; thus, making evaporation a viable option.
2) To meet a potential increase in evaporation permit applications, regulators should consider standardizing and streamlining the current evaporation permitting protocol in an anticipation of large number of permit applications. In addition, permitting a mobile unit under a single permit and allowing the mobility of the unit independent of the location in the state (rather than needing a permit each time the mobile facility moves) should be considered by regulators to incentivize produced water evaporation.
3) A pilot study should be conducted to include regulatory changes and economics that could increase feasibility by addressing a number of considerations identified in this report, including:
   - Management of salts
   - Permitting
   - Shared infrastructure

6. Conclusions and Next Steps

6.1 Conclusions

6.1.1 General

In this this Feasibility Report, two produced water reuse and recycling alternatives were evaluated for two oil and gas production areas in Oklahoma: (1) produced water transfer from the Mississippi Lime production area to the STACK areas through a pipeline (200,000- and 400,000-bpd scenarios), and (2) evaporation of produced water in the Mississippi Lime production area. The evaluation produced the following five conclusions:

1) The greatest opportunity presently for reuse of produced water is within oil and gas operations. While this is already practiced within single operations, transferring water among operators and area could be increased. The chief constraints of transporting water between Mississippi Lime and STACK operations include the following:
   - Costs
   - The uncertainty surrounding the ownership and liability of produced water
   - The lifecycle of water in drilling operations, which results in highly variable supply in Mississippi Lime and demand in STACK and SCOOP
   - Market effects on drilling activity
   - Potential environmental impacts in both transporting and storing water
   - The physical and chemical properties of produced water from different formations, and stages and types of operations
   - Reuse may be impeded by delays in permitting and an uncertain regulatory environment
2) Enhanced evaporation allows excess produced water to be dealt with when reuse and disposal are already at their practical limits. This may occur if, or when, disposal is restricted by regulation, or if reuse is reduced due to limited drilling and hydraulic fracturing in the area. Cost and environmental factors are potential constraints to the growth of enhanced evaporation.
3) Either of the proposed scenarios could result in reduced disposal or injection of produced water into SWDs., which potentially reduces the risk of earthquakes associated with high injection volumes.
4) Produced water quality was studied in this feasibility report, since water quality is important to blending waters for reuse and for enhanced evaporation. The physical, chemical, and biological characteristics of produced water are not well documented, and there is a lack of publicly available data. To provide a comprehensive data set, this Study provides water analyses for eight samples from various formations in central Oklahoma.
5) The water quality sampling done as part of this Study suggests that produced water qualities vary substantially, even within a single county. While the sampling effort provides insight into the characteristics of the produced water from different formations, the scope was limited, and challenges associated with sample collection and analysis resulted in some of the data being unreliable.

6.1.2 Transfer Pipeline Feasibility

The nine primary conclusions related to the feasibility of the transfer pipeline are as follows:

1) The transfer pipeline was determined economically infeasible at this time. To justify the large investment risks associated with such a project, the estimated price points, at a minimum, must beat the current price for source and disposal in STACK and Mississippi Lime. This Study determined a range from $0.93 to $1.21/bbls for the 400,000- and 200,000-bpd scenarios, respectively, which does not meet the minimum threshold of $0.56 to $0.70/bbls.

2) The transfer pipeline could become more feasible if (1) a drought occurred in central Oklahoma or an increase in demand for source water for hydraulic fracturing in the STACK created more demand for produced water that the transfer pipe could bring; or (2) a significant seismic event occurred in Mississippi Lime area, and alternative disposal options were needed for this area. This driver is limited by the fact that the Mississippi Lime area has a modest upper limit on water disposal costs due to the high ratio of water to oil produced.
3) There is more produced water in the Mississippi Lime than water needed for hydraulic fracturing in the STACK.
4) The pipeline route crosses many ecologically sensitive areas, county boundaries, highways and roads, and creeks. Further evaluation of the pipeline design and routing is required.
5) A hydraulic analysis of the transfer pipeline system should be performed to further refine the pipeline material, pipeline diameters, maximum system pressure, and maximum water velocity.
6) The cost evaluation identified that while the capital cost is greater, construction of the larger-capacity system is more economical from a bwpd perspective.
7) For future planning, profiling certain oil and gas production areas for possible reuse of produced water reuse zones (for example, under state regulations) could provide an opportunity to explore produced water use as a pilot project. This may include developing more focused regulations and obtaining public input, which could provide industry more predictability and enable companies to make long-term plans for water-sharing and reuse.
8) The feasibility of implementing a transfer pipeline needs to address several risks, including:
   - The Mississippi Lime producers need assurance that the pipeline would represent a reliable way to export their produced water. But, the transfer of water is dependent on continued drilling and completion activity near the southern end of the system.
   - The STACK producers need assurances that they will be able to count on the pipeline to deliver water when they need it. A significant falloff of production in the north could impact the pipeline volumes transferred, but the proposed pipeline size mitigates this risk, since it is a fraction of the overall production in the Mississippi Lime area in the north.
   - Environmental factors related to the transfer of large volumes of high salinity produced water are significant. A total rupture of a 200,000- or 400,000-bpd produced water pipeline could have significant environmental impacts, even if the rupture were contained quickly. Although this risk can be somewhat mitigated by effective pipeline design, it would remain a significant factor to executing this project.
   - Some producers in the STACK have concerns that the water quality difference between the Mississippi Lime and STACK formations could have a negative impact on the producing well productivity. The Mississippi Lime formation averages around 200,000 mg/L of TDS; whereas, the STACK formations may average about 30,000 mg/L of TDS. If the water quality difference impacted well performance, it would be a substantial impediment. Mitigating this risk before the installation of the pipeline would be complex.
9) This Study has raised questions about the regulatory permitting and approval process of a pipeline of this magnitude. Since produced water pipelines of this length are rare, the implementation and operational regulations as well as permitting should be clarified.

6.1.3 Enhanced Evaporation Feasibility

The four primary conclusions related to enhanced evaporation are as follows:

1) There is currently enough disposal capacity in the STACK and SCOOP areas to meet current disposal needs. There is only one known enhanced evaporation facility operating in the area that accounts for a very small percentage of the overall water production.
2) Current water disposal in injection wells is lower cost that enhanced evaporation technologies, as demonstrated by having only one operating evaporation facility. However, disposal costs could

increase due to more produced water demand or due to potential restrictions of disposal from a local seismic event.

3) If or when enhanced evaporation becomes widely economically viable, the OCC could rather suddenly face numerous requests for permits for enhanced evaporation. The OCC should consider what steps could be taken today to prepare for the potential of numerous applications for evaporation facility permits.

4) Environmental risks are present with enhanced evaporation, primarily with the steam or mist leaving a facility, and with the potential for significant amounts of solids generated from the water processing.

6.1.4 Related Considerations

Two other important related conclusions are as follows:

1) Reuse of produced water in oil and gas operations continues to expand in Oklahoma based on public releases by a couple of the larger producing companies.

2) Water midstream companies have emerged that could bring solutions to water reuse by producing companies, including the potential for reuse through the transfer pipeline from one area of the state to another.

6.2 Next Steps

Next steps to advance the two produced water reuse and recycling alternatives include the following:

1) Determine the disposal and water sourcing influence on overall oil and gas production area economics.

2) Develop ‘what-if’ scenarios to optimize water transfers between Mississippi Lime and STACK production areas.

3) Assesses historical water production and water use trends in the Mississippi Lime production area to inform a water management strategy.

4) Develop a conceptual level design package, including plan and profile drawings; and perform a hydraulic analysis of the transfer pipeline system to further refine the pipeline material, pipeline diameters, maximum system pressure, and maximum water velocity.

5) Further characterize produced water quality and collaborate with oil and gas producers to share water quality information. Additional water quality data are required to confirm unreliable results from this sampling effort, such as TDS in the STACK produced water, and to supplement the data set collected for further analysis and evaluations discussed herein.

6) Conduct a scaling analysis to determine the scaling potential of the produced water and mixing of different formations’ waters. The mixing of different formations’ waters could potentially create scale precipitation and could create operational problems that may include solids buildup in pipelines, vessels, and pumps.

7) Perform a qualitative and quantitative evaluation of produced water spills and subsequent remediation needs.

8) Conduct core testing of formation core samples with the Mississippi Lime produced water. The water from Mississippi Lime could potentially negatively impact the performance of the new hydraulically fractured well where the reuse occurs. For the producing companies investing in explorations and operations, any measurable reduction in well performance due to water quality would be risky. This risk may be partially mitigated by performing minimal treatment of the water to be used in hydraulic fracturing.

9) Evaluate treatment requirements and costs. The effectiveness and costs of the water treatment processes are impacted by the produced water quality.

10) Conduct pilot testing of evaporation technologies to determine:
   - Whether overspray of produced water beyond the permitted evaporation site can result in soil and air contamination by certain key constituents.
   - What the key constituents of concern are in such operations; and what elevated levels measured, if any would be acceptable.
   - The amount and type of solids generated (including NORM) that are dependent on the produced water quality.
   - The potential for air emissions, such as VOCs.

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Appendix A
Produced Water External Stakeholder Workshop Presentations

Oklahoma Water Resources Board
PW Feasibility Study Group
Evaporation Workshop

Oklahoma History Center
Jan 17, 2018

Fountain Quail Energy Services
NOMAD and Modular Base Plant (MBP) Systems
Brent Halldorson, CTO

Agenda

1. NOMAD Evaporators
2. Modular Base Plants (MBPs)
3. Energy Use, %-Recovery
4. Oklahoma Issues
5. Zero Liquid Discharge

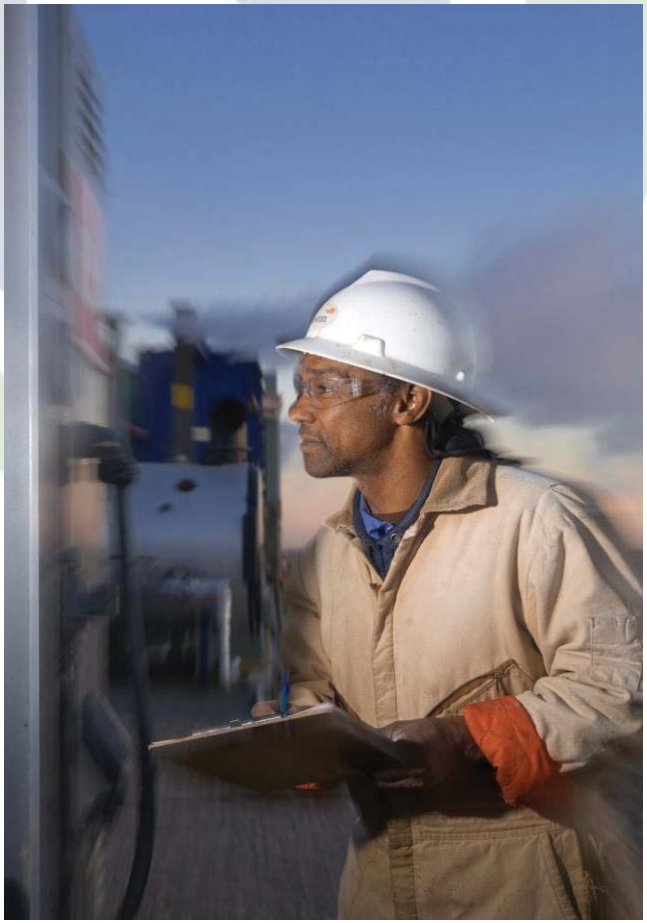
Fountain Quail Energy Services

Pioneers…

- ✓ Recognized leaders in North America.
- ✓ First commercial recycler in shale wastewater.
- ✓ First recycling permit in Texas.
- ✓ First to meet Pennsylvania discharge criteria (Marcellus Shale).
- ✓ First evaporator in Alberta heavy oil (SAGD).
- ✓ Founding members of Texas Water Recycling Association (www.txwra.org).
- ✓ Now over 350 employees (significant growth through downturn).

NOMAD Technology

Fountain Quail's patented evaporator technology overcomes challenges associated with oilfield wastewater recycling:

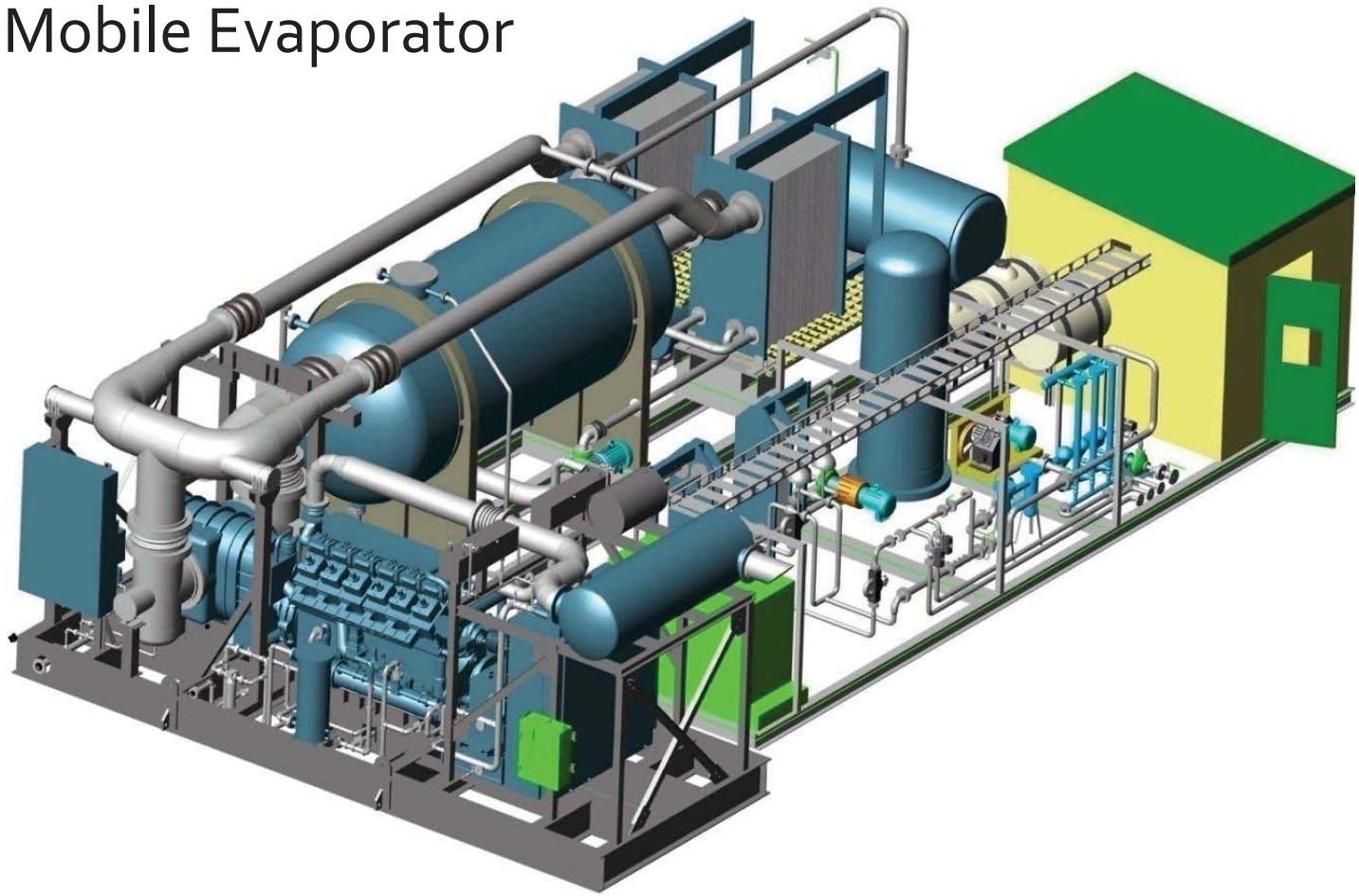


- ✓ Consistent, High Quality Distilled Water
- ✓ Compact, Low Height, Mobile
- ✓ High % Recovery
- ✓ Capable of Treating Highly Variable Wastewater
- ✓ Modular (low installed cost)
- ✓ High Energy Efficiency
- ✓ Reduced Fouling / Scaling
- ✓ Reliable and Serviceable

The Result:
NOMAD System

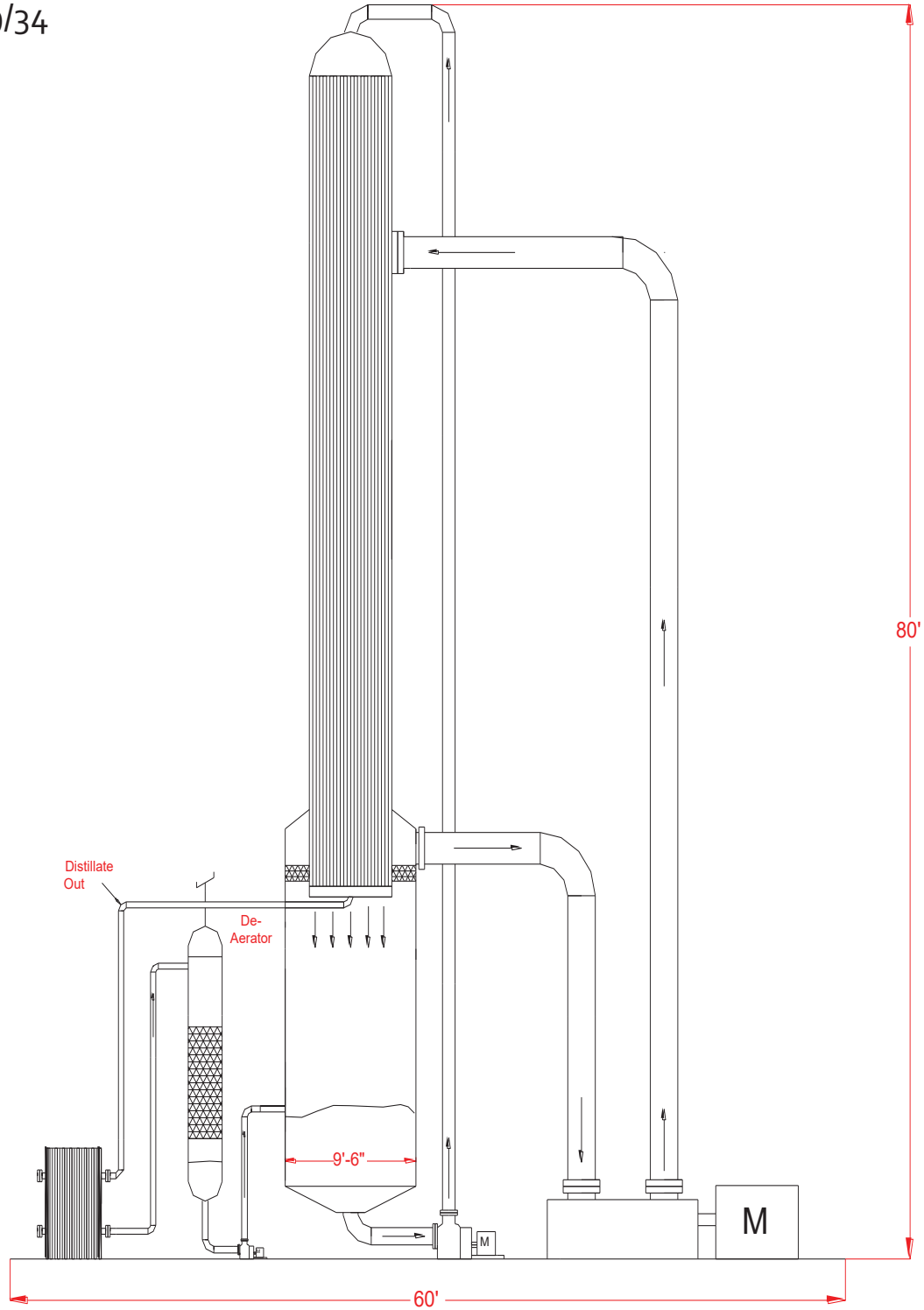
NOMAD Technology

Mobile Evaporator



- ✓ Patented & Proven.
- ✓ Only system with >15yrs continual service in upstream O&G.
- ✓ Capable of treating wide range of wastewater with high recovery (80-90%).

NOMAD Capacity: 2,000bbl/d distilled water

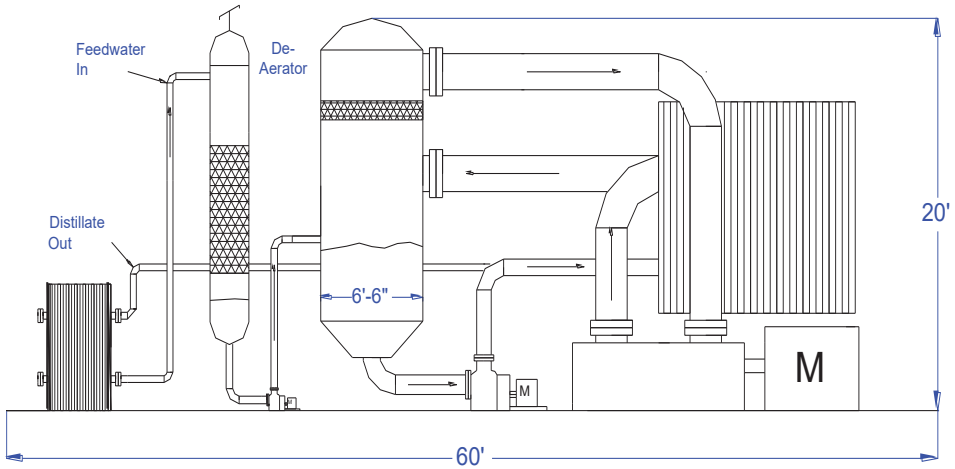


Traditional Falling Film Design:

- ☒ Higher Installed Cost
  - Large equipment, requires assembly on site.
- ☒ Higher Operating Cost
  - Less efficient, higher hp, more chemicals
- ☒ Difficult to Service

Fountain Quail Design:

- ☑ Compact
- ☑ Efficient
- ☑ Reliable & Serviceable



NOMAD Exchangers

- ✓ Counter-current heat transfer = more efficient than falling film (co-current).
- ✓ Easy to open and clean – ideal for oilfield PW.
- ✓ Fountain Quail excels in markets where traditional evaporators fail.

Recycled Distilled Water

High quality distilled water is ideal for re-use.

Suitable for irrigation, re-use or environmental discharge.

NOMAD Example 1
Barnett Shale Texas

NOMAD: The standard in generating freshwater from oil & gas produced water.

NOMAD Example 1
Barnett Shale Texas

Objectives:

- Generate freshwater for frac fluid. Direct to existing freshwater pit network.
- Use PW as source water – minimize use of ground/surface water.
- Re-use residual clean heavy brine (~9.8#) for well servicing.

NOMAD Example 1 Barnett Shale Texas

- Customer: Devon Energy
- Summary: Fountain Quail installed a total of 14 NOMAD™ sites.
- Timeframe: Nov 2004 – Dec 2013
- Volume Recycled: 20+ million bbls recycled back to freshwater.

NOMAD Example 2
Permian Basin, Texas

2 NOMAD™ site. Main power: natural gas.

NOMAD Example 3
Wolfcamp (Permian), Texas

2 NOMAD™ site
Wolfcamp (Permian)

TX Experience

- FQ had the 1st recycle permit in TX – intense scrutiny from regulators. Perfect track record.
- New RRC Recycle Rules allow distilled water from thermal evaporation to be handled as freshwater (if kept within oilfield).
- This is a **direct result of Fountain Quail NOMAD's track record** with the RRC over 10+ years of submitting water & air test results.

NOMAD Example 4
Marcellus Shale, Pennsylvania

Treatment for environmental discharge.

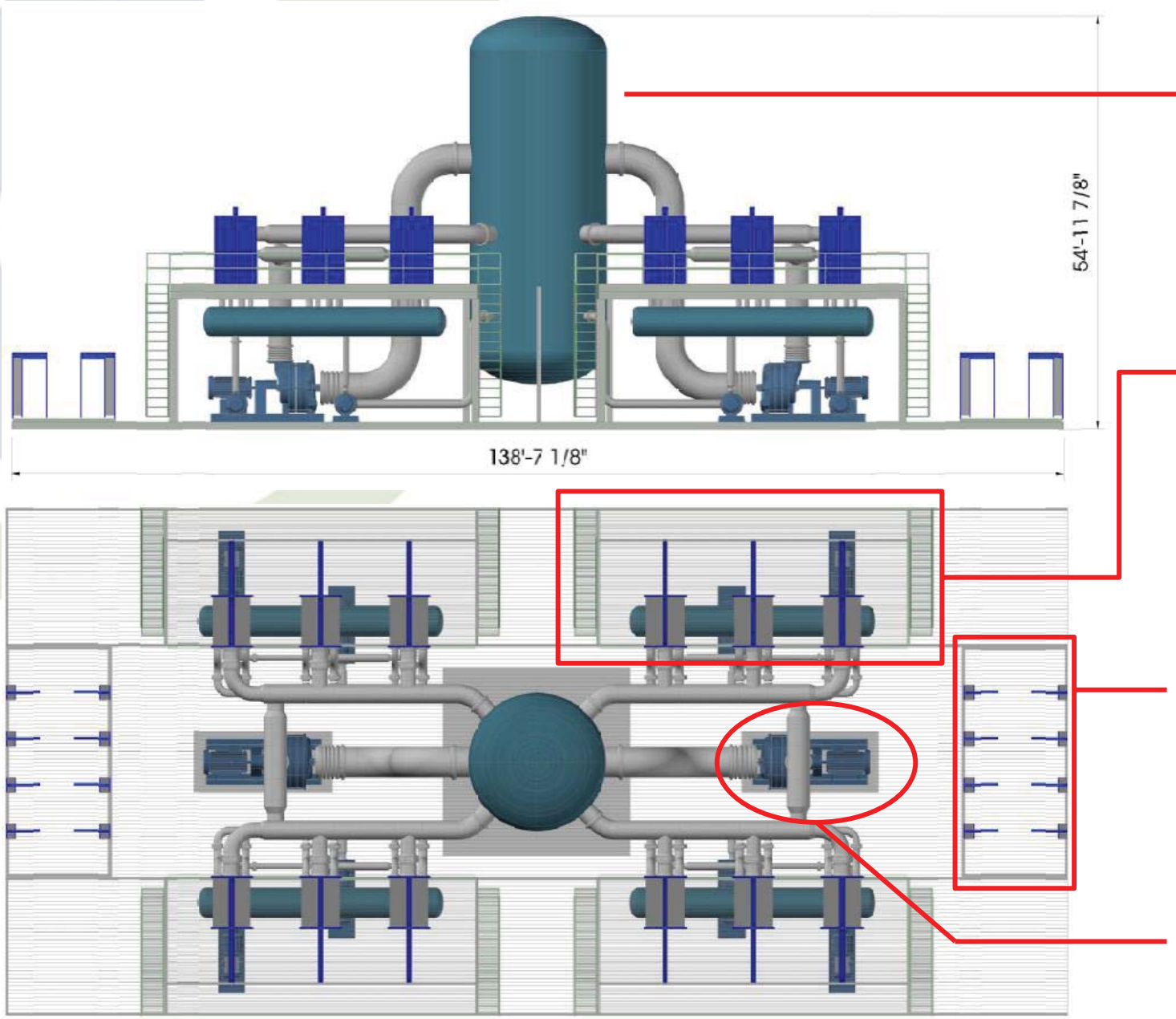
First system to meet Pennsylvania DEP discharge criteria (250mg/L Cl, 500mg/L TDS)

Modular Base Plant (MBP)

- The NOMADs are designed for mobility. They can be deployed until a larger base plant is needed and then be moved into new areas.
- The advantages of the Fountain Quail NOMAD technology apply to MBP plants as well.

✓ Easy Cleaning and Service	Entire system can operate at near capacity and a small portion can be in "clean-in-place" mode without shutting down.
✓ Low Height	Install in a building with overhead crane.
✓ Modular Design	System can be delivered in pre-fabricated skids.
✓ Efficient	High thermal efficiency in compact package.

30,000BPD Modular Base Plant



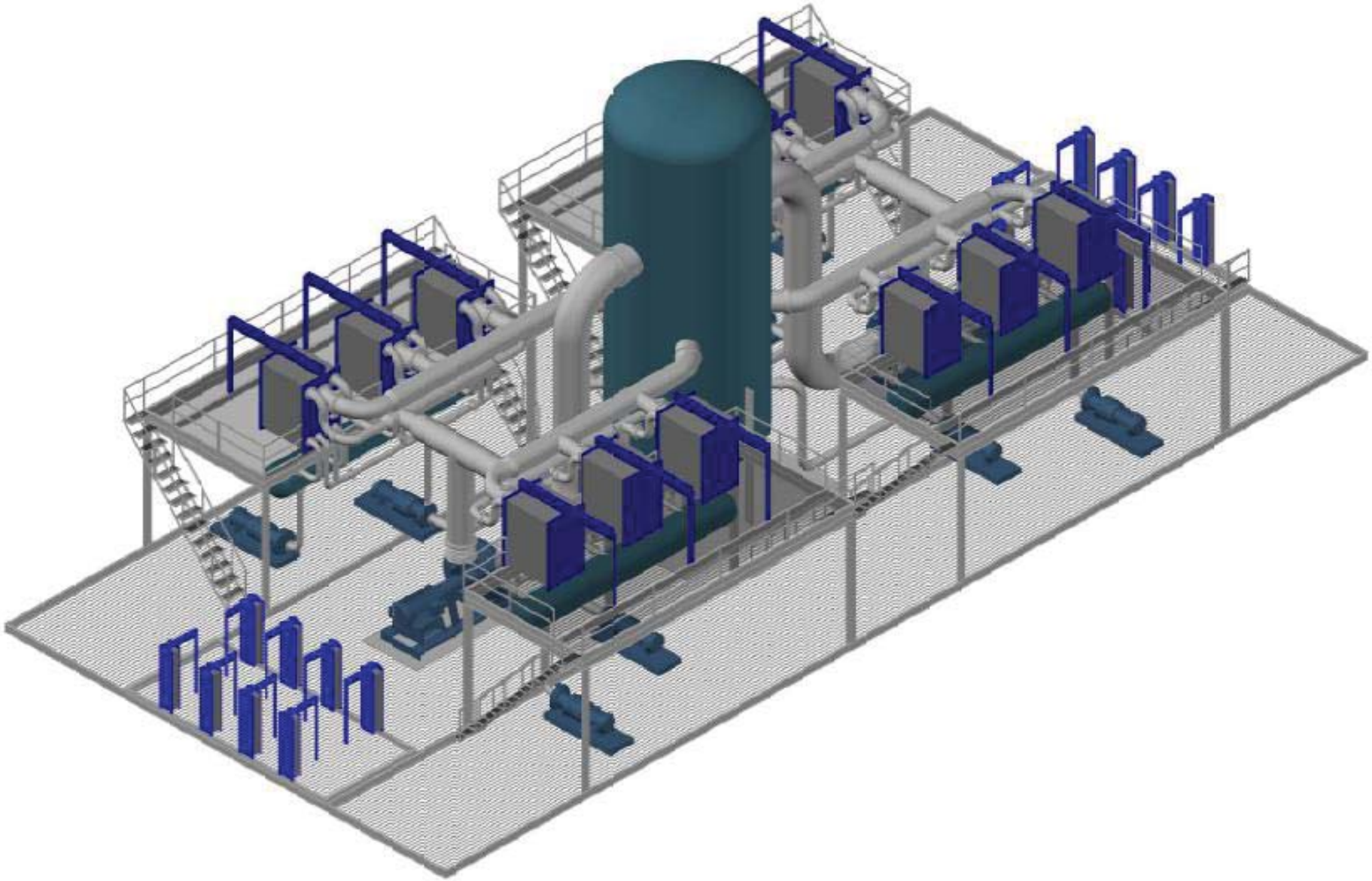
Single (1) Vertical Separator Vessel

Four (4) Pre-Fab Evaporator Modules

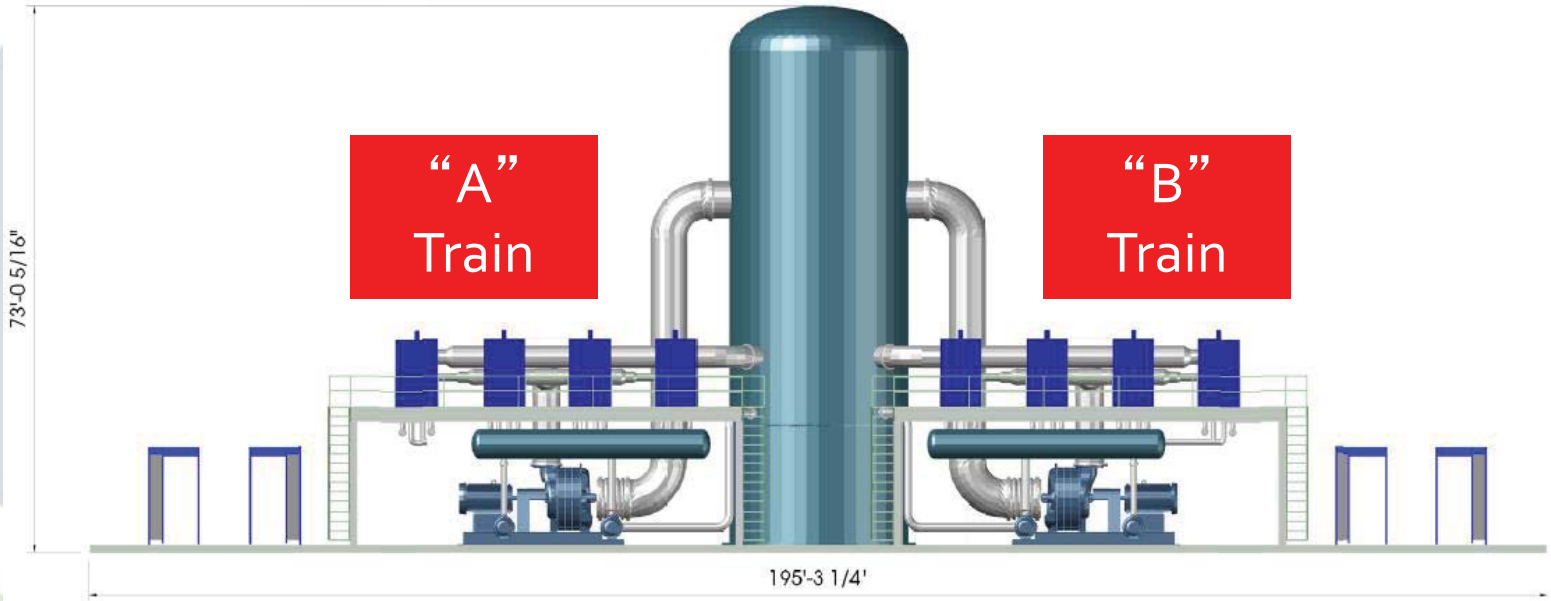
Two (2) Pre-Fab Preheater Modules

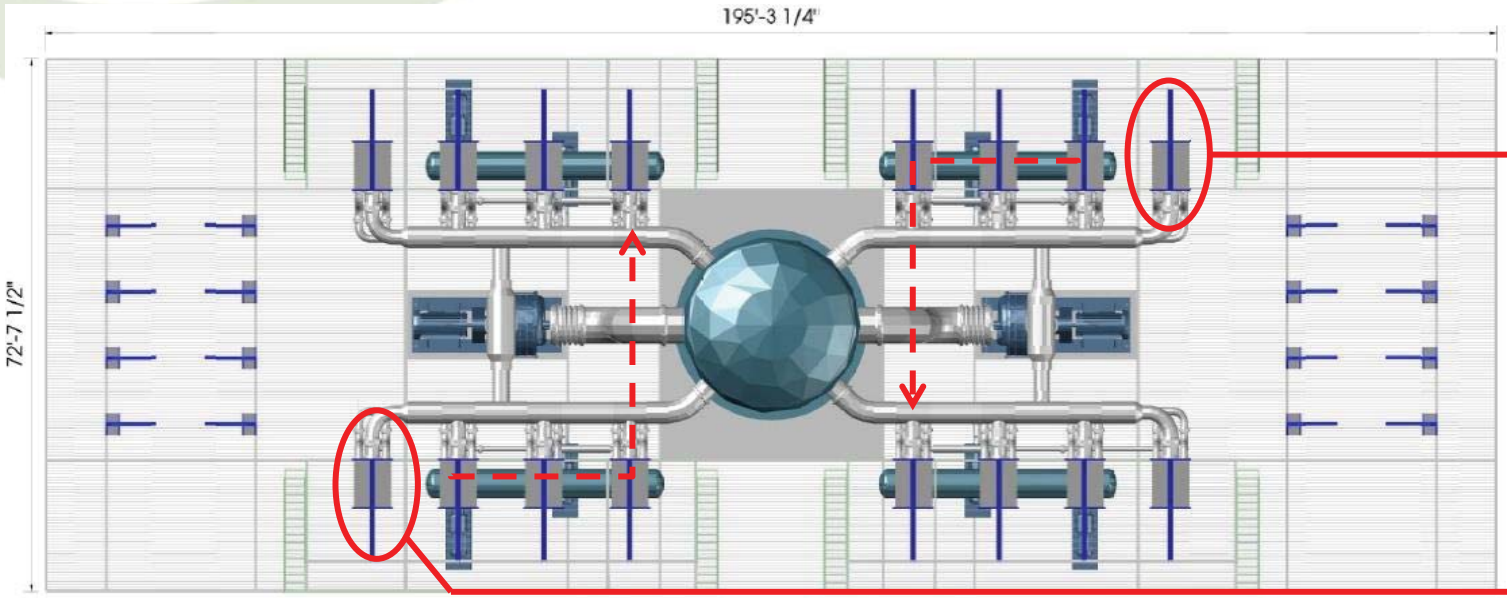
Two (2) Steam Compressors

30,000BPD Modular Base Plant



60,000BPD Modular Base Plant





Cycle any 2 exchangers through "C-I-P" and continue to operate at 100% capacity.

Compact Installations

EnCana SAGD Oilfield Evaporator – Foster Creek, Alberta (Canada)

Feed: Oilfield Produced Water (direct from skim tank)

Product: Distilled Water (60usgpm) for boiler feed water

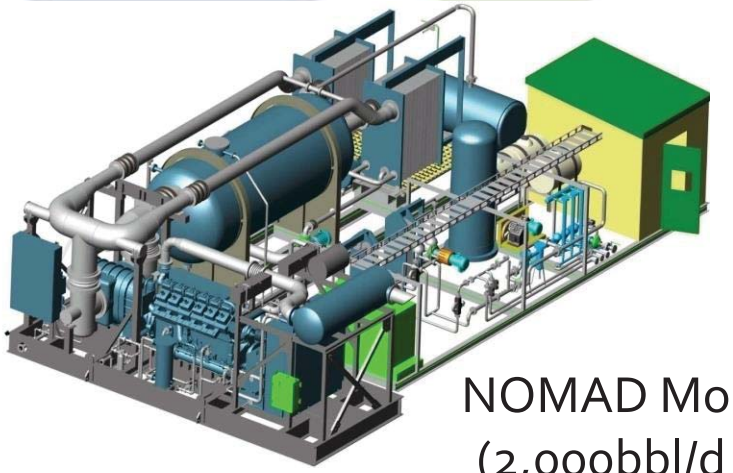
BP Brine Concentrator - Sarnia, Ontario (Canada)

Feed: 12-22wt% dilute salt brine (100 to 220usgpm)

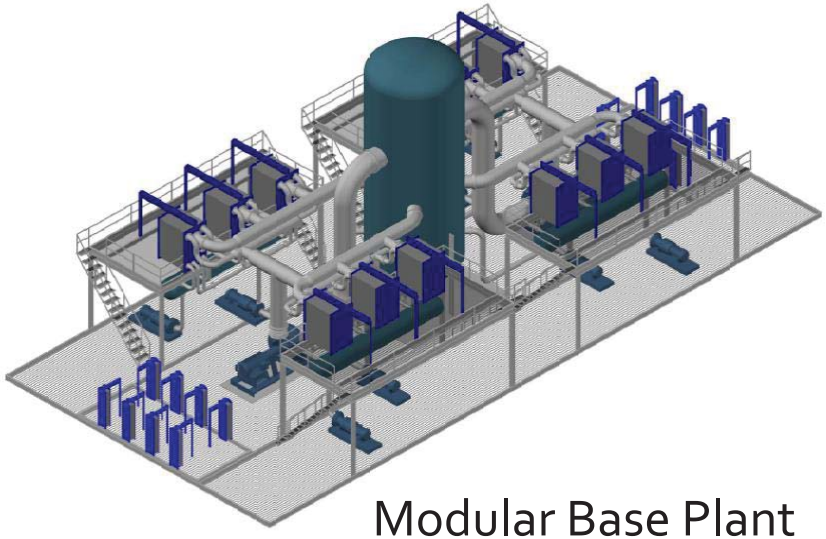
Product: 26wt% concentrated brine & distilled water (42usgpm)

Flexibility Required

- Sustainability is key.
- Example: Start with NOMAD; graduate to base plant as need increases.



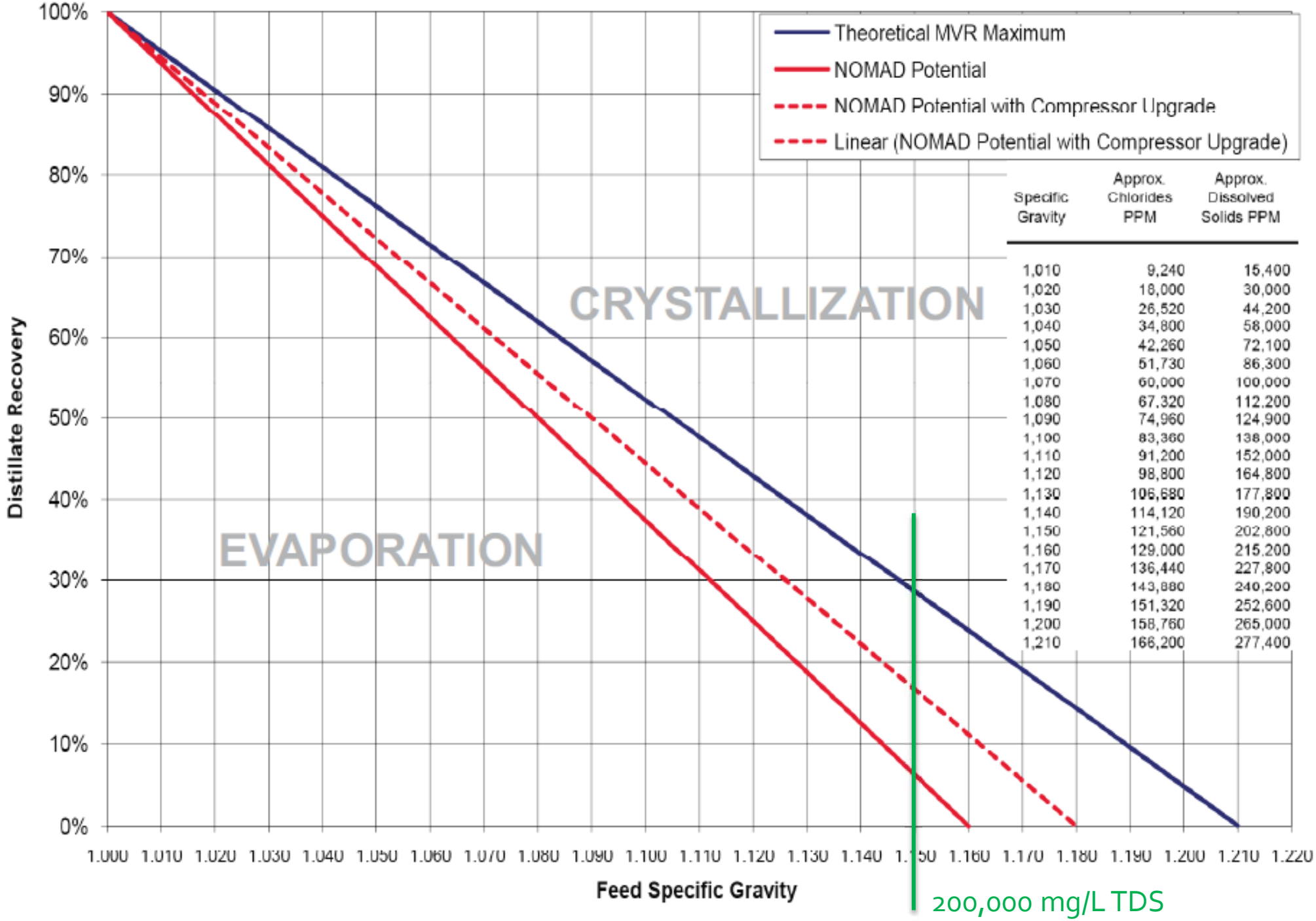
NOMAD Mobile Plant
(2,000bbl/d capacity)



Modular Base Plant
(60,000bbl/d capacity)

Energy Use

- To create a phase-change (liquid -> vapor) requires significant energy: 1,000BTU/lb
  - Systems that boil steam to atm are very energy wasteful – tend to rely on stranded gas as fuel. Concerns about air emissions (BTEX, etc.).
- To **maintain boiling** requires far less energy:
  - NOMAD theoretical: 25BTU/lb (1/40th)
  - NOMAD plant historical: 150BTU/lb
- Some evaporator companies state "energy per **feed** bbl" then forget to mention that they get only 10% recovery… (1,000BBL in, 100 treated).

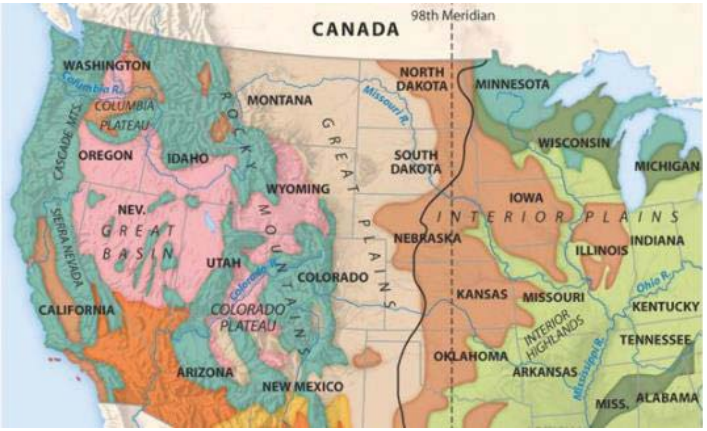


Specific Gravity	Approx. Chlorides PPM	Approx. Dissolved Solids PPM
1,010	9,240	15,400
1,020	18,000	30,000
1,030	26,520	44,200
1,040	34,800	58,000
1,050	42,260	72,100
1,060	51,730	86,300
1,070	60,000	100,000
1,080	67,320	112,200
1,090	74,960	124,900
1,100	83,360	138,000
1,110	91,200	152,000
1,120	98,800	164,800
1,130	106,680	177,800
1,140	114,120	190,200
1,150	121,560	202,800
1,160	129,000	215,200
1,170	136,440	227,800
1,180	143,880	240,200
1,190	151,320	252,600
1,200	158,760	265,000
1,210	166,200	277,400

FIGURE 1. MVR Evaporator Revovery Based on Feed Gravity for NaCl Brine

Oklahoma Issues

- Very high TDS (often >200,000mg/L).
  - Makes economic recovery a challenge.
  - Lends itself to a crystallizer.
- If evaluating a XLER then **managing salt** becomes a dominant challenge.
- Offers potential beneficial reuse of salt (chemical feedstock, etc.).
- Discharge permits (NPDES)
  - 98th meridian bisects OK.



ZLD – the alternative to SWDs

- ZLD – "use the whole buffalo".
- A **mighty technical challenge** dwarfed by a **massive economic challenge**.
- Salt becomes the elephant in the room.
- 10,000bwpd XLER – makes 160,000 ton/yr salt (Marcellus example at ~180,000mg/L feed).

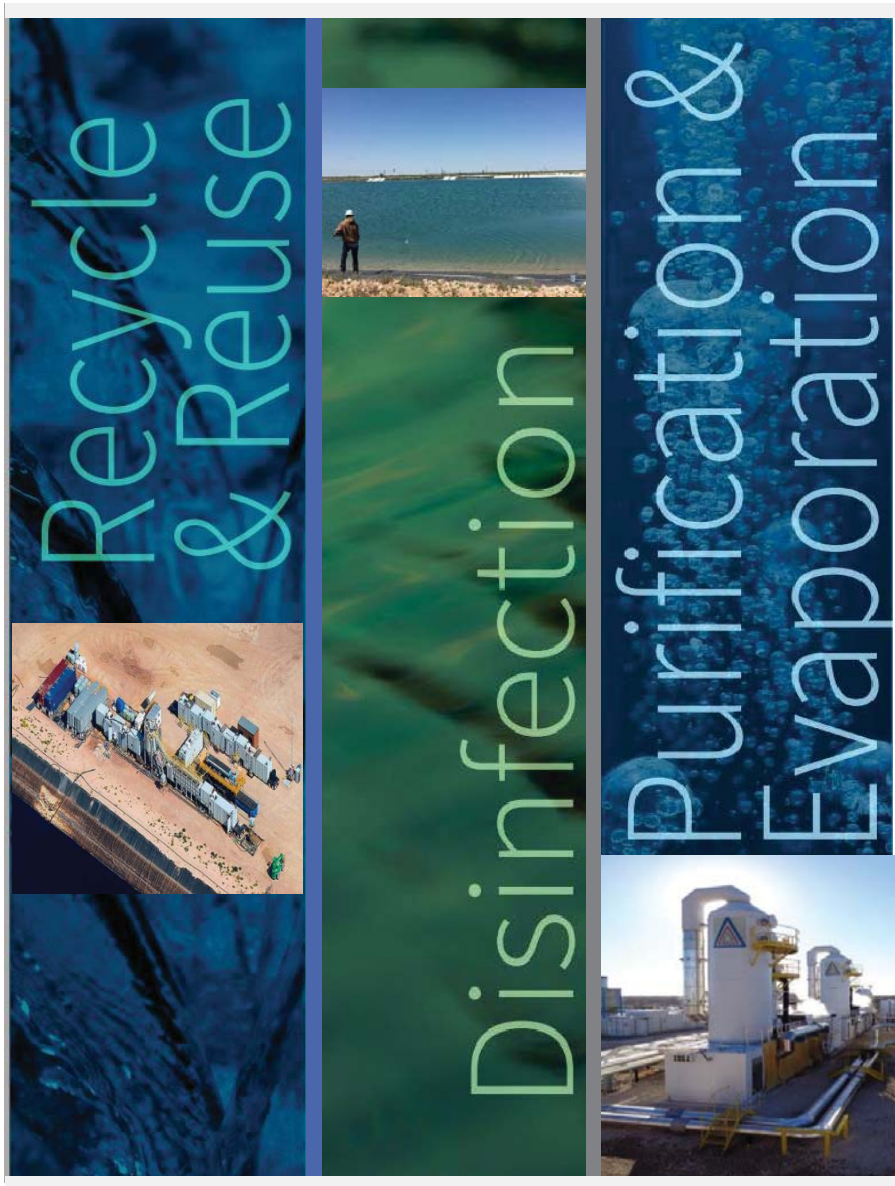
Produced Water Management

Reducing Cost Through Evaporative Disposal

Produced Water Case Study

Kushal Seth

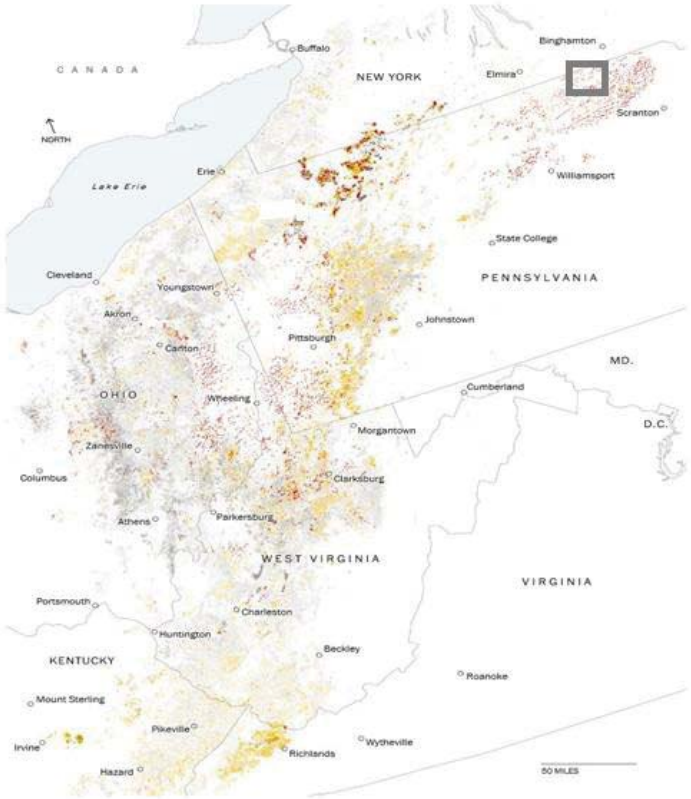
GRADIANT
ENERGY SERVICES



Case Study

Background

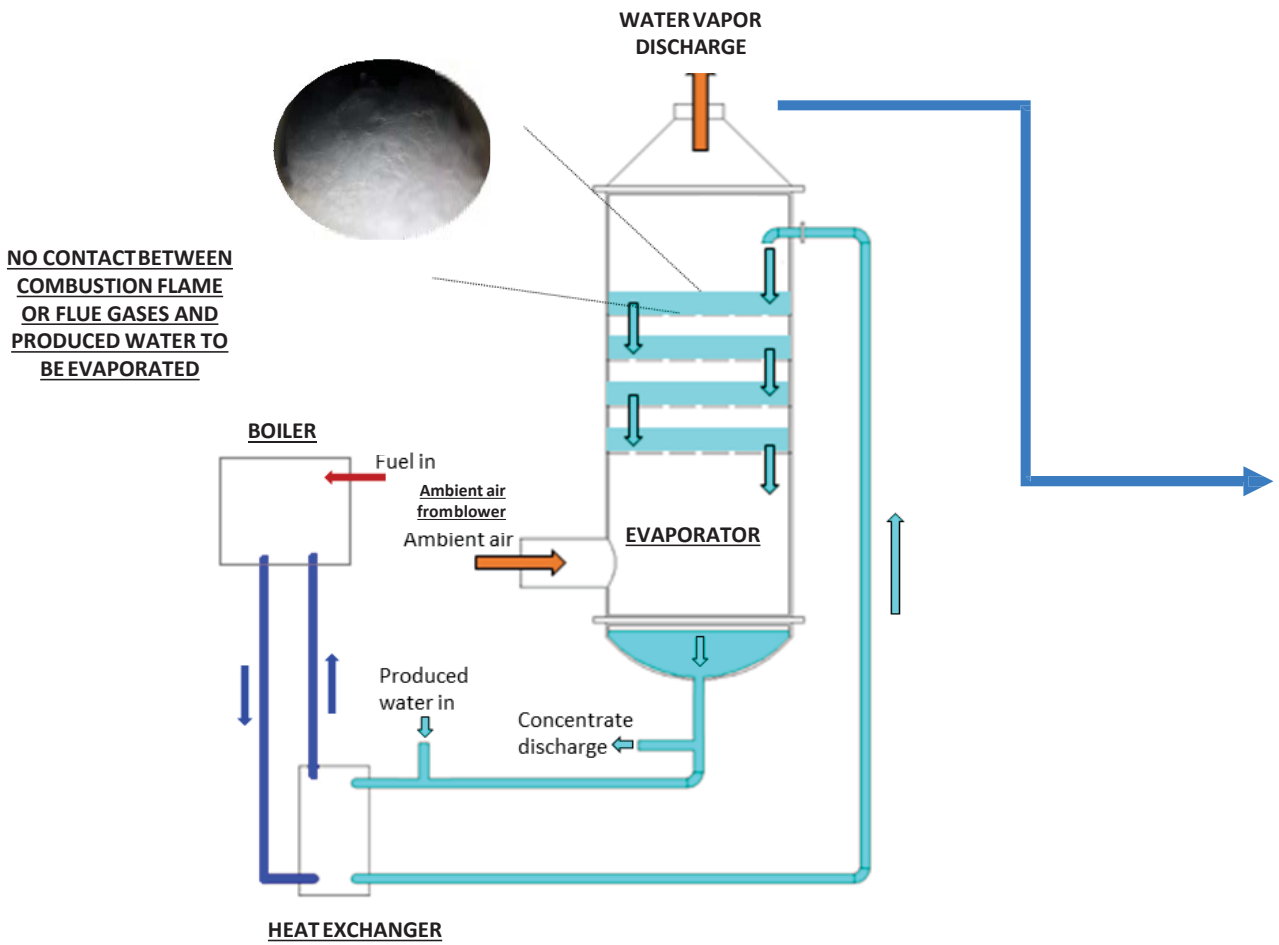
- Location : North East Marcellus
- Number of wells : >500 Wells
- Water Production : Most of the wells ~ 1 BPD
- Type : 45% of the wells - High TDS
- Flowback Phase : 0 – 2,500 BPD
- Frac Volume : 100 - 500K BPW
- Fracking : Fresh/Produced/Flowback
- Disposal Cost : $8 - 15/bbl

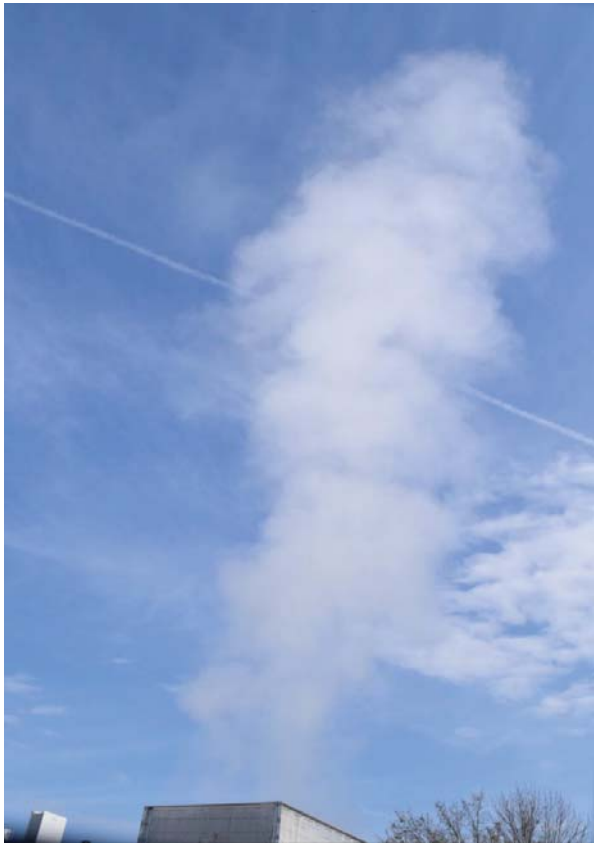


Objective : Reducing Water Disposal Costs

Technology - Carrier Gas Concentrator (CGC™)

Alternative to Expensive Trucking, Salt Water Disposal or Evaporation Ponds





CGC Design

Evaporation Capacity : 500 BPD

Footprint : 60’ X 70’
CIP Process and Boiler pump system
Influent, Recirculation and Effluent pump system
CGC Bubble column
Natural Gas Boiler and Air compressor

Interconnecting piping and power leads

Influent Water TDS
Variable

Operating Conditions

Top Brine Temp:	200 F
Air flow:	4,000 scfm
Thermal Consumption:	0.5 Mcf/bbl

Effluent Water
200,000-250,000 ppm

Technology - Carrier Gas Concentrator (CGC™)

Features for Cost Savings:

- **Compact :**
  - Multi-stage bubble column humidification
  - High heat and mass transfer rates
- **Automated :**
  - Proprietary control algorithm
- **Minimal Pretreatment :**
  - Robust internal design
- **Lower Energy Consumption :**
  - High energy effectiveness because of efficient multi-stage design
- **Lower emissions**
  - No direct contact
- **Reliability :**
  - Developed out of MIT
  - Lab tested for over 5 years
  - Commercially operated in the oilfield using various produced waters over 2 years

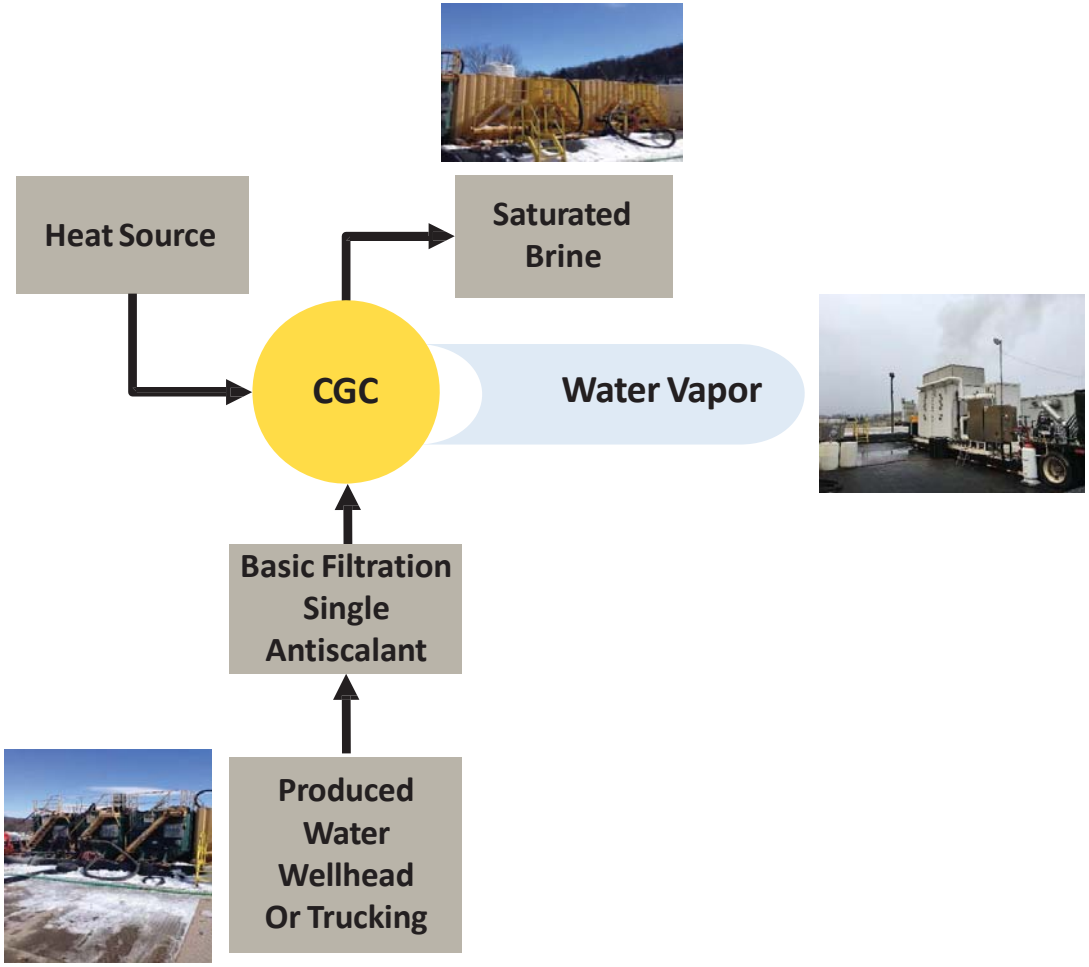
Application:

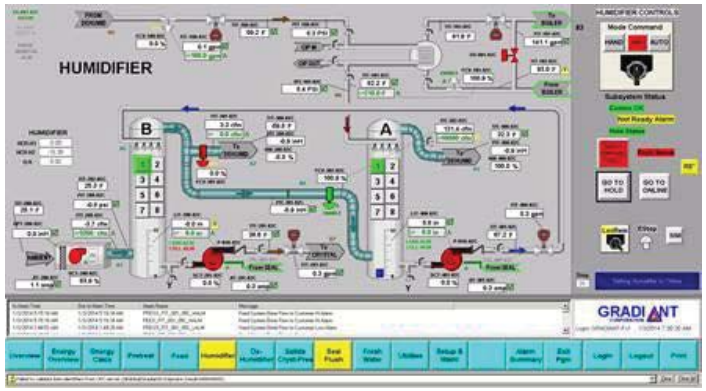
- Greenfield development
- Disposal constrained regions
- High trucking costs
- Enhancing evaporation pond or SWD capacity

Technology - Carrier Gas Concentrator (CGC™)

- **Permitting:**
  - PA DEP
  - Air Emissions (TPY)
- **Spills:**
  - Handled as per operator's SOP. No major potential due to
    - Lower volume
    - Nature of process – Automated
- **Influent and Effluent Testing on site:**
  - Stack Testing
- **Waste : Heavy Brine**
  - Can be made a ZLD process
- **Potential Impacts – Methanol**

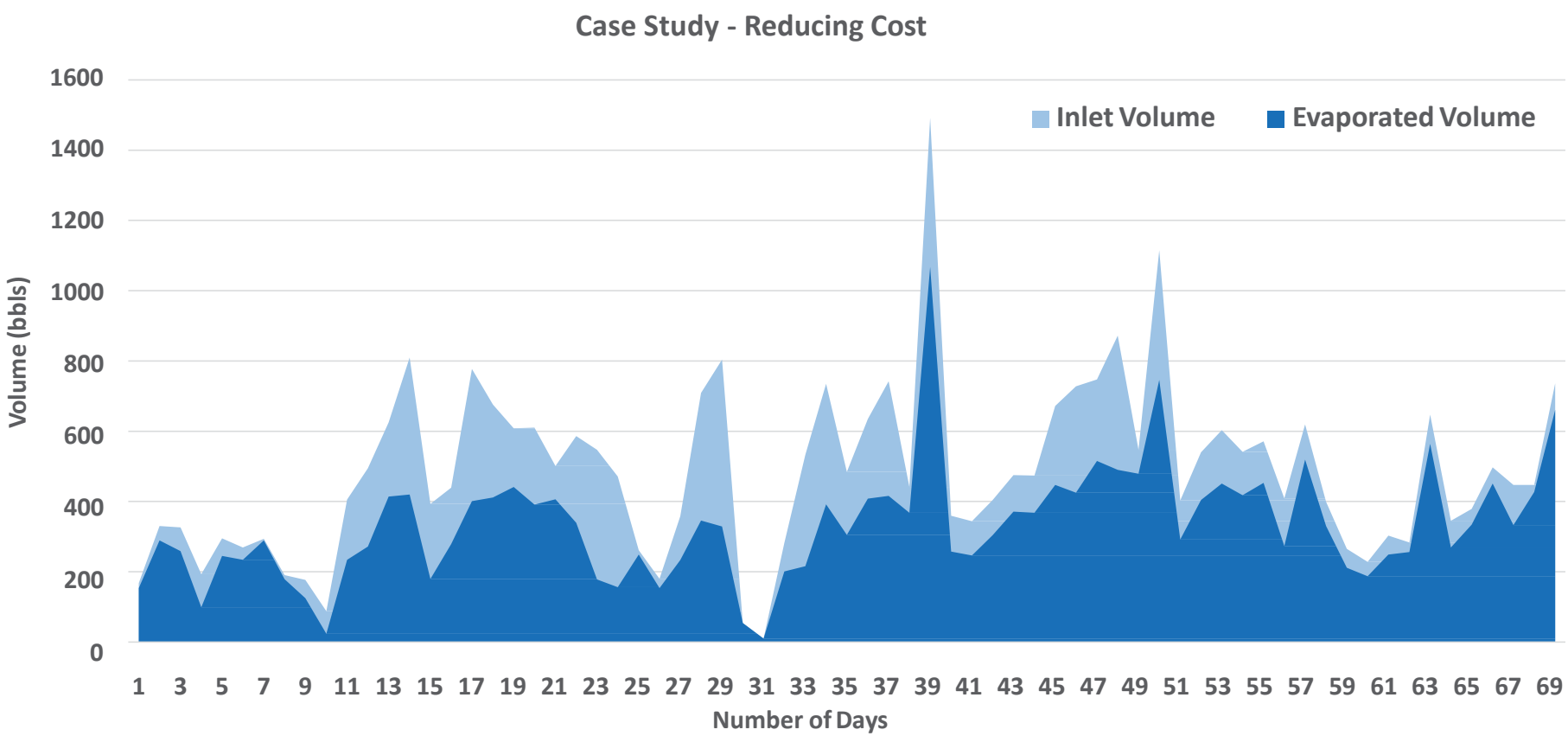
Case Study : Set-up



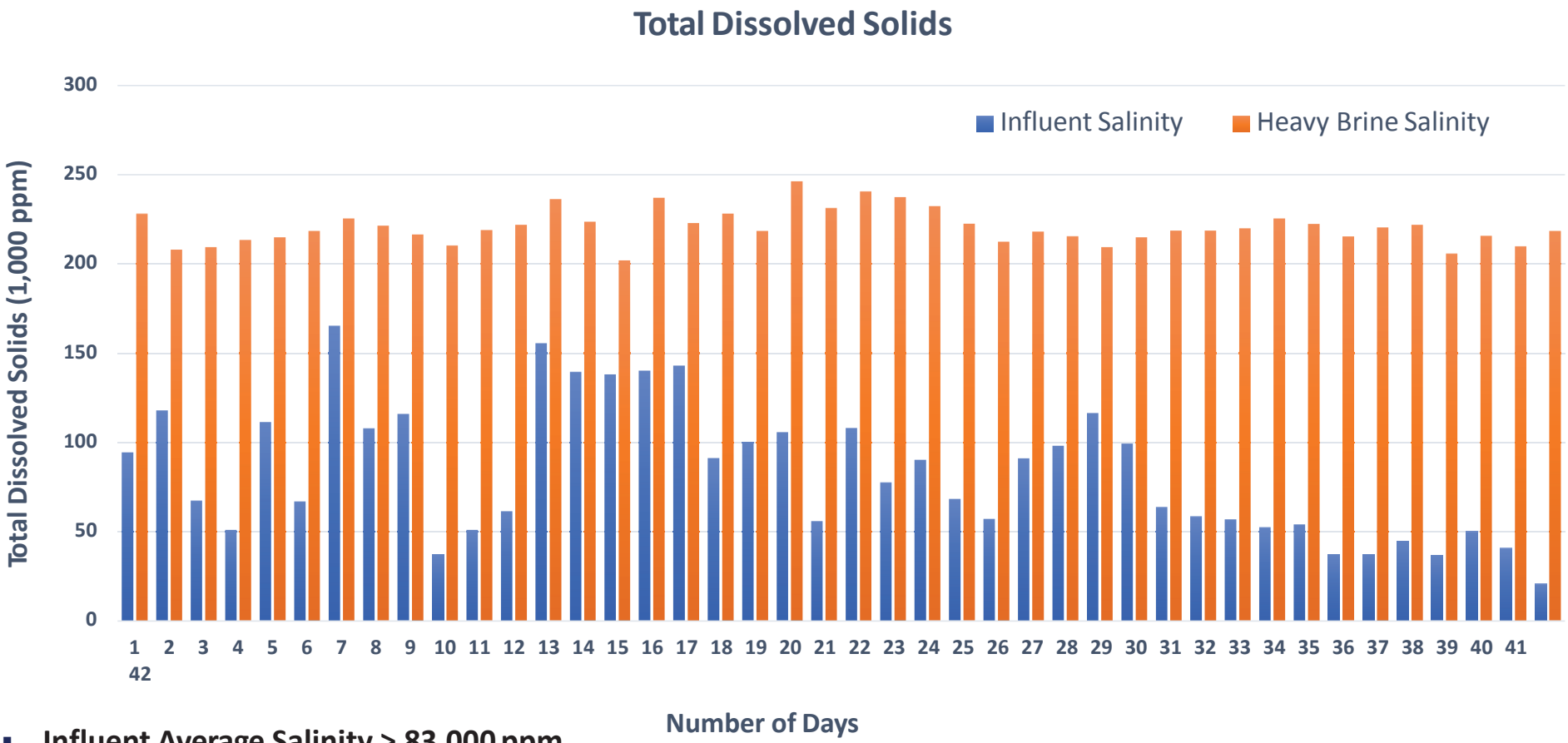


SCADA Connectivity

Case Study : Reducing Trucking Cost Through Evaporation



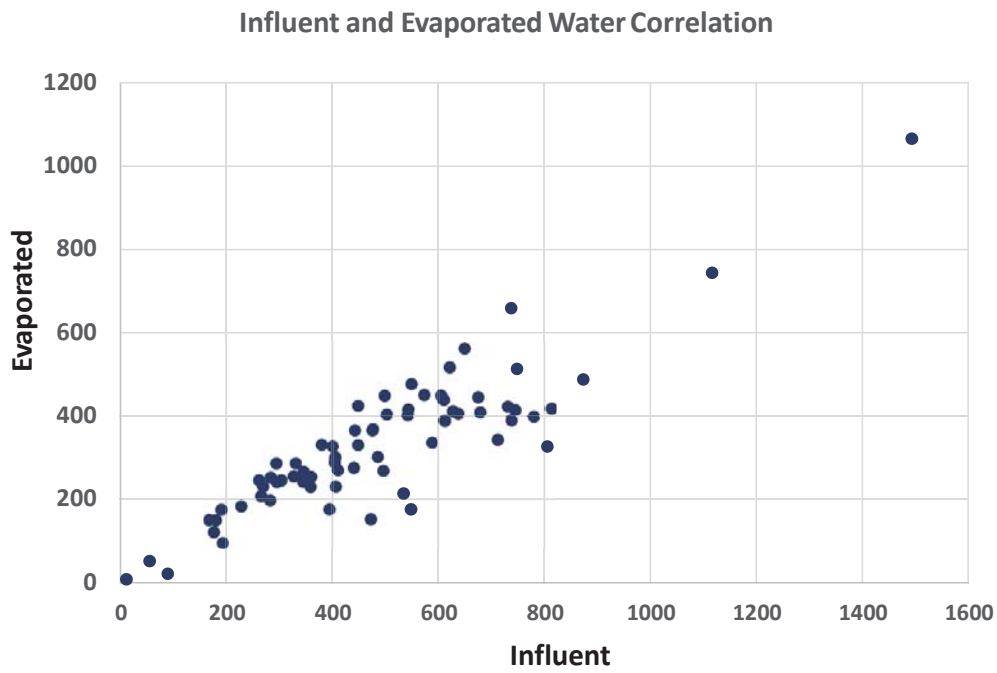
Case Study



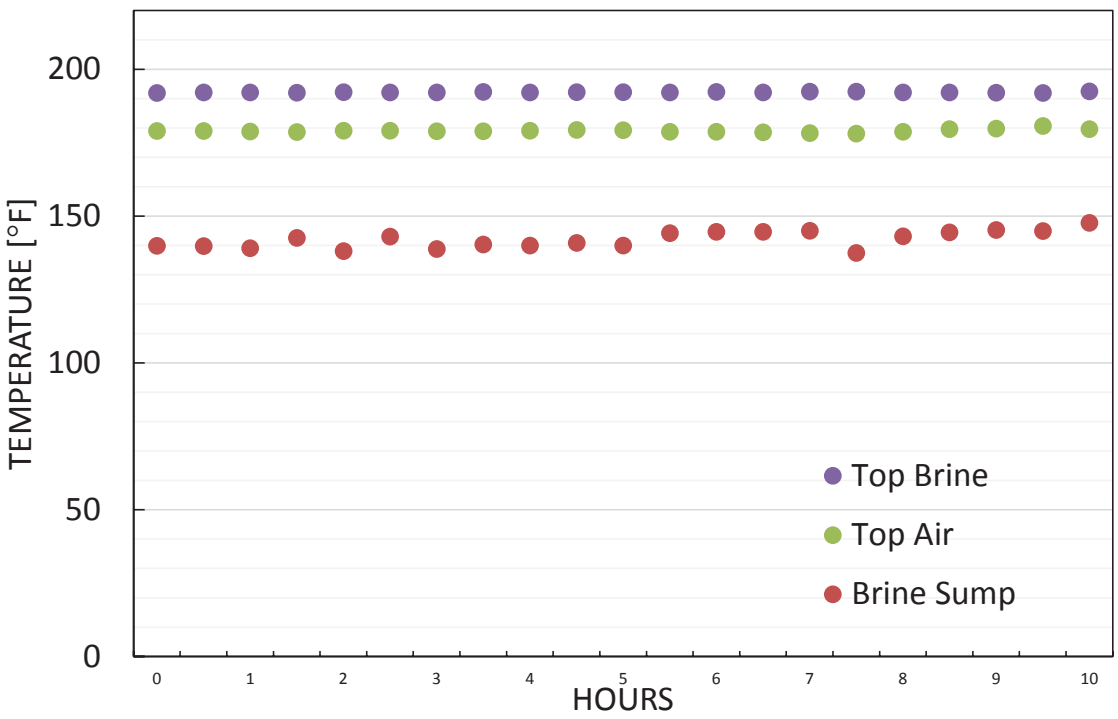
- **Influent Average Salinity > 83,000 ppm**
- **Generated Heavy Brine Salinity > 221,000 ppm**

Case Study : Reducing Trucking Cost Through Evaporation

- **45% Cost savings compared to trucking**
- Consistent Operation – Water Evaporated
  - Influent
  - Evaporated water
- Clean vapor
- Robust System : Varying Influent TDS
- Minimal Pre - Treatment
- Ambient Pressure
- Low Operational Temperature
- Operated November ’16 – February ’17
  - Winterization

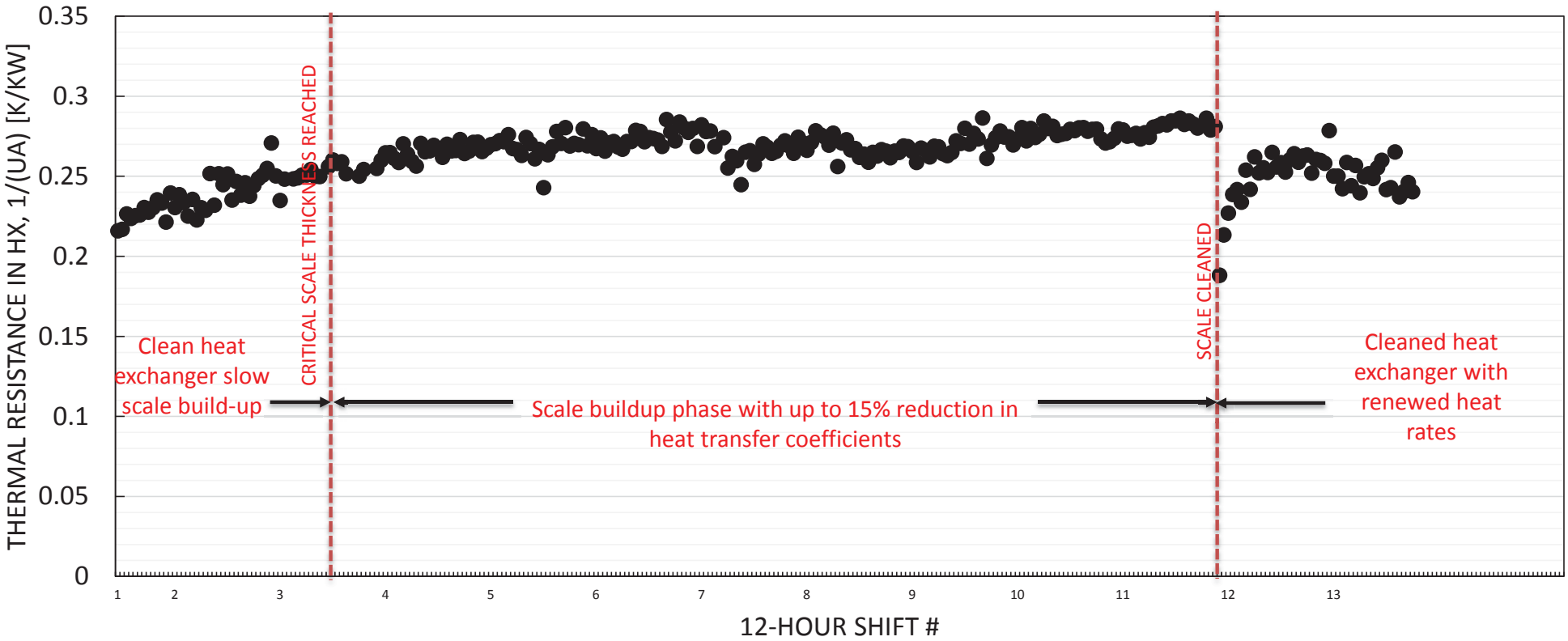


Temperature Profile of System



- Temperature profile throughout column is monitored ensure consistent performance
- For smooth operation, consistent temperatures are a crucial parameter
- Ensures consistent production and energy usage
- Data points show a 30 minute average during steady state operation

Scale accumulation on HX plate



Lessons Learnt/Challenges

- Emissions
  - Source or Centralized
  - VOC's – Air Stripper
    - Modelling
  - Methanol
- Water Chemistry
  - Defoamers, Gas Hydrate Inhibitors
- Stack Testing
  - Cost
- Natural Gas
  - Availability
- Regulations
  - PM 10, PM 2.5
  - TPY

Acknowledgements

Chesapeake Energy Corporation

Q&A

logic energy solutions

Presented By: Trey Moore

January 17, 2018

HISTORY

- Ownership has a background in O&G production and processing equipment (Cimarron Energy 1977-2012)
- Urged by customers in early 2000's to provide evaporative solution for produced water in the Piceance Basin
- Began utilizing submerged combustion technology in 2009
- Founded Logic Energy Solutions in 2012 with a focus on oil and gas wastewater evaporation
- Operated evaporators in the following producing areas:
  - STACK (Oklahoma)
  - Permian (Texas)
  - Fayetteville (Arkansas)
  - Bakken (N. Dakota)
  - Marcellus (Pennsylvania)
  - Utica (Ohio)
  - Powder River (Wyoming)

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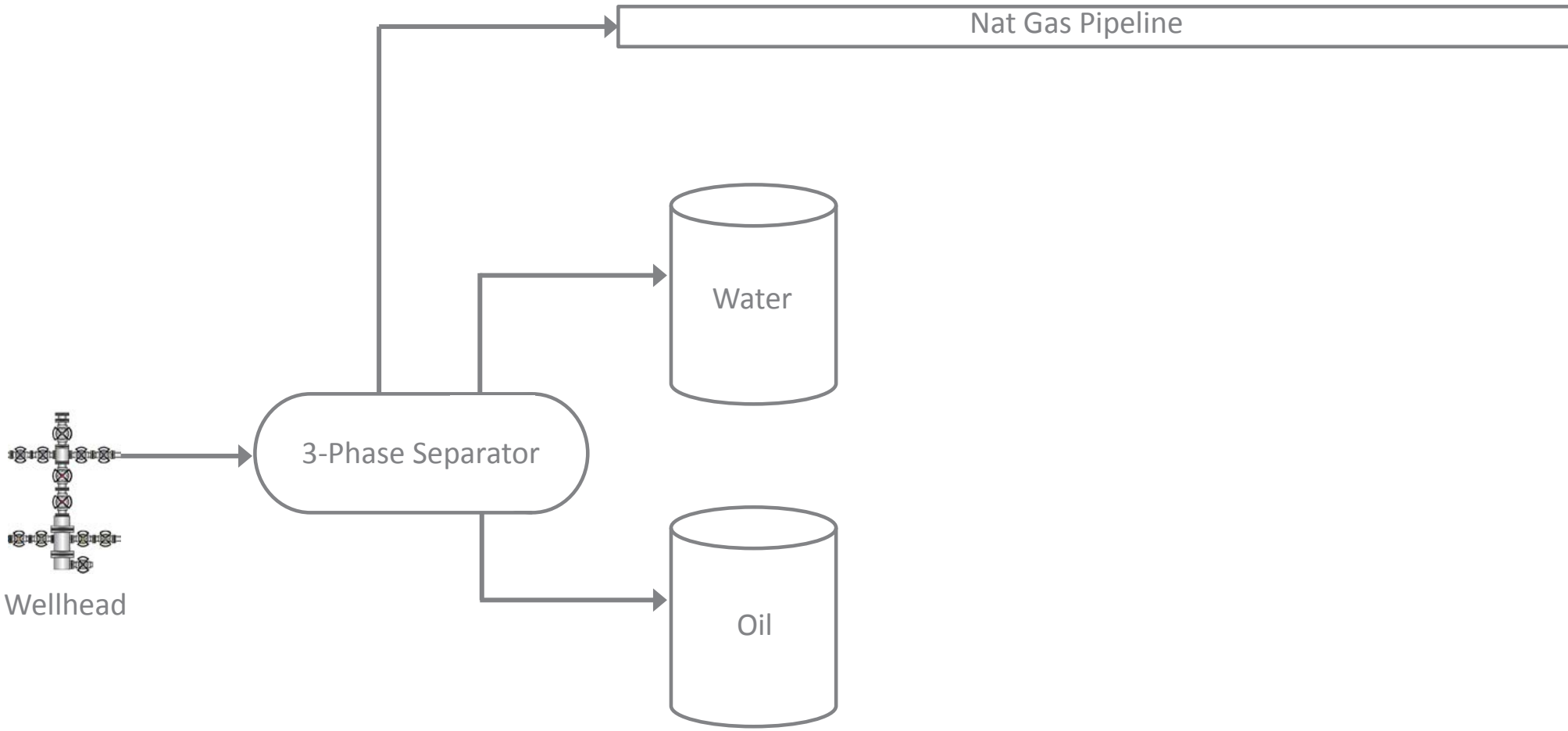
STRATEGY

- Evaporate close to the source, and reduce truck traffic as a result
- Provide modular equipment that can be easily relocated

STRATEGY

Well Site Flow Diagram



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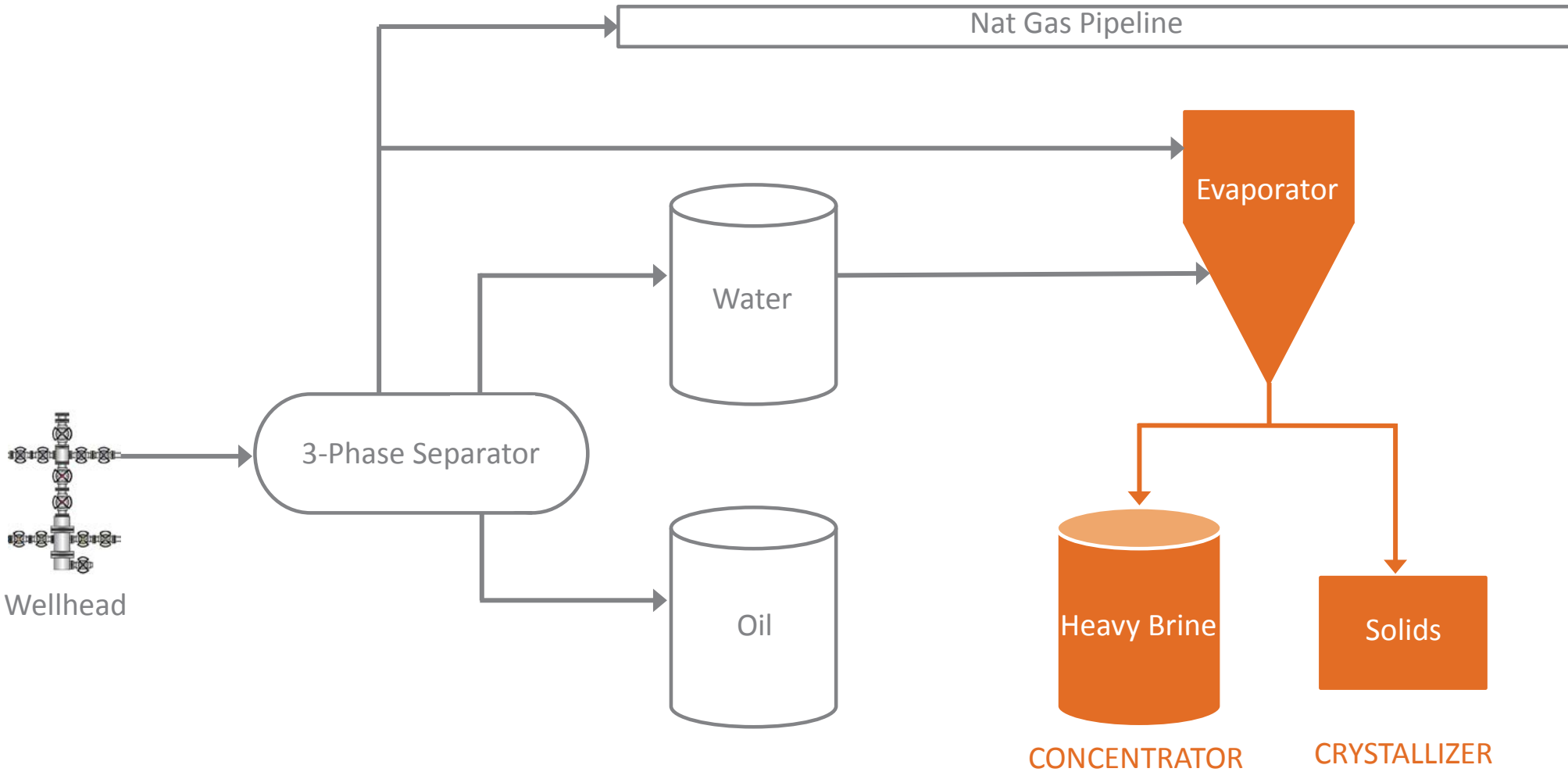
STRATEGY

Well Site Flow Diagram



logic

STRATEGY

Volume Reduction via Concentration

Influent TDS (mg/L)	325,000mg/L Concentrate
30,000	91%
50,000	85%
100,000	69%
150,000	54%
200,000	38%
250,000	23%

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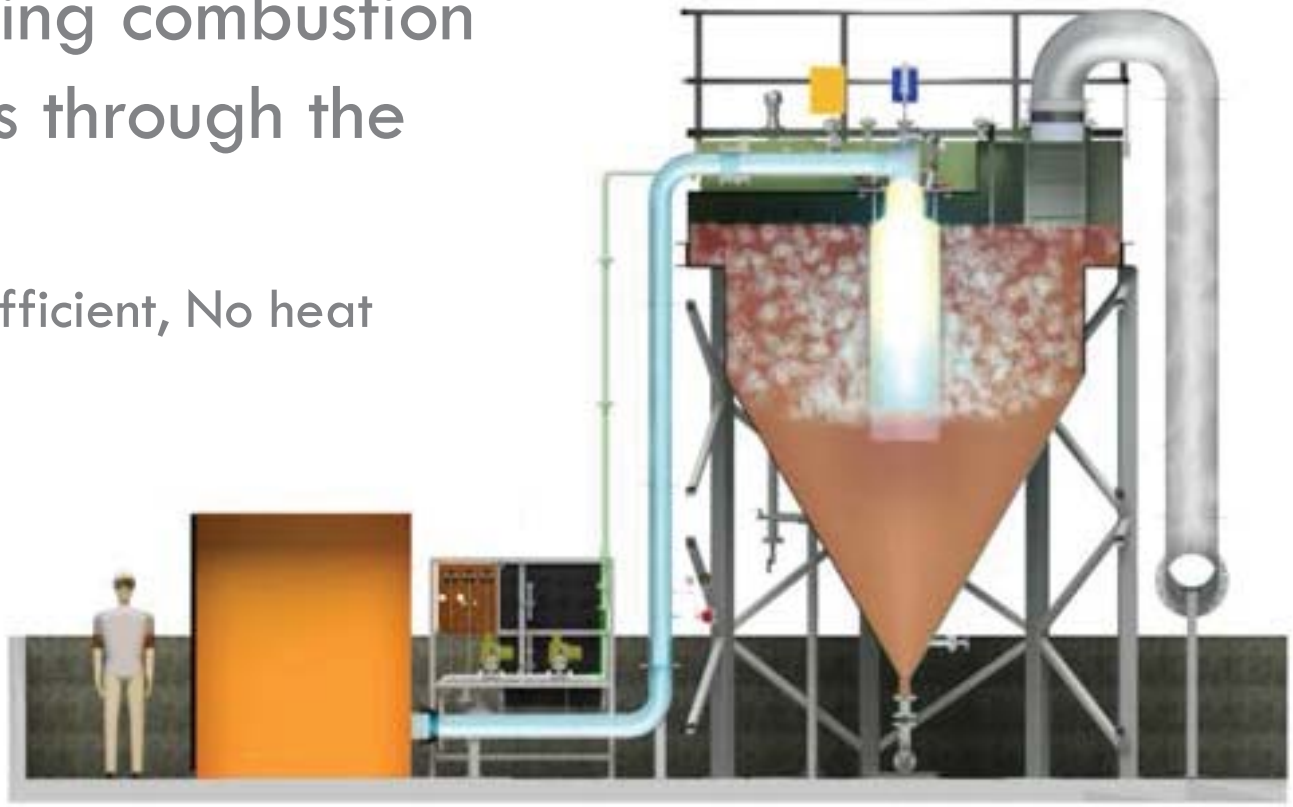
PROCESS

Submerged Combustion is a thermal process which heats a liquid by forcing combustion exhaust gases through the solution

Primary Benefits: Efficient, No heat transfer surfaces



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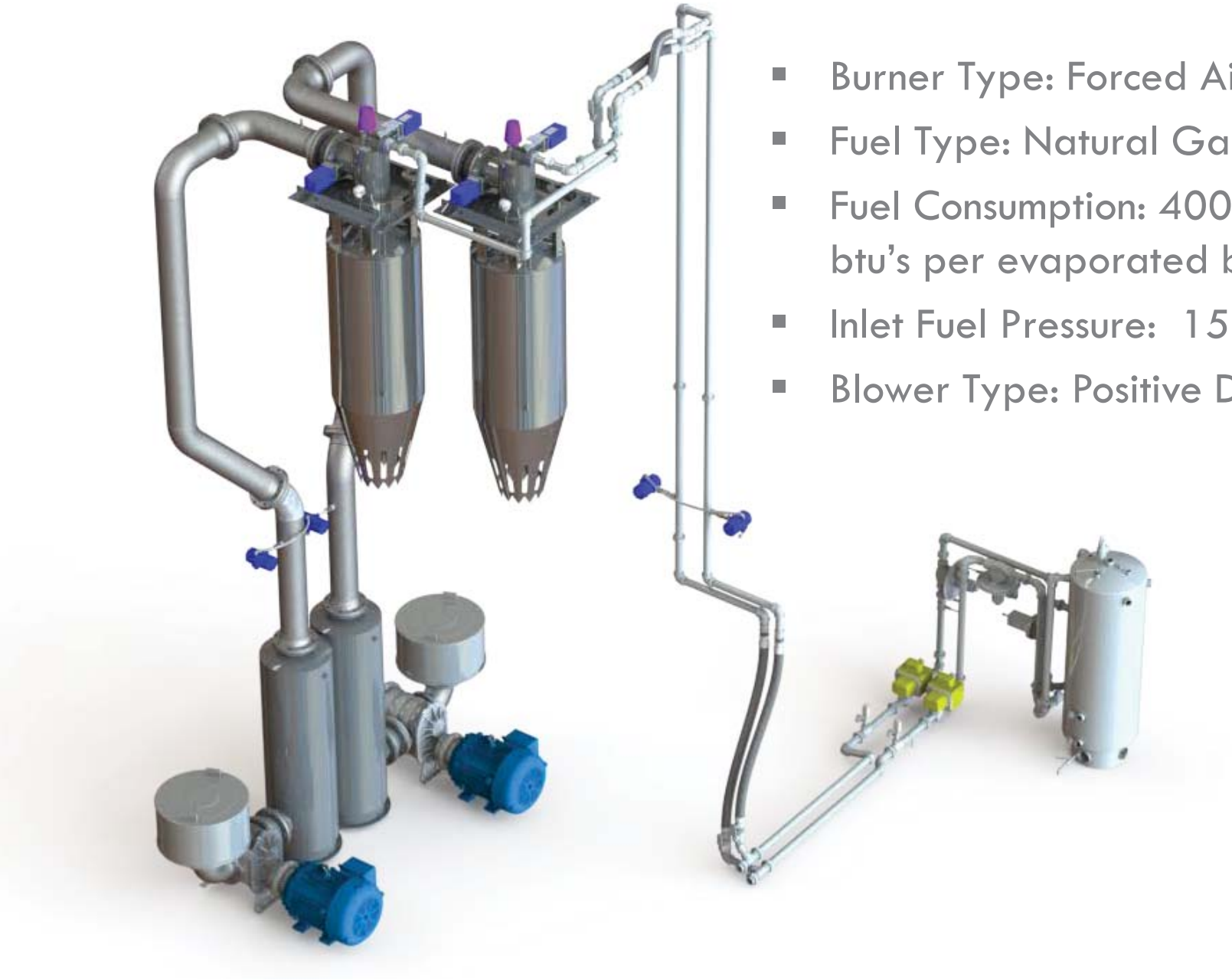
PROCESS



- Burner Type: Forced Air
- Fuel Type: Natural Gas
- Fuel Consumption: 400,000-450,000 btu's per evaporated barrel
- Inlet Fuel Pressure: 15 psi
- Blower Type: Positive Displacement

logic

PROCESS

- Evaporate up to 1,000 bpd (1,750 gal/hr)
- 1 Day Mobilization
- 25'W x 25'L x 30'T
- Dry Weight of 45,000 lbs
- Operating Pressure: 10 Oz.
- Operating Temp: 180°F
- Materials of Construction:
  - Carbon Steel
  - 2205 Stainless Steel
  - Fiberglass

logic

IMPACTS

- NOISE: <85 dBA
- VISUAL: White plume that varies in size depending on atmospheric conditions and evaporation rates; never had a complaint
- SURFACE: TDS of water vapor is less than 500 mg/L
- ODOR: Little to no smell, unless VOC's are in the vapor plume

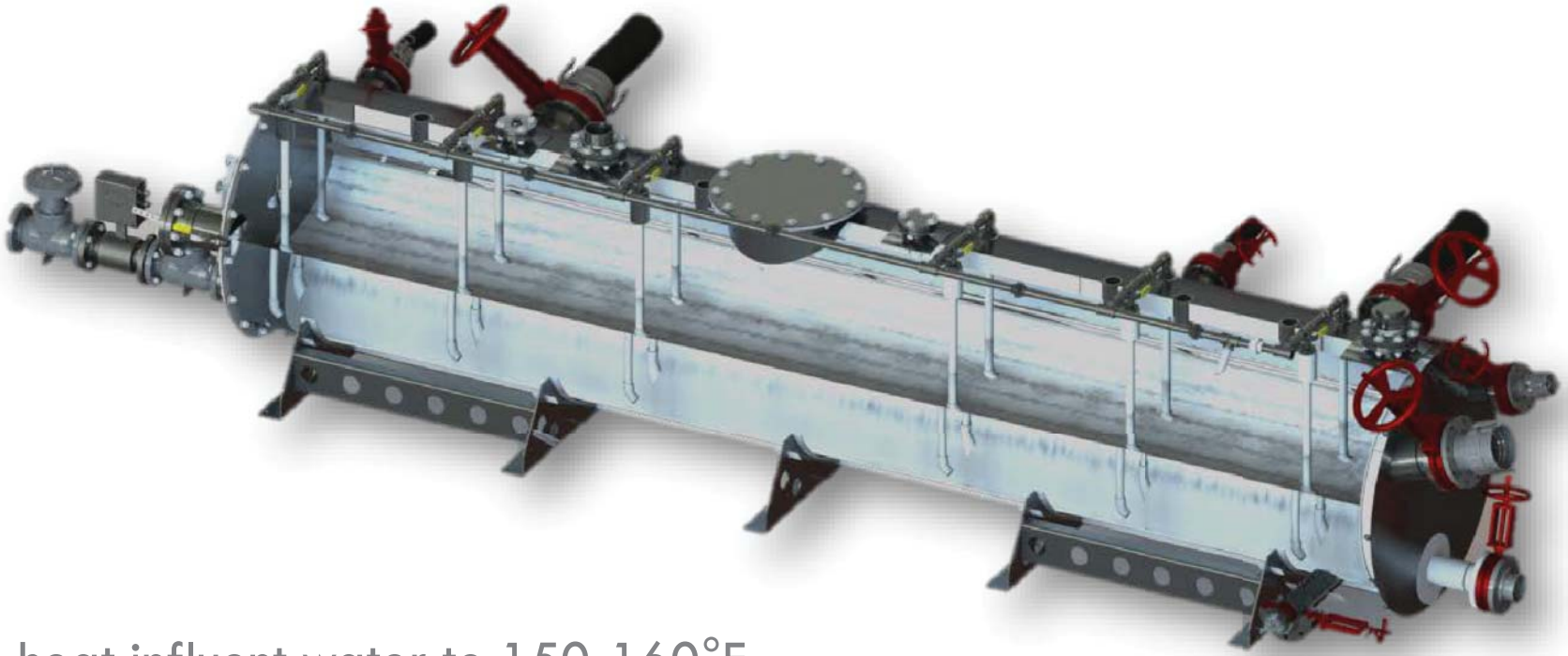
logic

MANAGING EMISSIONS

- Particulate Matter (PM): Carryover of droplets containing solids
- Combustion Gases: Incomplete combustion causes the release of organic compounds to atmosphere
- Organic Compounds (Entrained in the Water): Organic compounds with a boiling point equal to, or less than the evaporator operating temperature (methanol is a challenge)

logic

MANAGING EMISSIONS



- Pre-heat influent water to 150-160°F
- Sparge water with blower air
- Recover volatilized organic compounds and inject into burner

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WHERE IS THE CATALYST?

- Disposal wells are inexpensive and easy; the default for producers
- Forced evaporation is relatively new and unfamiliar to the O&G industry; still kicking the tires
- Penetrating a market requires:
  - Cheaper than injection (T&D) on a direct cost basis; forget the hidden / soft costs
  - Easy for the producer to implement

logic

GETTING CREATIVE

- Price reduction for evaporation
  - Design
  - Scale
  - Volume through quantity
  - Product mix
- Investing in product mix
  - Bundle production and flowback services with evaporation yields cheap and easy

logic

CONTACT INFORMATION

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tmoore@logic-es.com

Website: www.logic-es.com

Neptune

FS Global

Fisk Neptune processor

Water Remediation Technology Overview

January 2018

Company Status & Key Initiatives

- Fisk Engineering Services (FES) was formed to hold certain assets and operating business units within single member LLC's.
- After launching the business during the 2nd quarter of 2015, FES provided self funding for technology development and operations.
  - Inventor & developer, Brian Fisk, has been developing this technology for nearly 20 years.
- Fisk Environmental Technology LLC retains the intellectual property assets of the company.
- The following overview provides a perspective on or current efforts and results since our initial business launch.

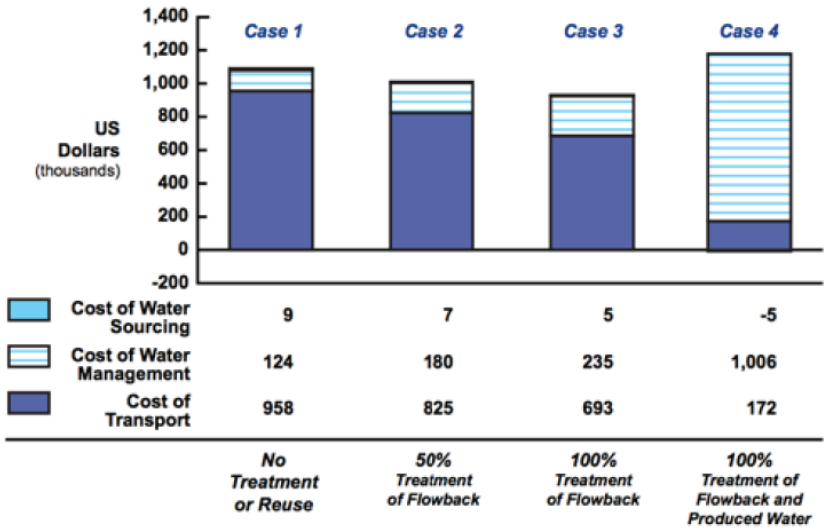
How Neptune Addresses the Market

- Neptune FS Global has created an environmentally friendly and efficient water remediation system, the Fisk Neptune Processor.
- We are a Nashville, TN based company with focus on the oil and gas business, mining and geothermal sectors.
- Neptune FS Global develops and commercializes key technologies for water reclamation projects in the oil & gas industry, mining services and industrial pollution.

Economic Impact of Disposal & Treatment

- Oil and gas producers are all coming under significant political and regulatory scrutiny for traditional water waste and disposal practices.
  - Deep concerns are surfacing over environmental damage as well as public health.
  - When treatment and logistics costs are included, the actual cost for produced water ranges from $2.50~$11.75 per barrel.
  - This represents an approximate $30 billion per year industry alone in the United States

Lifetime Cost of Water Management: Hypothetical Marcellus Shale Gas Well



Source: IHS

Introducing the FNP

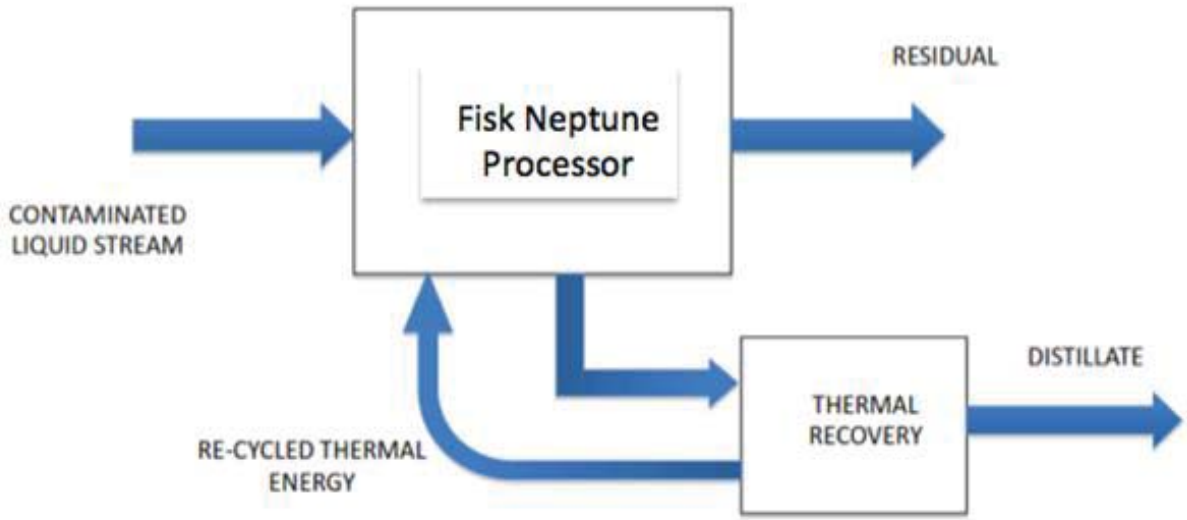
Fisk Neptune
processor

Fisk Neptune Processor

- The Fisk Neptune Process is a standalone solution for industrial water recovery.
  - High Chlorides mixed with grease, oil, metals and other acids etc. can all be economically restored.
- The equipment is designed on a modular platform reducing downtime and minimizing in field problems.
  - Each module can be restored at our central repair location if necessary.
  - Each machine is monitored at a central location. Auto diagnosis is available to identify the source of the delay.
- Neptune FS Global systems are designed as towage trailers in 53 foot container modules to allow uniformity with today's transportation requirements.

How It Works

- The FNP is a thermally enhanced series of stimulation, which is then processed to recover energy and enhance further processing goals increasing viability.
  - The full gamut of enhanced separation techniques is employed while combining a resource recovery process to develop viable by-products.
  - This style of processing is rare in our industry today and the thermal processor that can accomplish this is new; processes are designed for continuous flow.



FNP Unit Design – Gen I

Getting To The Last 25%

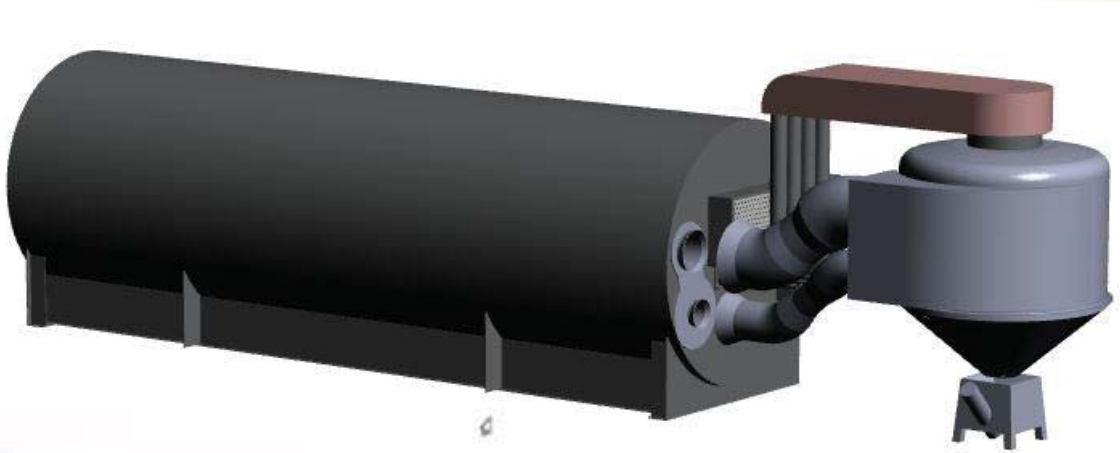
- Minimal on-site operations personnel required
- Low cost, simple maintenance and training
- Treats solid and liquid wastes simultaneously
- Safe and simple, minimizing exposure to hazardous materials
- Makes being green bankable
- Rapid return on investment
- Treat contaminants that other solutions cannot
- Reduce treatment costs with proven, highly efficiency thermal transfer methods
- Convert waste to energy to revenue
- Meet tougher environmental regulations, avoiding fines

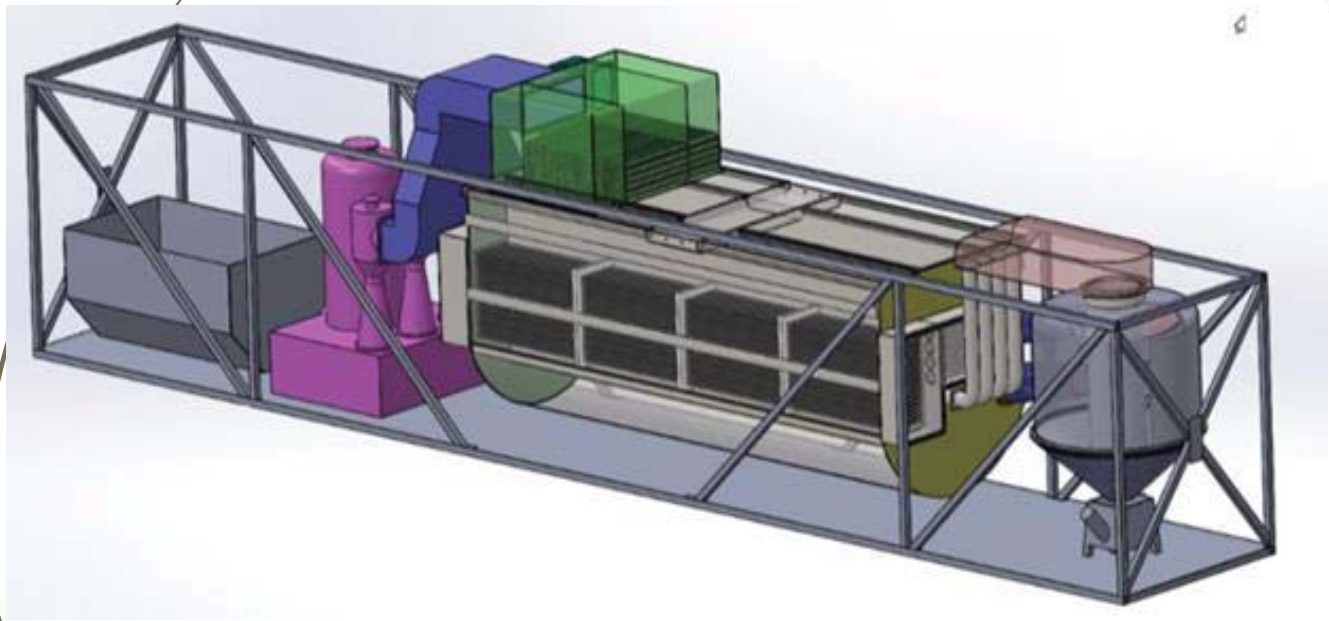
What design elements are unique to the FNP?

- The Fisk Neptune Processor is a combination of several known process technologies applied in the overall design.
- Critical to the unit efficiencies is the burner design, the Fisk Burner, for application and use in the thermal processing of the unit.
- The Fisk Burner also allows for using flare gas from the well-head, diesel, natural gas and/or recovered hydrocarbons from the water being processed.
- The FNP unit is built within a 53-foot tube frame/skid plate and has a circumference of 96 inches.
  - The design is fully scalable; however, the current Generation IV standard configuration will process approximately 3,000 barrels per day (BPD) of water to potable or 8,000~10,000 BBD of water to pure brine, depending on turbidity of the original input.

FNP Unit Design – Gen IV

Gen IV standard configuration will process approximately 3,000 barrels per day (BPD) of water to potable or 8,000~10,000 BPD of water to pure brine





Low Cost Maintenance

- The Fisk Neptune processor is a platform based modular system. Modules are easily replaced in the field, or a complete unit can be changed in minutes minimizing down time or customer well site problems.
- The Fisk Neptune Processor is economical to operate with the Fisk Engineering Services bench system, (used to conduct testing) having shown to be effective all types of waste water presented.
- The Fisk Neptune Processor media filters provide flexibility in targeting certain types of contaminant, (metals, organic and nonorganic substances).

Normal maintenance allows for in-field repair/replacement while resulting in a useful life exceeding fifteen years.

Oil & Gas Applications

- Handle waste water including emulsifications
- Remove heavy metals and other waste by-products resulting from coal/gas/oil production
- Reduce CO2 emissions when used with FNP absorption processes or miscible gas injection
- Clean-up holding tanks and ponds
- Recover marketable by-products (salts, metals, water)
- Provides an alternative to disposal wells

Allows for locating unit at the well head or disposal site and eliminates/reduces cost of transport

Zero Liquid Discharge (ZLD) solution through clean steam to atmosphere

Successful Treatment of Produced Water

- Fisk Neptune Processor has been successfully tested for breakdown of oil field produced water which further relates to oily barge ballast water, drill fluids, gas and oil pipeline entrained water and refinery process water.
- Fisk Neptune Processor pretreated waste water is subjected to hydro-cyclone vortex, skimming and biological oxidation as required for the conditioning necessary to meet wastewater discharge standards.
- Fisk Neptune Processor units are designed as portable, container modules with a minimal footprint to ease integration into existing plant layouts and are easily field deployable for batch or flow through site cleanup.

Treated Produced Water Output

- Total Suspended Solids (TSS) reduced to 10 ppm
- Total Dissolved Solids (TDS) reduced to 20 ppm
- Barium reduced to 10 ppm
- Hydrocarbons reduced to 5 ppm
- Hydrogen Sulfide (H2S) reduced to non-detectable
- Biological material reduced to non-detectable
- Output water can be processed to potable if desired
- Zero Liquid Discharge (ZLD)

Low Cost Producer

BTU 1 POUND WATER RAISED 1 DEGREE

- One gallon of water equals 8.34 pounds.
- Water to steam requires sensible and latent heat to achieve liquid to vapor.
- Sensible heat is energy necessary to raise liquid water from current temperature to 212 degrees.
- Latent heat is the energy necessary to turn a liquid to a vapor at 212 degrees.
- To distill 1 gallon water 8.34 pounds requires 9358 BTUs.

ENERGY RECOVERY PROCESSES

- Natural gas 1000 BTUs per cubic foot $3.00 per 1000 cubic feet
- Cost per gallon without recovery process equals per barrel cost $ 1.18 without energy recovery processes.
- This reflects a 100 % thermal transfer which this technology employs.
- The processes involved can return significant volumes of energy to the process.
  - Convective heat accounts for approximately 40% of the energy processed through the burner.

Costs are significantly reduced where flare gas is available and/or oil recovery allows for cost offsets.

Environmental Impact

ZERO LIQUID DISCHARGE

- Fisk Neptune Processor is a Zero Liquid Discharge (ZLD) solution.
- Treated water to potable can be released as clean steam, and generally will not require any special permitting.
- Recovered hydrocarbons are stored and sold to secondary markets
- Recovered material and salt is dried and available for disposal to appropriate landfills or sold to commodity markets (e.g. road salt).
- System monitors influent and effluent via remote SCADA system.

ENVRIONMENTAL IMPACT

- Unit is mobile and can be placed near the wellhead geography thereby reducing or eliminating trucking.
- If water is taken to potable and released as steam, only solids remain thereby eliminating any need for liquid waste removal.
- Where permissible, environmental discharge is an option if treated to potable.
- Units can be used to produce clean brine and potable water for mixing operation on site for reuse in fracking.

Eliminating ponds and/or disposal wells mitigates contingent liabilities for the producer while benefiting the environment.

Our Competitive Difference

- The Fisk Neptune Processor, patents pending, is unique in the industry as the unit can be tuned to water processing requirements based on the chemistry of that water.
- We believe the FNP unit's capabilities are unique and we are confident that our solution provides a better overall result.
  - Operating costs are lower with few moving parts to wear out.
  - Unit production costs are lower through standard design.
  - Production uses simplified manufacturing techniques allowing for ramp up against demand.
  - Fully mobilized platform and scalable

Fisk Neptune
processor

Neptune FS Global

For further information and discussion please contact Mark A. Skoda at:

Neptune FS Global

mark@neptunewrs.com

Phone: 901.277.4968

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Safe Harbor Provision

This report may contain forward-looking statements that involve risks, uncertainties, and assumptions. If any such risks or uncertainties materialize or if any of the assumptions prove incorrect, the results of The Neptune Water Remediation Services could differ materially from the results expressed or implied by the forward-looking statements we make. All statements other than statements of historical fact could be deemed forward-looking statements, including: any projections of product or service availability, customer growth, earnings, revenues, or other financial items; any statements regarding strategies or plans of management for future operations; any statements concerning new, planned, or upgraded services or developments; statements about current or future economic conditions; and any statements of belief.

The risks and uncertainties referred to above include - but are not limited to - risks associated with possible fluctuations in our financial and operating results; our rate of growth; interruptions or delays in our service or our Web hosting; breaches of our security measures; the financial impact of any previous and future acquisitions; the nature of our business model; our ability to continue to release, and gain customer acceptance of, new and improved versions of our service; successful customer deployment and utilization of our existing and future services; competition; the emerging markets in which we operate; our ability to hire, retain and motivate employees and manage our growth; changes in our customer base; technological developments; regulatory developments; litigation related to intellectual property and other matters; and general developments in the economy, financial markets, and credit markets.

The Neptune Water Remediation Services Group assumes no obligation and does not intend to update these forward-looking statements, except as required by law.

For Further Information Contact:
Mark A. Skoda
mark@neptunewrs.com
901.277.4968

POSEIDON Saltwater Systems transforms produced water into commercial products with ZERO waste

We use nature's hydrologic cycle to evaporate water as the final step. We have a suite of patents for our process, and look forward to opening wells stranded by the produced water challenge.

Come see us www.GoZero.US

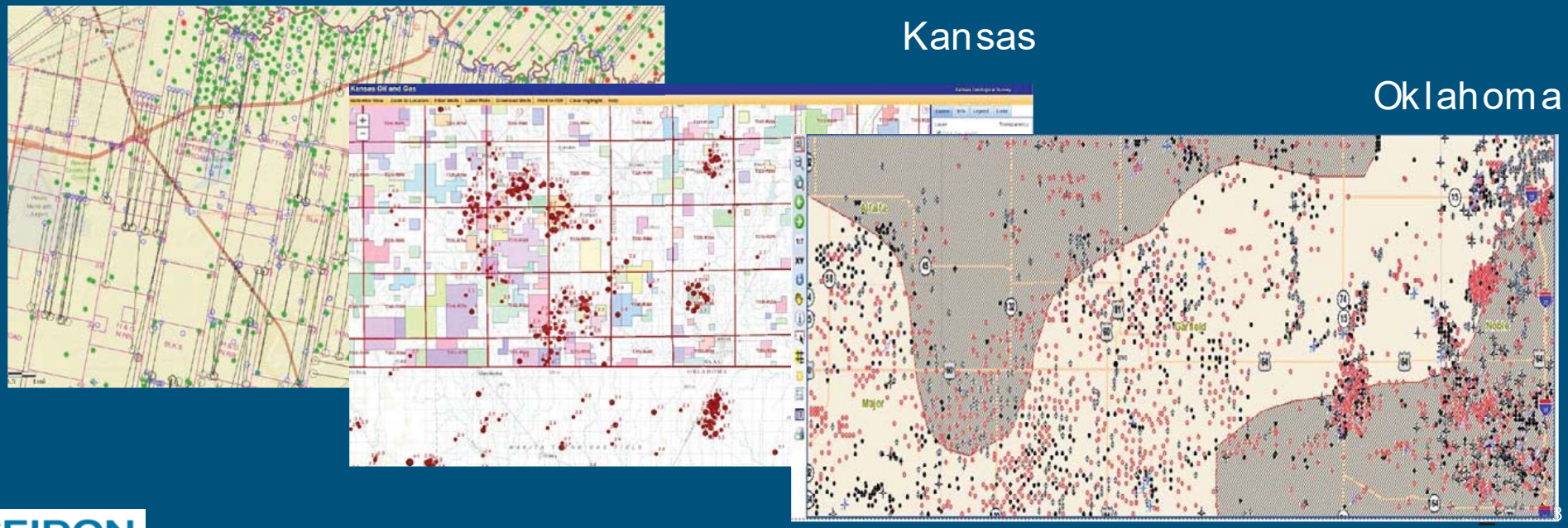
Status: we're deciding where to roll out next

Our industry faces challenges from Kansas to California …with the public at risk and production in peril.

Texas

Kansas

Oklahoma



POSEIDON
SALTWATER SYSTEMS, INC.

Our standards: We ask ourselves these questions

- 1. Do we get clean water?
- 2. How do we best contain the salt?
- 3. Who are the buyers for salt & other commercial byproducts?
- 4. What's the environmental impact?
- 5. How do we enhance existing industry infrastructure?

POSEIDON SALTWATER SYSTEMS, INC.

Our standards: Low cost, can be put anywhere

- 6. Is this flexible? Useful as infield? as a depot?
- 7. How do we grow to handle the volumes?
- 8. How does capital cost compare to other disposal methods?
- 9. How does cost per barrel compare?
- 10. What are the barriers to rolling out quickly?

We plan to stay the low cost provider

SECTION 3

Produced Water Re-use Scenarios

Table 3-1. Cost Estimates for Ten Produced Water Use Scenarios

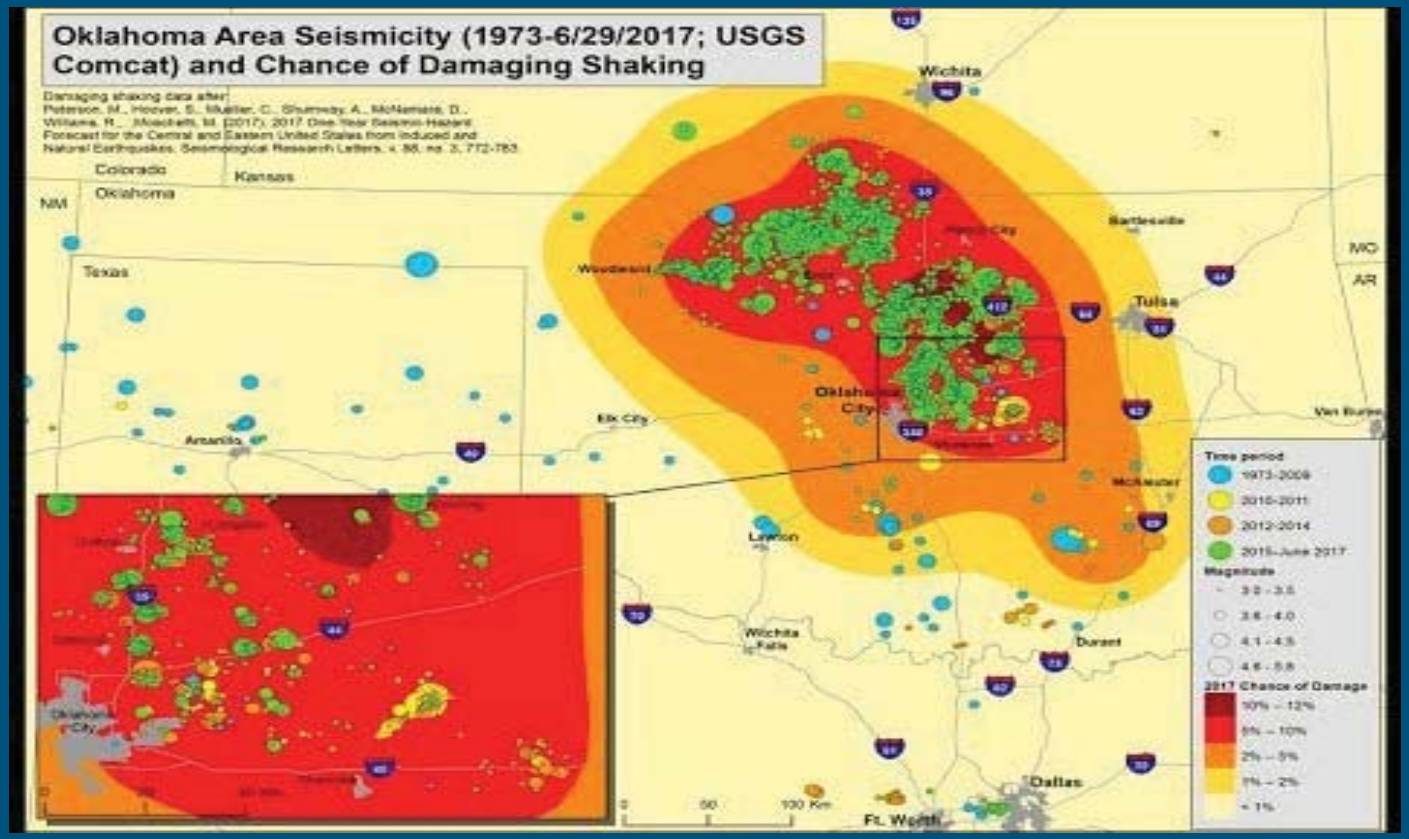
Oklahoma Water for 2060 Produced Water Re-use and Recycling Report

New Case	Case Description	Total Capital ($Millions)	Capacity BWPD	County	Assumed Wtr TDS (mg/L)	Normalized $/BW
1	Typical Source and Dispose - STACK & SCOOP	NA	NA	Central OK	NA	1.09
2	Oil and gas re-use (treatment cost only)	NA	NA	State-wide	NA	0.57
3	Clean Brine Transfer & treatment	208	200,000	Alfalfa	213,000	1.03
4	Evaporation - low TDS (SCOOP & STACK)	NA	20,000+	Blaine	17,000	1.66
5	Evaporation - high TDS (Miss. Lime)	NA	20,000+	Alfalfa	213,000	1.79
6	Desalination for Surface Discharge	22	15,000	Beckham	9,000	3.58
7	Desalination for Power Use	88	130,000	Pawnee	125,000	4.37
8	Desalination for Power Use	95	230,000	Seminole	180,000	4.43
9	Desalination for Industrial Use	35	30,000	Grant	227,00	7.41
10	Desalination for Surface Discharge	38	30,000	Grant	227,0	7.49

This is the Task Force report estimate, but Poseidon considers this estimate to be too high

POSEIDON SALTWATER SYSTEMS, INC.

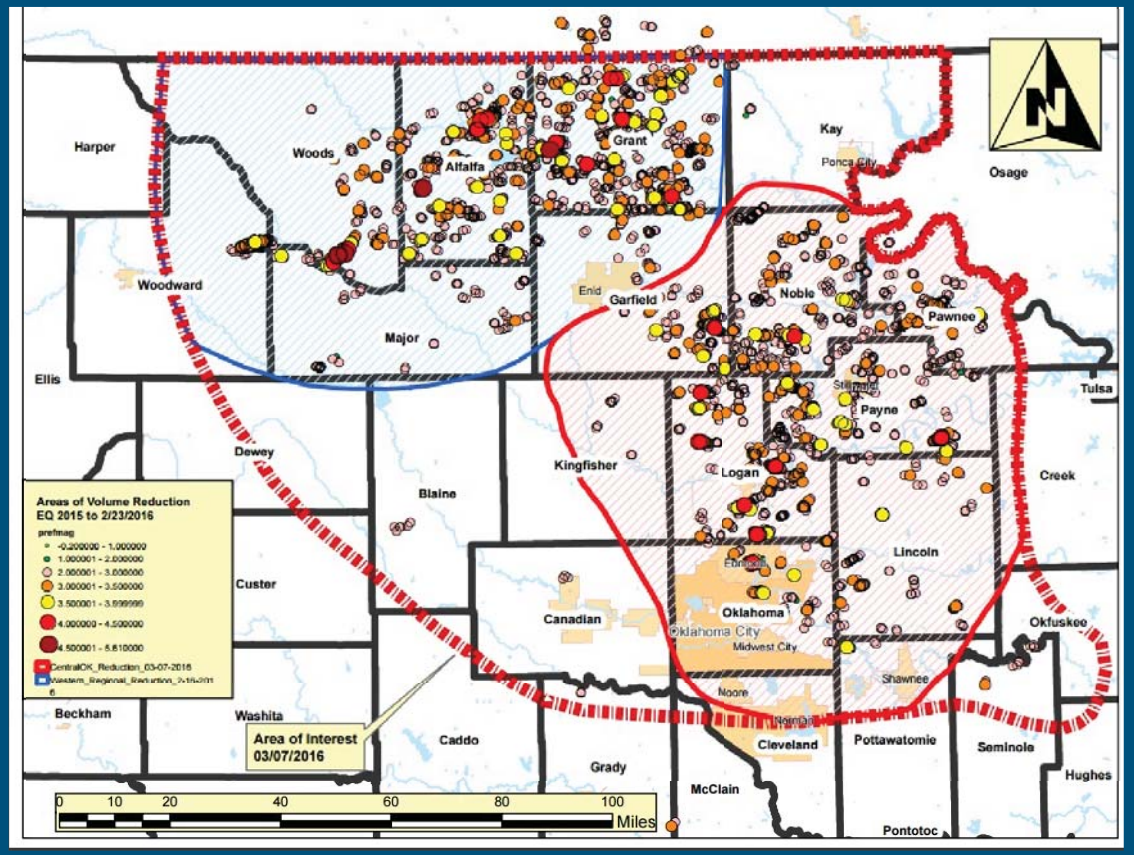
Other states are following the Oklahoma pattern
13 years of earthquakes in under 60 seconds



POSEIDON
SALTWATER SYSTEMS, INC.

Jobs at Poseidon plants are stable; we transform produced water boom or bust. We estimate 1000 jobs inside the redline.

With 1.3 billion in proven reserves in the Mississippi Lime, let's get stranded wells back online to boost the economy.



POSEIDON
SALTWATER SYSTEMS, INC.

INPUT:
Trucks or pipelines bring raw produced water to our plants

Stages in Poseidon's Water Treatment System

Untreated produced water

Oil skim removed

Skimmed Floc

Post water clarifying unit

After filtration

Dried salt

POSEIDON SALTWATER SYSTEMS, INC.

OUTPUT:
Poseidon turns waste water into commercial products

POSEIDON
SALTWATER SYSTEMS, INC.

Cycle vs. recycle/re-use

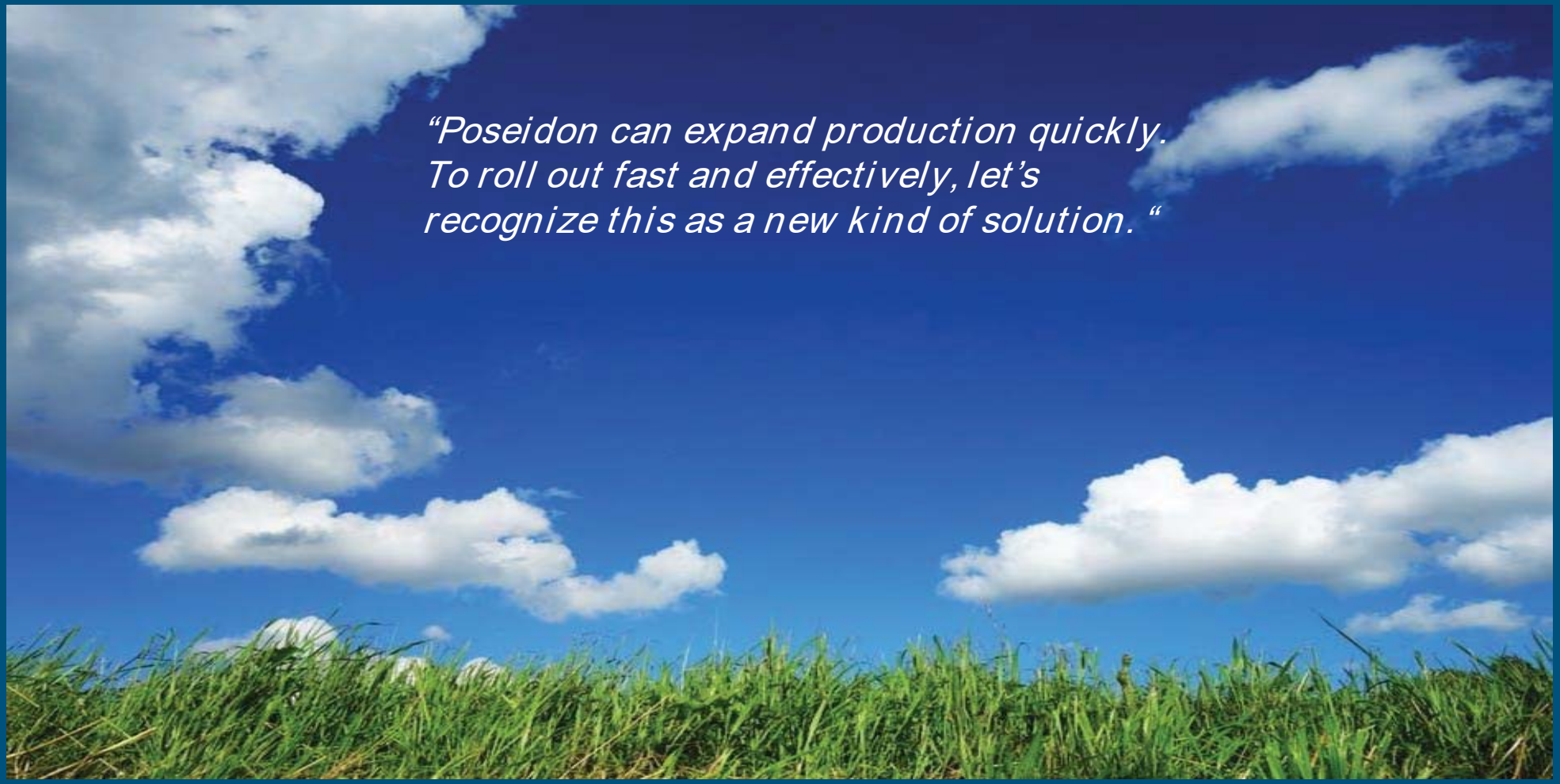
At Poseidon, we CYCLE:

—Poseidon collaborates with nature to use the hydrologic cycle

—We harness wind, humidity and temperature to work in our favor

— ZERO waste

—Therefore we never need pits, wells, or adjacent water



Come visit us www.GoZero.US Dennis Hudgens, Founder, CEO

purestream

A SWIRE COMPANY

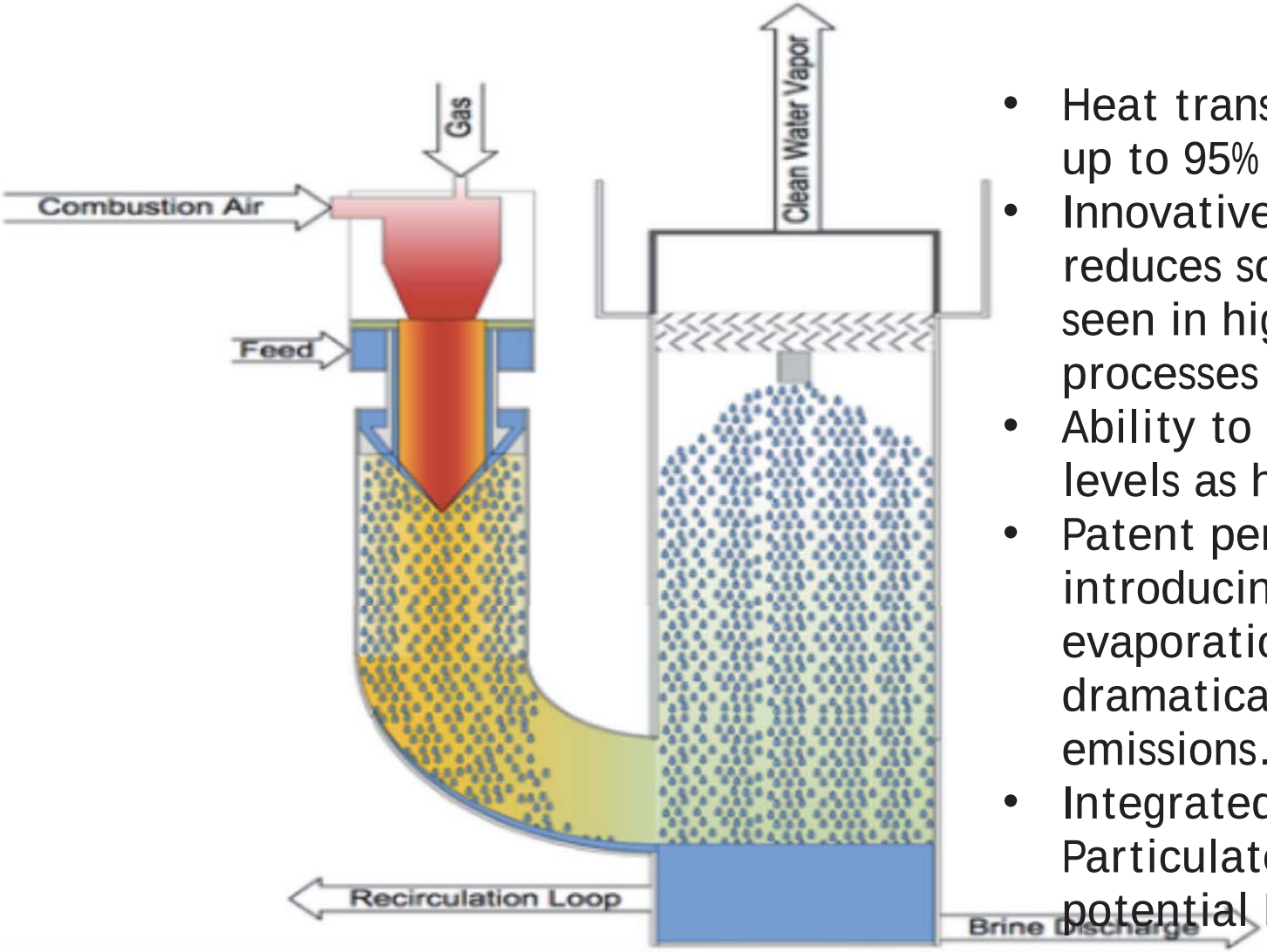
FLASH

EVAPORATION TECHNOLOGY

Unit Summary

- Self-contained, portable, modular unit.
- The modules are currently built with either an 8 MM BTU or 2 MM BTU burner.
- Modules can be connected in parallel to accommodate small to large treatment requirements.
- Burner capable of using natural gas or propane as fuel source
- 8 MM BTU
  - Daily Evaporation Rate: 350-400 bbls
  - 950-1150 BTU/cu. Ft
  - 480 V 3 Phase 150 amp electrical service
  - 80 kW power consumption
  - 140 CFM natural gas between 110-140 PSIG
  - Feed water minimum requirement of 5' of head pressure
- 2 MM BTU
  - Daily Evaporation Rate: 87-100 bbls
  - 50 kW power consumption

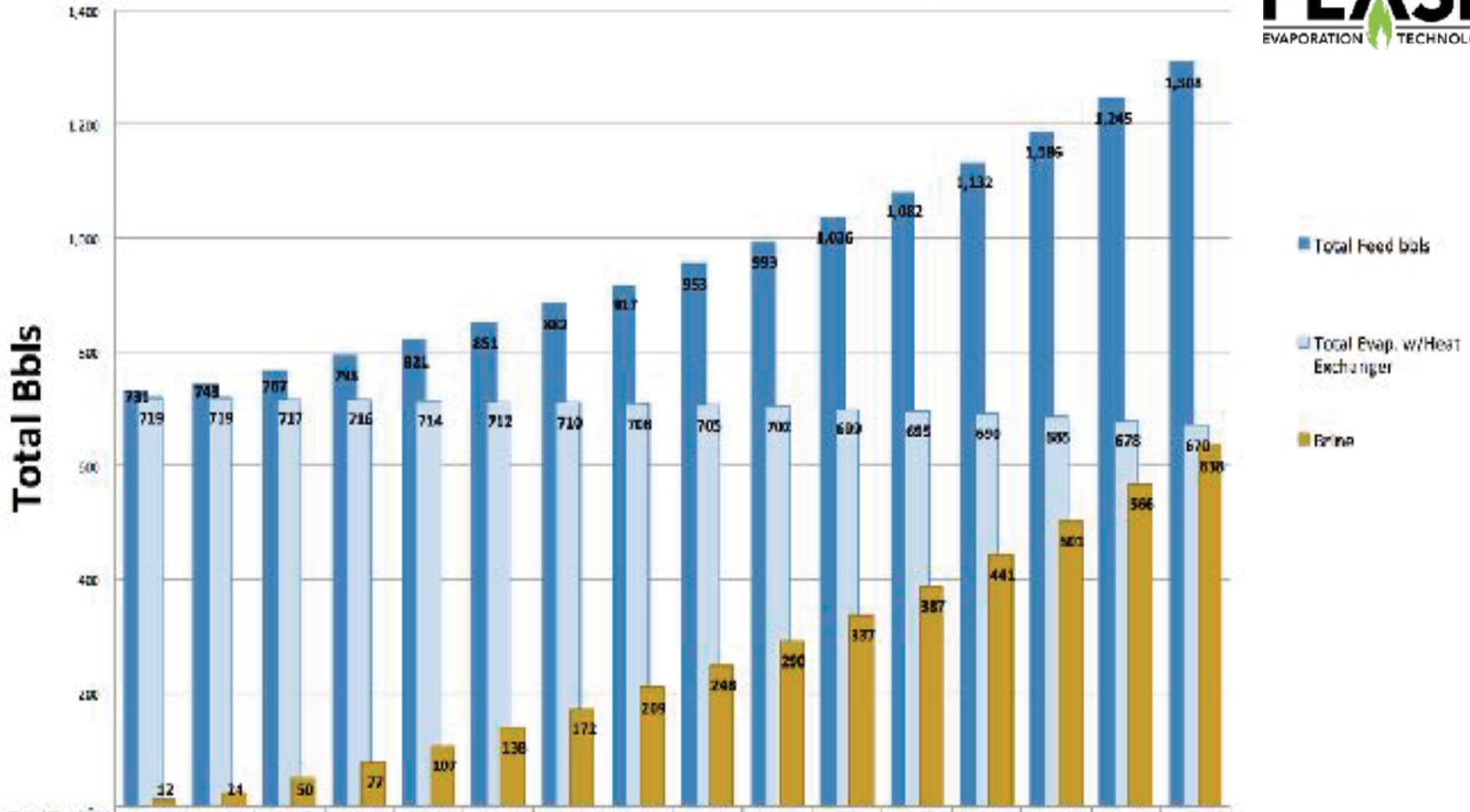
Process Diagram



- Heat transfer method that delivers up to 95% efficiency with natural gas
- Innovative burner design which reduces scaling potential typically seen in high TDS evaporation processes
- Ability to concentrate TDS up to levels as high as 300,000 mg/L
- Patent pending process for introducing water into the evaporation chamber which dramatically reduces contaminant emissions.
- Integrated Scrubbing that reduces Particulate Matter and other potential HAPs.

Total BBl Evaporated Vs. Feed TDS

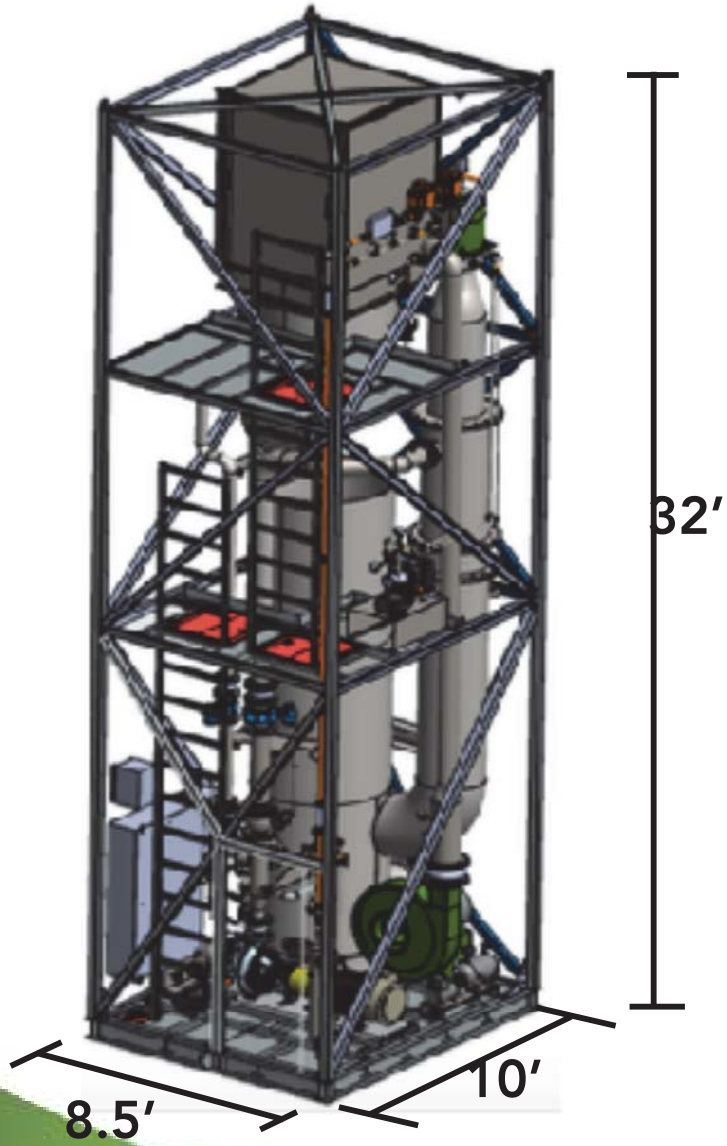
FLASH EVAPORATION TECHNOLOGY



Total Feed TDS	5,000	10,000	20,000	30,000	40,000	50,000	60,000	70,000	80,000	90,000	100,000	110,000	120,000	130,000	140,000	150,000
Total feed bbls	731	743	767	793	821	851	883	917	953	993	1,036	1,082	1,132	1,185	1,245	1,306
Total Evap. w/Heat Exchanger	719	719	717	716	714	712	710	708	705	702	699	695	690	685	678	670
Brine	12	24	50	77	107	138	172	209	248	290	337	387	441	501	566	638

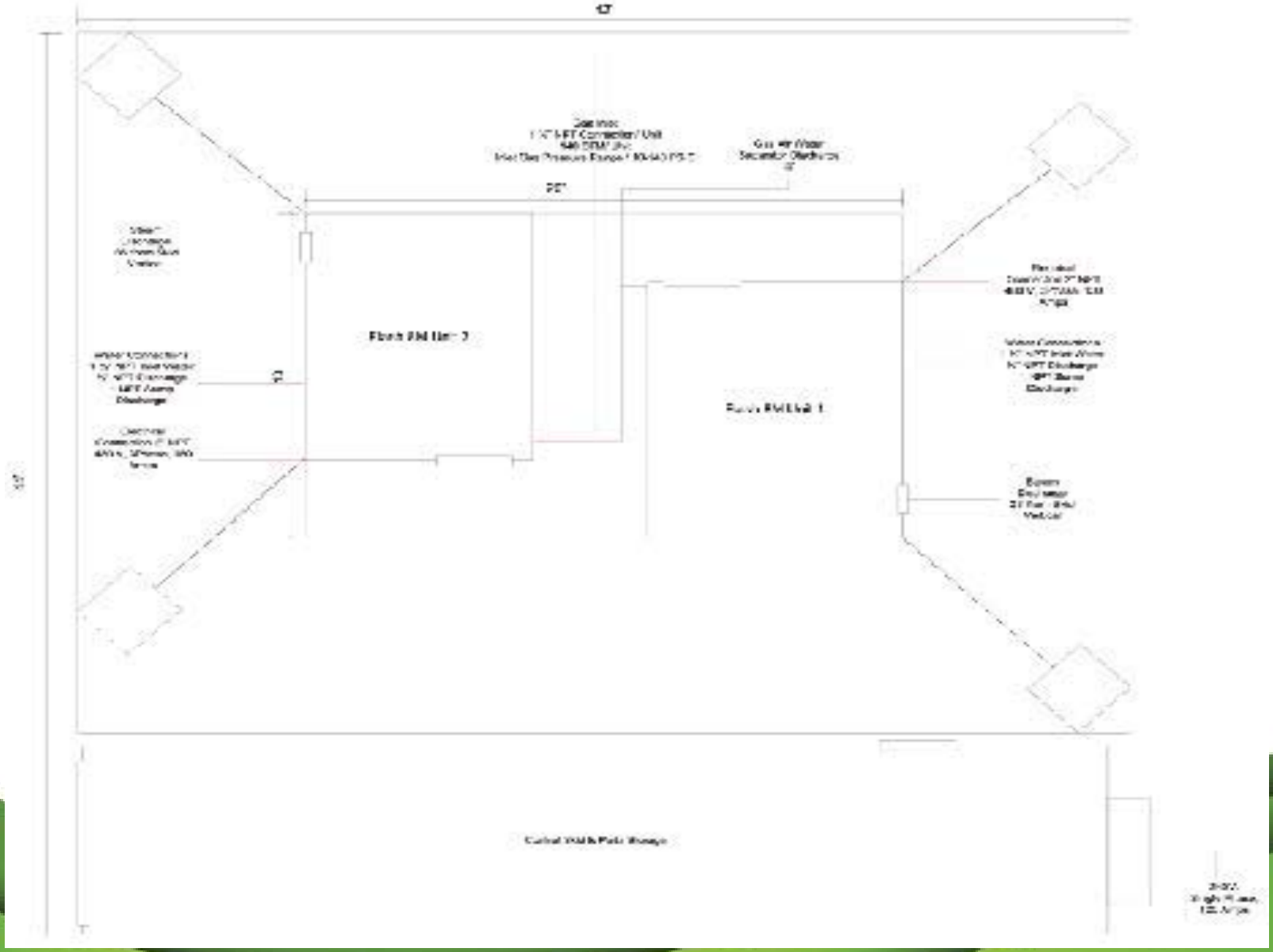
parcstream

8 MM BTU Footprint



- Each 8 MM BTU Flash unit utilizes additional outriggers with integrated concrete ballast blocks
- Total Unit Weight
  - 8 MM: 25,000 lbs.
  - 2 MM:
- Required Footprint with ballast outriggers:
  - 1 Unit: 30’ x 35’
  - 2 Units: 42’ x 35’
    (See next slide)
- Multiple units ganged together with brackets and pins
- Additional space required for spare parts storage and controls/data skid

Standard Two 8 MM BTU Setup



3rd Party Particulate Emissions Testing

- AST conducted investigative testing at the Purestream facility in Logan, Utah on August 31, 2017. Testing consisted of determining the emission rates of O2, CO2, SO2, NOx, CO, methanol, VOCs and PM from one water treatment evaporator unit. Produced

PM Results

Table 2-1
Summary of PM Results

Run Number	Run 1	Run 2	Run 3
Date	8/31/17	8/31/17	8/31/17
Test Condition	100,000 TDS Brine	200,000 TDS Brine	300,000 TDS Brine
Particulate Matter Data			
Filterable PM Concentration, grain/dscf	0.012	0.012	0.008
Filterable PM Emission Rate, lb/hr	0.024	0.027	0.016
Condensable PM Concentration, grain/dscf	0.0048	0.0064	0.0058
Condensable PM Emission Rate, lb/hr	0.010	0.015	0.012
Total PM Concentration, grain/dscf	0.016	0.018	0.014
Total PM Emission Rate, lb/hr	0.034	0.042	0.028

Emissions Testing Cont.

FLASH EVAPORATION TECHNOLOGY

Table 2-3
Summary of Methanol & Speciated VOC Results

Run Number	Run 4	Run Number	Run 4
Date	8/31/17	Date	8/31/17
Test Condition	Clean Water with BTEX	Test Condition	Clean Water with BTEX
Methanol Data		**Acetylene Data**	
Concentration, ppmvd	2.97	Concentration, ppmvd	0.00
Emission Rate, lb/hr	3.4E-03	Emission Rate, lb/hr	0.0E+00
Methane Data		**T-2-Butene Data**	
Concentration, ppmvd	1.38	Concentration, ppmvd	0.00
Emission Rate, lb/hr	5.5E-04	Emission Rate, lb/hr	0.0E+00
Ethane Data		**1-Butene Data**	
Concentration, ppmvd	0.30	Concentration, ppmvd	0.05
Emission Rate, lb/hr	0.0E+00	Emission Rate, lb/hr	1.5E-04
Ethylene Data		**C-2-Butene Data**	
Concentration, ppmvd	0.16	Concentration, ppmvd	0.00
Emission Rate, lb/hr	1.6E-04	Emission Rate, lb/hr	0.0E+00
Propane Data		**Isopentane Data**	
Concentration, ppmvd	0.30	Concentration, ppmvd	0.00
Emission Rate, lb/hr	0.0E+00	Emission Rate, lb/hr	0.0E+00
Propylene Data		**n-Pentane Data**	
Concentration, ppmvd	0.08	Concentration, ppmvd	0.00
Emission Rate, lb/hr	4.7E-05	Emission Rate, lb/hr	0.0E+00
Isobutane Data		**1,3-Butadiene Data**	
Concentration, ppmvd	0.30	Concentration, ppmvd	0.00
Emission Rate, lb/hr	0.0E+00	Emission Rate, lb/hr	0.0E+00
n-Butane Data		**Hexane Data**	
Concentration, ppmvd	0.30	Concentration, ppmvd	0.05
Emission Rate, lb/hr	0.0E+00	Emission Rate, lb/hr	1.6E-04

Table 2-2
Summary of SO_2, NOx, CO & NMVOC Results

Run Number	Run 1	Run 2	Run 3	Run 4
Date	8/31/17	8/31/17	8/31/17	8/31/17
Test Condition	100,000 TDS Brine	200,000 TDS Brine	300,000 TDS Brine	Clean Water with BTEX
Carbon Dioxide Data				
Concentration, % dry	12.0	11.8	11.5	10.7
Emission Rate, lb/hr	198.7	214.6	190.8	169.9
Oxygen Data				
Concentration, % dry	3.0	3.5	4.0	5.1
Nitrogen Oxides Data				
Concentration, ppmvd	42.1	96.0	45.9	31.1
Concentration, ppmvd @ 15% O_2	13.8	15.6	16.0	11.5
Emission Rate, lb/hr	0.07	0.09	0.08	0.05
Sulfur Dioxide Data				
Concentration, ppmvd	0.1	2.9	5.6	66.3
Concentration, ppmvd @ 15% O_2	0.03	1.0	2.0	24.5
Emission Rate, lb/hr	0.0002	0.008	0.014	0.15
Carbon Monoxide Data				
Concentration, ppmvd	30.6	32.4	34.0	14.4
Concentration, ppmvd @ 15% O_2	10.1	11.0	8.4	5.6
Emission Rate, lb/hr	0.02	0.04	0.03	0.01
Non-Methane Volatile Organic Compounds Data				
Concentration, ppmvd	0.0	4.0	2.8	1.2
Concentration, ppmvd @ 15% O_2	0.0	1.5	1.0	0.5
Emission Rate, lb/hr	0.000	0.009	0.005	0.002

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Emissions Testing Cont.

Methanol Results:

Feed Flow Rate	1.25	gpm
ppm Methanol in feed	1310	ppm
Total lbs/hr methanol in feed	0.82	lbs/hr
Exhaust rate	0.0034	lbs/hr
% of methanol out stack	0.41%	

Projection:

Feed Rate	1600	bbls/day
ppm Methanol	2100	ppm
Tons/year Methanol in	220	Tons/year in feed
Tons/year Out stack HAP	0.92	Tons/year Emissions

Two 8 MM BTU Annual Emissions

FLASH EVAPORATION TECHNOLOGY

Tons Per year Calculator

Testing Data Burner Size:	750,000	BTU
Treated BBL/Day	800	
Total Installation Burner Size:	16,000,000	BTU
# of 8M BTU units	2	
Fuel Type	NG	
Feed TDS	170,000	
Up time	100%	
Down Days/Yr	0	

*The following permit by rule parameters is for Pennsylvania

Emissions Testing DATA		Site Deployment Projected Emissions			
Constituent	**lb/hr**	**lb/yr**	**TPY**	**Exempt Status Requirement**	**Meets exempt status**
CO	0.033	6,167.04	3.08	<20 TPY	yes
NOx	0.08	14,950.40	7.48	<10 TPY	yes
Sox	0.008	1,495.04	0.75	<8 TPY	yes
VOC's	0.0046	859.65	0.43	<8 TPY	yes
PM10	0.031	5,793.28	2.90	<3 TPY	yes
HAPs					
Methanol	0.0034	635.39	0.32	<1 TPY	yes
Methane	0.00059	110.26	0.06	<1 TPY	yes
Ethane	0	-	-	<1 TPY	yes
Ethylene	0.00016	29.90	0.01	<1 TPY	yes
Propane	0	-	-	<1 TPY	yes
Propylene	0.000047	8.78	0.00	<1 TPY	yes
Isobutane	0	-	-	<1 TPY	yes
n-Butane	0	-	-	<1 TPY	yes
Acetylene	0	-	-	<1 TPY	yes
T-2-Butene	0	-	-	<1 TPY	yes
1-Butene	0.00015	28.03	0.01	<1 TPY	yes
C-2-Butene	0	-	-	<1 TPY	yes
Isopentane	0	-	-	<1 TPY	yes
n-Pentane	0	-	-	<1 TPY	yes
1,3-Buadiene	0	-	-	<1 TPY	yes
Hexane	0.00016	29.90	0.01	<1 TPY	yes
Total HAPs	0.004507	842.27	0.42	<2.5 TPY	yes

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Impacts Assessment

- Environmental Permits
  - Emissions permitting varies from state to state
  - Based on initial evaluation current unit emissions allow for approximately a 2000 bbl/day setup while meeting "permit by rule" parameters
  - Secondary containment is required forunits on site
  - No other environmental issues found based on previous and current field deployments
- Emissions Testing
  - Detailed water analysis on all Influent water streams
  - Continual vapor condensate testing is conducted on site by Purestream personnel
  - 3rd party particulate emissions testing to be performed on site as necessary

Expanding Enhanced Evaporation

- Customer Awareness
  - Proven/trusted alternative to current disposal options
  - Educate customer on potential CAPEX and OPEX savings achieved through Flash evaporation
    - Heavy Brine Reuse
    - Repurpose/Utilize wasted flare gas as supplemental energy source
    - Reduction of liability including potential class action lawsuits from seismic events
    - Reduction in disposal well associated CAPEX
      - Well
      - Storage
      - Pumps
      - Etc.
    - Decrease in trucking related expenses
  - Safety
    - Reduction in total trucking
  - Environmental
    - Reduction in spills potential

Experience

- Purestream is a water technology service provider founded in 2010
- Treated millions of bbls of water for reuse or disposal using proprietary technology developed in house
- Owned and operated multiple evaporation pond facilities
  - Tested and developed enhanced evaporation technology to maximize pond evaporation
- Current Sector Opportunities
  - Oil and Gas
  - Power Gen
  - Food and Beverage
  - Mining
  - Pulp and Paper
- Have been developing evaporation technology for past 5 years, during which time have:
  - Completed multiple extended field trials
  - Multiple unit improvements optimizing to live field conditions, including:
    - Emissions
    - Footprint
    - Scaling
    - Thermal efficiency

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VEOLIA

The MBD™ System

JP Welch, Director Upstream BD

WATER TECHNOLOGIES

Veolia: the leader in environmental solutions

The **only company** in the world able to cover the entire range of environmental solutions

$25.7 billion
163,000 employees

Activities:

Water

The global benchmark for water services and technologies

Energy

The global benchmark for energy optimization

Waste Management

The global benchmark for waste management and **resource recovery**

Veolia – Water Impact Index

Understanding and quantifying the impact on water resources is essential to maintain the sustainability and future prosperity of the planet: there is no substitute for water.

Are we operating within our Social License?

- ***No matter how much we believe in our project, we cannot self ascribe Social License. Trust must be earned and granted by the community of stakeholders***
  - ***Do we have broad stakeholder acceptance within the community?***
  - ***Does the project have legitimacy and credibility?***

Veolia evaporator technology represents a credible response to the increasing problem of water shortage and waste mitigation through water reuse and recycling.

Volume
- Water Quantity
- Volume Used, Extracted and Released

+

Stress
- Water Stress Index
- Local Hydrological context, freshwater scarcity

+

Quality
- Water quality – extracted and released

=

Water Impact Index

Water Impact Index expands on existing volume-based water measurement tools by factoring in three essential elements: quantity of water used, level of stress upon water resources and overall water quality. It provides additional parameters needed to make informed choices about effective water management.

MBD - What is it?

Application of the technology depends on treatment objectives.

- *Robust design, forced/plug flow circulation*
- *Bulk handling of solids*
- *Standardized modular design, +/- 2000 bpd*
- *Semi-permanent*
- *Heat recovery*

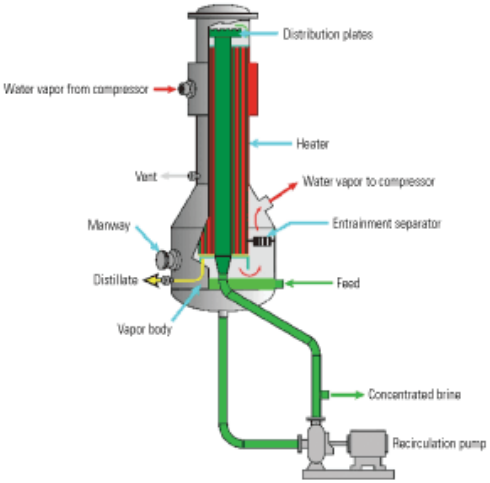
What it is not

- *Segregated salts*
- *Custom design*

The process begins with an analysis of the influent water and discharge specification. Pretreatment and emission recovery options expands application of the standard modular design.

Evap/ Crystallizer Variations

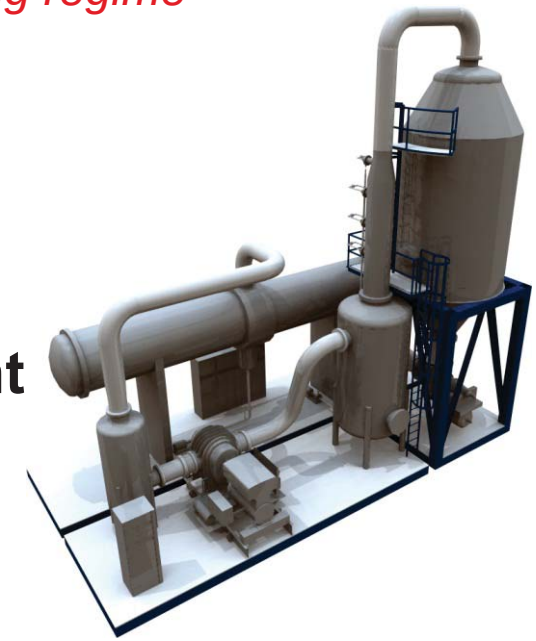
Type	Technical Design	Objective
Direct Contact	Utilize waste heat	Reduce Vol, min CapEx, higher OpEx
MVR	Falling film, distillate recovery	Higher CapEx, Lower OpEx via energy recovery
MBD	Forced flow, distillate recovery	Higher CapEx, Lower OpEx via energy recovery
Spray	Latent heat, low volume	Reduce Vol, very low CapEx, higher OpEx



MBD™ System – Environmental Considerations

Regulatory Compliance - Local, state and federal jurisdictions define MINIMAL siting, construction and operational standards.

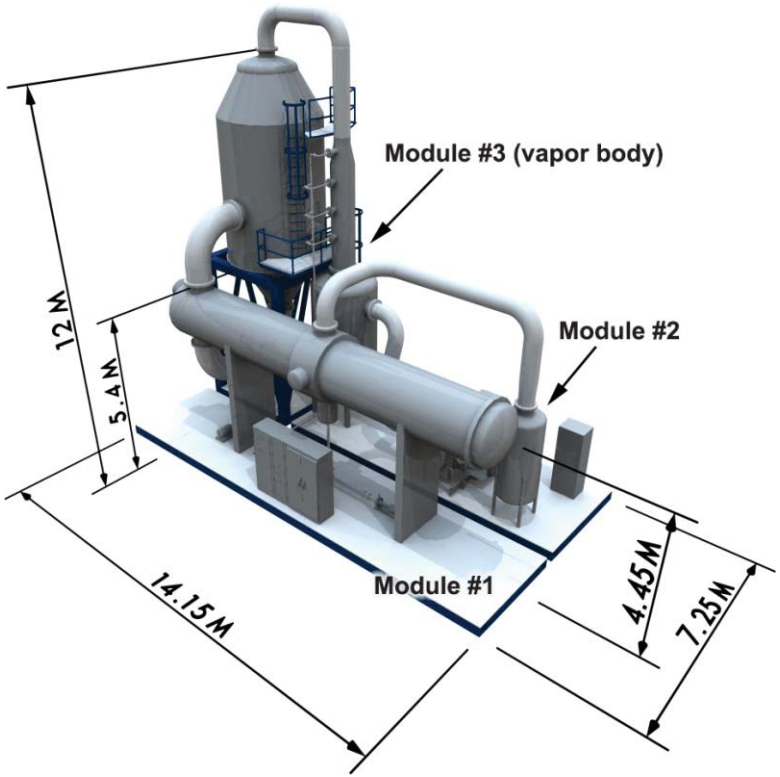
- **Influent and Effluent Evaluation**
  - *Influent quality defines system pretreatment and operating regime*
    - Materials of construction, VOCs, resource recovery
  - *Effluent management defined by*
    - Toxicity in gas (VRU), liquid and solid
    - Resource recovery
- **Site access: human, wildlife and containment**
- **Environmental and Community Benefits**
  - Reduced truck traffic
  - Opportunity for resource recovery or minimization – water/ salt
  - Transport fresh water versus salt water
  - Reduce disposal well volumes
  - Support fresh water management
  - Alternate frac water supply



MBD™ System – Brine Crystallizer System

Modular Bulldozer Design – CSG Produced Water

- **Modular Evaporation System**
  - *Supplied as (3) modules*
  - *Can be shipped by over-the-road transport*
  - *Rapid deployment, ability to relocate*
  - *Small footprint design*
  - *Mixed salt management supplied as skid*
- **Robust, Forced Circulation "Bulldozer" Design**
  - *High-efficiency, MVR driven*
  - *Capacity: 60 gpm*
  - *Scaling-resistant design*
  - *Corrosion resistant materials of construction*
- **Applications**
  - *Pond volume reduction*
  - *Eliminates need for new ponds*
  - *Pilot well testing*
  - *Zero Liquid Waste (ZLW) capabilities*



MBD™ System - Brine Crystallizer System

- **Ability to Treat Variable Feed Water Qualities or Feed Sources**
  - *Robust Forced Circulation design reduces concerns with scaling and corrosion*
  - *Can be moved to new sites with little modification*
  - *Reduces need for complex pretreatment*
- **Advantages**
  - *Modular system reduces transportation and installation costs*
  - *Significantly more cost effective than additional ponds*
  - *Eliminates additional costs of pond remediation*
  - *Environmentally friendly solution*
- **Risk Mitigation for CSG Sites**
  - *Mechanical solution for adverse rainfall conditions*
  - *Evaporation reduces EPA and local community concerns*
  - *Surety against project delays*

Challenges expanding Evap

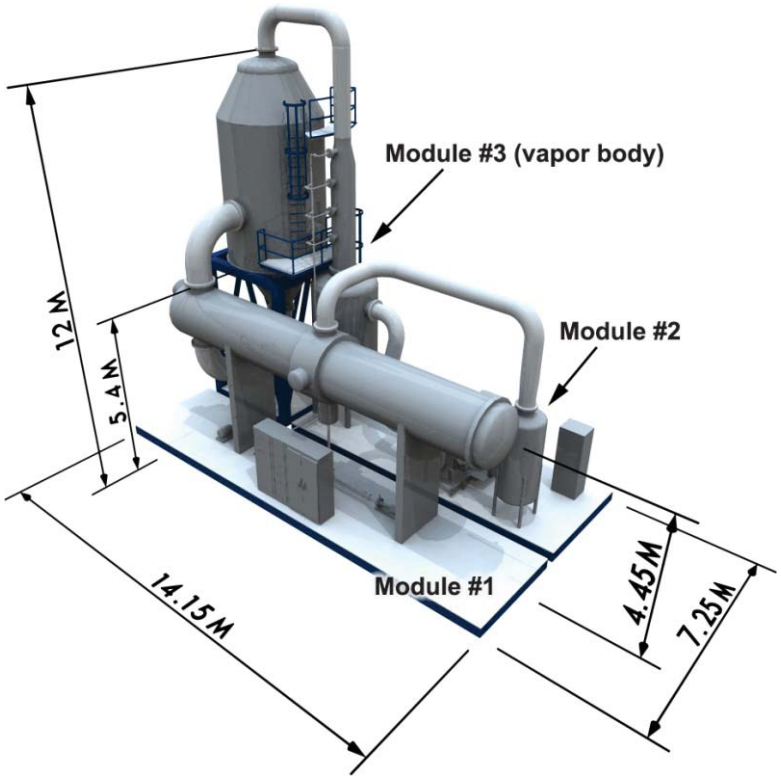
- Water quality can be too good
- Crystallization is energy intensive
- Liability of effluent steams (liquid/solid)

MBD™ System - Brine Crystallizer System

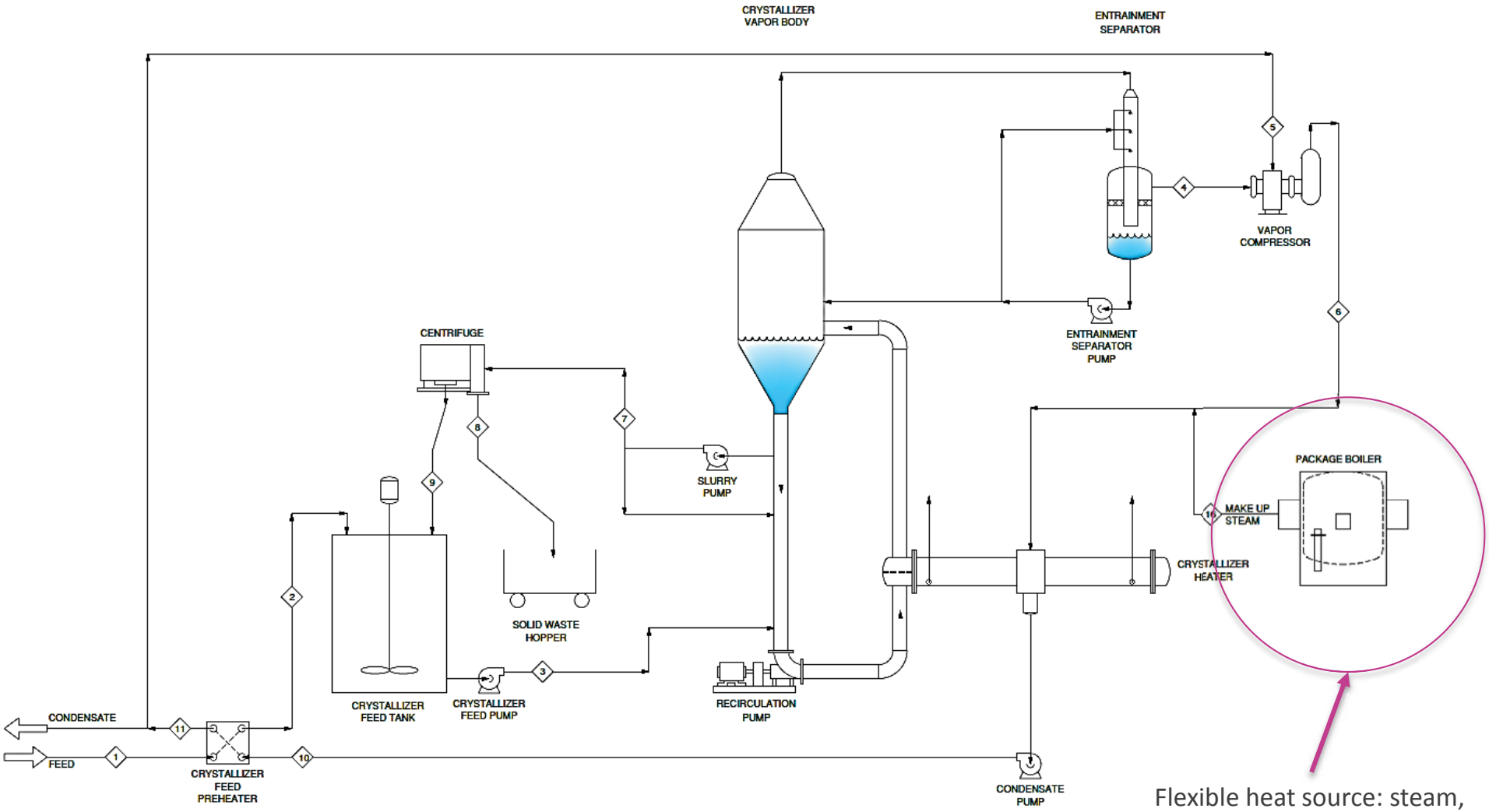
System Modules and Components

Components	Description
Module #1	Heater/heat exchanger
Module #2	Blower/compressor
Module #3	Crystallizer vapor body
Skid	Centrifuge / filter press

Ancillary Equipment Included	
Platforms and decking	Pumps
Instrumentation, control panels	Insulation
PLC and motor starters	Piping
Electrical, wiring	Valving



MBD™ System - Brine Crystallizer System



Flexible heat source: steam, electric, MVR, field gas, waste heat

Simplified flow diagram

MBD™ Design Advantages

- Can handle large quantities of suspended solids without plugging
- No internal distributors prone to plugging
- No areas where flow is slow or stagnant
- No need for clarification or filtration before evaporator
- No need for seeding since silica will precipitate in the flash tank, not as scale in the tubes

95%

Recovery in the Bulldozer Evaporator

Thermal Case Study

- Location: Canadian Oil Sands
- Treatment: SAGD Evaporator Blowdown Treatment
- Objective: (1) Volume Reduction to decrease off-site disposal cost
  (2) Increase water recycling for increased oil production

Case Study - Evaporator Blowdown Waste

Composite evaluations define influent quality and system design.

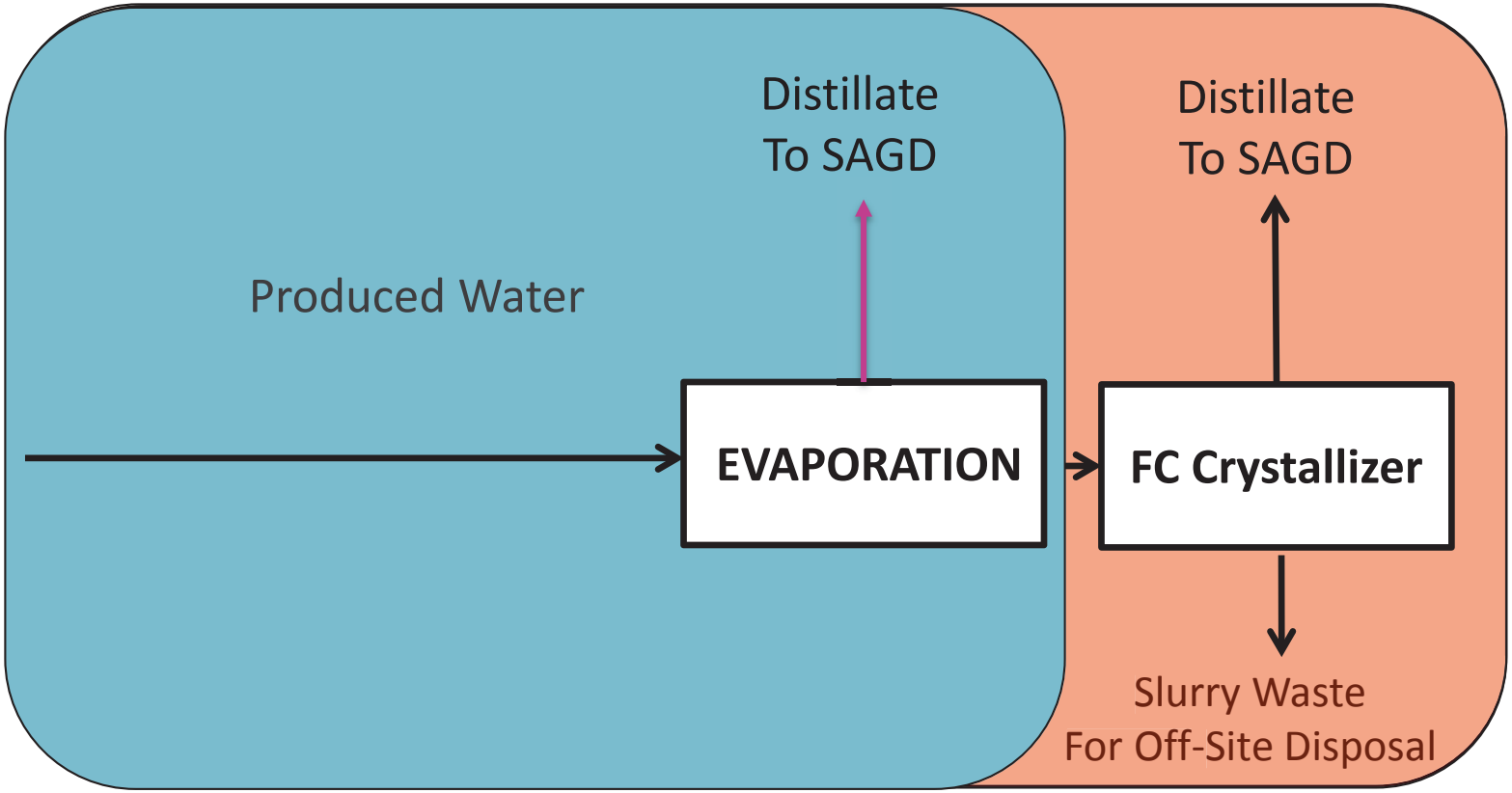
Table 1: Feed Design Chemistry

Component	Units	Design Composition
Temperature	°C	98 normal; 105 max.
Ca	mg/L	370
Mg	mg/L	20
Na	mg/L	50,500
K	mg/L	905
Al	mg/L	1.44
Sb	mg/L	0.12
As	mg/L	5.29
Ba	mg/L	19.6
B	mg/L	875
Cd	mg/L	0.00079
Fe	mg/L	7
Mo	mg/L	0.78
Se	mg/L	0.101
Cl	mg/L	50,000; 60,000 max.
NO_2	mg/L	795
SO_4	mg/L	532
F	mg/L	45
Br	mg/L	146
CO_3	mg/L	11842
SiO_2	mg/L	6,000; 9,000 max.
TIC	mg/L	2370
TDS	mg/L	109200; 135,000 max.
pH		12.6

Case Study - Evaporator Blowdown Waste

Parameter	Case	Comment
Capacity	1500 BPD waste from existing evaporator	
Technology Selected	Forced Circulation (FC) Evaporation	Forced Circulation required due to the bulk precipitation of NaCl when concentrated
Energy source	Electricity Compressor Driven Mechanical Vapor Recompression (MVR)	800 HP compressor
Water Recovery	80%	Concentrates feed up to 60% TS
Evaporator Blowdown	Off site disposal of 60% slurry	

Case Study - Volume Reduction



Economics:

300 BPD waste disposal

$12/barrel disposal cost

<u>$110,000/month disposal cost</u>

= $ 4.7 MM/year savings

Module Installation at Site

Final Installation

West Virginia, CoLD® Crystallization

Thank you for your kind attention

JP Welch
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832-876-2459
James.Welch@Veolia.com

Appendix B
Water Quality Technical Memorandum and Appendixes

JACOBS

Memorandum

Subject	**Produced Water Quality Mississippi Lime, STACK and SCOOP**
Project Name	Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios
From	Jacobs Engineering Group, Inc.
Date	June 2019

1. Produced Water Quality Mississippi Lime, STACK and SCOOP

This sampling effort was conducted as part of the Feasibility Study to further understand potential impacts from select alternative management strategies of produce water, and in support of OWRB's goal to reduce deep-well injection volumes and potential associated seismicity in the state.

1.1 Objectives

Due to a lack of publicly available data, the objective of the sampling effort was to collect representative produced water samples from the Mississippi Lime and STACK plays to provide a dataset to characterize the produced water qualities which can be used in future evaluations for scaling potential and compatibility with formation and hydraulic fracturing operations.

1.2 Sampling Area

Produced water sampling included STACK and SCOOP play and the Mississippi Lime play. All samples were collected from the Rich 1-32 Salt Water Disposal (SWD) facility near Woods County, Oklahoma. This facility received waters for deep-well disposal from multiple counties and multiple formations. The samples were collected by SWD facility staff and overseen by OWRB staff.

1.3 Produced Water Investigation Procedures

1.3.1 Produced Water Sampling and Characterization

Seven samples were collected from tanker trucks at the time of unloading at the SWD facility. One sample was taken from a 400-barrel (bbl) storage tank at the facility. The residence times of the produced water taken from the tanker trucks was approximately 6 to 12 hours after extraction from the well. The residence time of the produced water in the storage tank was approximately an additional six hours. Sample name, formation origin, lab identification number, and time of sampling event are presented in Table 1.

Samples 1-6 and 8 were taken from the tanker trucks from a 4-inch butterfly valve fitted with a 1-inch reducer valve. Water was dispensed from these valves directly into a dedicated, 1-liter (L) laboratory-certified clean glass jar (provided by TestAmerica Laboratories, Inc. [TestAmerica]) and decanted by hand into sample bottles. Sample 7 was taken from a 400-bbls fiberglass tank on-site. Here, produced water was dispensed directly from a 1-inch tank valve into a dedicated, 1-L laboratory-certified clean glass jar (provided by TestAmerica) and decanted by hand into sample bottles. Produced water samples were placed in a cooler on ice, chilled to approximately four degrees Celsius, and transported under chain of custody to TestAmerica, Nashville, Tennessee, for analysis.

Table 1. Water Quality Samples

Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

Sample #	Location	Formation	Date sampled	Lab ID
1	Woods Co.	STACK (Upper Osage)	7/25/18 12:58	490-156280-1
2	Woods Co.	Mississippi Lime (deep)	7/31/18 9:00	490-156673-1
3	Woods Co.	STACK (Chester)	7/31/18 10:00	490-156682-1
4	Woods Co.	STACK (Meramac)	7/31/18 10:30	490-156688-1
5	Alfalfa Co.	Mississippi Lime (deep)	8/30/18 12:30	490-158404-1
6	Alfalfa Co.	Mississippi (not Lime)	8/30/18 11:00	490-158407-1
7	400-bbls storage tank	Salt Water Disposal Well (mixture)	9/13/18 9:30	490-159189-1
8	Woods Co.	STACK (Lower Osage)	9/13/18 10:30	490-159194-1

1.3.2 Produced Water Analysis

The analytical methods used for water analysis can be found in Table 2. Produced water samples were analyzed for Target Analyte List (TAL) metals, which are listed in Table 4 (mercury, boron, and silica were not measured by the lab) by United States Environmental Protection Agency (USEPA) Method 200.7; hardness as calcium carbonate ($CaCO_3$) by Standard Method SM 2340B; alkalinity and bicarbonate by Standard Method SM 2320B; phosphorous by USEPA Method 365.4; TDS by Standard Method SM 2540C; pH by Standard Method SM 4500 H+B; chloride, sulfate, bromide, fluoride, nitrate and nitrite by USEPA Method 300.0; benzene, toluene, ethylbenzene, and xylenes (BTEX) by SW846 method 8260B; diesel range organics (DRO) and gasoline range organics (GRO, C6-C10) by Oklahoma Department of Environmental Quality Method OK DRO and OK GRO, respectively; total organic carbon (TOC) by Standard Method SM 5310B; gross alpha/beta radioactivity by SW846 Method 9310; and gamma emitting radionuclides (that is NORM) by USEPA Method 901.1.

Table 2. Analytical Methods and Descriptors for Produced Water Quality Analysis.

Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

Analytical Method	Analyte Descriptor
200.7 Rev 4.4	Target Analyte List (22 ICP) no Hg
SM 2340B	Hardness as CaCO3 (calculated)
SM 2320B	Alkalinity & Bicarbonate
SM 2540C	Total Dissolved Solids
300.0	Chloride, Sulfate, Bromide, Fluoride
300.0	Nitrate & Nitrite
8260B	BTEX
OK DRO	Oklahoma DRO
SM 4500 H+B	pH
OK GRO	Oklahoma GRO (C6-C10)
SM 5310B	Total Organic Carbon (Average Duplicate)
9310	Gross Alpha/Beta (GFPC)
901.1	Gamma Spec NORM (no ingrowth)

1.3.3 Investigation-derived Waste Disposal

The Site was fully equipped with drains to collect and dispose of produced water spills and truck wash-downs. Any produced water not used for sample analysis was disposed of on-site using the facility disposal system.

1.4 Data Quality Verification

For the purposes of this assessment, data verification seeks to evaluate the completeness and correctness of the data generated through this investigation against the methodical and procedural requirements.

1.4.1 Data Quality Objectives

The objectives for this investigation were to obtain accurate and representative sample analysis of produced water from the STACK and SCOOP and Mississippi Lime plays. Therefore, a sample plan was prepared to ensure data quality objectives were met.

1.4.1.1 Produced Water Representativeness of Formations

To ensure that the data generated in this analysis were representative of produced water from each play, four (4) samples were collected from target geologic zones with in the STACK play and three (3) samples were collected from the target geologic zone with the Mississippi Lime play. Additionally, the team collected a sample from an on-Site storage tank to assess potential mixing of produced water from multiple plays.

1.4.1.2 Sample Quality Control Measures

To evaluate potential sample contamination introduced during transportation or collection of the sample, field blanks and trip blanks were required in the sample plan. Field blanks were required at a rate of one field blank per sampling event (BTEX only, one sample) and trip blanks were required for each volatile organic sample (eight samples) as provided by the TestAmerica. No field blanks were recorded or analyzed. Therefore, potential sample contamination during the collection of the samples cannot be evaluated, and this data quality objective was not met. Further, trip blanks included for two volatile organic samples (Sample 3 and 4) were reported as having been “analyzed with significant headspace in the sample container”. This indicates that the trip blanks were prepared incorrectly by TestAmerica or they were opened on Site. Therefore, the potential contamination introduced to VOC samples during transportation cannot be evaluated, and this data quality objective was not met.

All samples were transported under chain of custody, analyzed within hold time (with the exception of the required hold time for pH analysis and nitrate/nitrate analysis), and within temperature.

1.5 Data Quality Validation

For the purposes of this assessment, data validation seeks to evaluate the analytical quality of the data generated through this investigation, and is based upon the measurement quality objectives, as determined by TestAmerica.

1.5.1 Data Qualifiers

The following data quality non-conformities were reported by TestAmerica.

1.5.2 General Water Quality Results

- All samples for pH analysis were out of maximum holding time prior to analysis, and therefore may not be representative of the produced water at the time of sampling.
- Sample 5 TOC analysis the matrix spike/matrix spike duplicate (MS/MSD) recovery was outside acceptance limits, indicating potential matrix interference leading to likely sample bias. Additionally, the MS/MSD relative percent difference (RPD) exceeded the control limits, indicating a lack of sample homogeneity. Lack of homogeneity impacts the representativeness of the data from the analysis of the sample.

1.5.3 Major Ions/Trace Elements

- Nitrate/nitrite were prepped or analyzed beyond the specified holding time.
- Bromide and aluminum was found in the blank and sample; however, these were detected at levels less than 10x the sample concentration. Therefore, the concentrations detected in the samples should be assumed to be true.
- The RPD of the Laboratory Control Sample (LCS) and LCS Duplicate (LCSD) exceeded the control limits and the LCS or LCSD is outside acceptance limits for many of the analytes in Samples 7 and 8, indicating a low degree of precision and accuracy of the results.

1.5.4 DRO/GRO, BTEX Compounds

- For each sample TestAmerica was unable to perform a MS/MSD for DRO/GRO analysis. Therefore, any bias in the analysis cannot be determined.

1.5.5 NORM

- For each sample, gross alpha/beta detection goals could not be met due to sample dilution to eliminate matrix effects.
- For each sample analyzed for lead-201 using Method 901.1, the instrument was out of calibration range. Therefore, the results are estimated.
- For samples 1, 5, and 6 analyzed using Method 901.1, the relative percent difference and replicate error ratio was above the acceptance limit of for Ra-226. Therefore, the accuracy and precision of these results cannot be determined. The lab suspected non-homogeneity of the sample matrix, which impacts that the representativeness of the result of the sample concentration.

1.6 Produced Water Analyses Findings

The following is a presentation of the findings of the produced water sample analysis.

1.6.1 General Water Quality Results

The water quality results varied due to the water quality samples gathered from varying formations in different geography areas surrounding the SWD location. The produced water samples were hypersaline with TDS levels ranging from 86,800 to 212,000 mg/L. This range has lower TDS values compared to the 2017 PWWG Report for the Alfalfa and Woods counties (152,000 to 218,000 mg/L). Notably, the samples analyzed for this Study did not include Blaine and Kingfisher Counties where the median TDS values are substantially lower, as reported in the 2017 PWWG Report. The Blaine and Kingfisher TDS median values were reported 17,000 and 25,000 mg/L, respectively in the 2017 PWWG Report.

The analyses in this study included many elements beyond just the TDS. Hardness was high in most samples, ranging from 11,700 mg/L to 45,000 mg/L. The exception was the sample taken from the storage tank, which was only 34 mg/L. Bicarbonate alkalinity was measured between 36 mg/L to 259 mg/L. The pH was neutral (6 to 7 standard units) and total organic carbon was relatively low, between 18 to 157 mg/L. A summary of these findings can be found in Table 1.

According to one research team that attempted to aggregate recommended water quality needs for production well stimulation (Liden et al. 2018), the following constituents were above the recommended values: calcium, iron, and magnesium There appears to be a relationship between TDS levels and TOC, with the higher TDS samples having lower TOC levels. Total organic carbon, which represents the all the organic compounds, including those not measured specifically (e.g., petroleum hydrocarbons), ranged between 28 mg/L to 157 mg/L.

1.6.2 Major Ions/Trace Elements

The major ions and trace elements are dominated by chloride and sodium. All samples contained chloride concentrations that exceeded a suggested guideline level for production well stimulation (30,000 – 50,000 mg/L) (Liden et al. 2018). Sulfate levels were elevated in all samples (equal to or greater than approximately 300 mg/L).

Additionally, the following chemicals exceeded recommended values for production well stimulation: calcium, iron, and magnesium. Boron and silica were not measured by the lab. Antimony, beryllium, selenium, thallium, or vanadium were not detected in any sample. Nitrate and nitrite were not detected in any sample; however, the samples were prepped or analyzed beyond the specified holding time and therefore may not be representative of the water.

Many of the analytes in Samples 7 and 8 were determined to be inaccurate by TestAmerica due to suspected matrix interference and/or non-homogeneity within the laboratory controls. Further, aluminum and bromide were found in sample blanks, which indicate that the measured concentrations in the corresponding produced water samples may be due, in part, to laboratory contamination. A summary of these findings can be found in Table 2.

Sulfate levels were elevated, ranging from 299 mg/L to 705 mg/L. Barium concentrations were low, which may lead to sulfate being the dominant electron acceptor under anaerobic conditions for sulfate reducing bacteria, therefore favoring the proliferation of these microorganisms. An abundance of sulfate reducing bacteria may lead to hydrogen sulfide generation and biofouling.

Boron was not measured by TestAmerica (TAL metals), and therefore represents a data gap to the analysis for potential reuse within the oilfield of these produced waters.

1.6.3 DRO/GRO, BTEX Compounds

BTEX compounds were detected in each sample. Furthermore, each sample had a higher concentration of Diesel Range Organics (DRO, C10-C28) than Gasoline Range Organics (GRO, C6-C10), except for Samples 5, 6, and 8. Generally, GRO measures the concentration of volatile organic compounds versus DRO, which measures semi-volatile organic compounds. A summary of these findings can be found in Table 4.

Volatile and semivolatile organic compounds (VOC and sVOC) were detected in all samples. Sample 7 had the highest concentrations of BTEX compounds. Samples 1-4, and 7 had higher concentrations of DRO than GRO; whereas Samples 5, 6, and 8 had more GRO than DRO.

GRO represents the volatile range of the petroleum hydrocarbons in these samples, whereas DRO represents the semi-volatile range. GRO/DRO may indicate what fraction of the total petroleum hydrocarbons present will volatilize out of the produced versus that which will remain in the aqueous or suspended phase. Benzene, toluene, ethylbenzene, and xylenes (BTEX) are water soluble VOCs that are found in petroleum hydrocarbons. They are known to be toxic to humans and common exposure routes include ingestion and inhalation. The rate that VOCs volatilize depends on a number of physical parameters including temperature and surface area. However, if these waters are to be evaporated as a means of disposal, it would be important to consider VOC impacts to air quality. Furthermore, the SVOCs may be concentrated in residuals and should be addressed as part of disposal options.

1.6.4 Gamma Emitting Radionuclides

Radium-226 was detected in every produced water sample, except for Sample 5; however, Sample 5 did have measurable levels of other gamma emitting radionuclides. Sample 6 had the highest measured concentration of radium-226 at 1320 pCi/L (picoCuries per liter). Radium-228 was measured in each sample except Sample 6. TestAmerica indicated that the method (USEPA Method 901.1) used to measure NORM in all produced water samples may have been inhibited by matrix interference—primarily due to the potential presence of uranium-235—and recommends that these data be considered qualitative only. However, recent literature indicates that non-destructive high-purity germanium gamma spectroscopy techniques, such as that used in Method 901.1, are effective at determining radium levels in high-ionic strength produced water, where uranium-235 is low, as is typical for shale-gas produced water (Nelson et al. 2014). Uranium-235 was not detected in the produced water samples analyzed for this investigation.

Gross alpha/beta were non-detect for most samples, but, the minimum detection level was greatly elevated (i.e., actual concentrations may be as high as 2500 pCi/L) due to high residual mass from elevated TDS.

Total radium activity (Ra-226 + Ra-228) ranged from 61.3 pCi/L to 1320 pCi/L. Numerous other radionuclides were detected in the samples, including actinium-228, bismuth-214, lead-212 and 214, potassium-40, and thorium-232. The method detection limit for gross alpha/beta were elevated above potential concentrations of concern; therefore, the presence of gamma emitting radionuclides cannot be discounted in samples which measured "non-detect."

Radium levels were consistent with other produced water samples, such as those in the Bakken, which have total radium activity up to 1,700 pCi/L (Lauer et al.2016), and other non-Marcellus produced waters (median of 1,011 pCi/L) (Rowen et al. 2011). However, produced water from the Marcellus, which averages around 5,500 pCi/L (Rowen et al. 2011), has been measured up to 18,000 pCi/L. For comparison, industrial wastewater effluent discharge limit is 60 pCi/L for Ra-226 (Rowen et al. 2011). Moreover, radium can sorb to organic and clay material or co-precipitate with sulfate or carbonate minerals. Therefore, there is the possibility that radium will concentrate in the solids or scale minerals. Radium-bearing sludge or scales may exceed waste exemption values. While currently not defined in the state of Oklahoma, other states have placed these exemption values between 5-50 pCi/g (Smith et al. 1999). In addition to the analytical concentration of radionuclides detected and measured in these produced waters, it is important to note elevated method detection limit means the presence of NORM cannot be eliminated as being potentially present at concentrations of concern. Therefore, NORM potentially present at levels of concern must be considered in both residuals' management and scale precipitation.

A summary of these findings can be found in Table 4.

1.7 Water Quality Conclusions

The analysis of produced water collected from the SWD resulted in the following conclusions about the samples:

- While this sampling effort provides additional insight into the quality of the produced water, the Study was limited in scope and experienced challenges with the sampling and analysis which makes some of the data unreliable.
- Mississippi Lime TDS concentrations from Alfalfa and Woods Counties ranged from 86,000 to 210,000 mg/L range, which were 152,000 to 218,000 mg/L in the 2017 PWWG Report. Samples did not include Blaine and Kingfisher Counties, but the 2017 PWWG Report stated the TDS median values for those counties were 17,000 and 25,000 mg/L, respectively.
- All samples contained chloride concentrations that exceeded a suggested guideline level for production well stimulation (30,000 – 50,000 mg/L, Liden et al. 2018).
- Calcium, iron, and magnesium exceeded common recommended values for production well stimulation, but industry does not have consistent criteria among companies.
- Sulfate levels were elevated, ranging from 299 mg/L to 705 mg/L. Barium concentrations were low, which may lead to sulfate being the dominant electron acceptor under anaerobic conditions for sulfate reducing bacteria, therefore favoring the proliferation of these microorganisms. An abundance of sulfate reducing bacteria may lead to hydrogen sulfide generation and biofouling.
- Volatile and semivolatile organic compounds (VOC and sVOC) were detected in all samples. However, if these waters are to be evaporated as a means of disposal, it would be important to consider VOC impacts to air quality. Furthermore, the SVOCs may be concentrated in residuals and should be addressed as part of disposal options.
- Total radium activity (Ra-226 + Ra-228) ranged from 61.3 pCi/L to 1320 pCi/L.
- The method detection limit for gross alpha/beta were elevated above potential concentrations of concern; therefore, the presence of gamma emitting radionuclides cannot be discounted in samples which measured "non-detect."
- There is the possibility that radium will concentrate in the solids or scale minerals, therefore, radium-bearing sludge or scales may exceed waste exemption values.
- Additional water quality sampling, pilot testing and evaluations are recommended to further address the following concerns/risks associated with the produced water transfer pipeline and evaporation alternatives:
    1. The mixing of different formations' waters could potentially create scale precipitation that could create operational problems that may include solids buildup in pipelines, vessels and pumps.
    2. The risks of produced water spills and subsequent remediation.
    3. The water from Mississippi Lime could potentially negatively impact the performance of the new hydraulically fractured well where the reuse occurs. For the producing companies investing in explorations

and operations, any measurable reduction in well performance due to water quality would be risky. This risk may be partially mitigated by performing minimal treatment of the water to be used in the hydraulic fracturing.

4. The effectiveness and cost of the water treatment processes are impacted by the produced water quality.
5. Overspray beyond the evaporation area can resulting in soil contamination and/or reduction of air quality due to constituents of concern in produced water.
6. The amount and type of solids generated through evaporation and treatment (including naturally occurring radioactive material) are dependent on the produced water quality.
7. The potential for air emissions such as VOCs from evaporation systems.

Table 3. General Water Quality Results for Oklahoma Produced Water Samples

Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

General Water Quality	Sample 1		Sample 2		Sample 3		Sample 4		Sample 5		Sample 6		Sample 7		Sample 8	
	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q
Hardness as calcium carb. (SM 2340B)	11700		38800		12000		18100		32100		23700		34.3		45000	
Phosphorus, Total	0.716		1.98		0.2		0.149		ND (0.05)		ND (0.05)		2.68		ND (0.05)	
Alkalinity	114		108		259		115		40		50.7		125		35.8	
Bicarbonate Alkalinity as $CaCO_3$	114		108		259		115		40		50.7		125		35.8	
Total Dissolved Solids	113000		212000	E	86800		117000		174000		186000		136000		210000	E
Total Organic Carbon	54.4		28.4		108		55.5		**34.4**	**F1 F2**	54.7		157		18.1	
pH	7	HF	6.8	HF	6.8	HF	6.8	HF	6	HF	6.3	HF	7.1	HF	6.7	HF

34.4 Laboratory qualifier indicates data are not reliable

Qualifier Definitions:

E = Result exceeded calibration range.

F1 = MS and/or MSD Recovery is outside acceptance limits.

F2 = MS/MSD RPD exceeds control limit

HF = Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.

ND = Non-Detect (Method Detection Limit [MDL])

Q = qualifier

Table 4. Major Ions and Trace Elements for Oklahoma Produced Water Samples

Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

	Sample 1		Sample 2		Sample 3		Sample 4		Sample 5		Sample 6		Sample 7		Sample 8	
	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q	mg/L	Q
Aluminum	0.851		3.13	B	0.782	B	1.01	B	ND (0.05)		0.224		**ND (0.05)**	*	**0.115**	*
Arsenic	ND (0.043)		ND (0.043)		ND (0.043)		ND (0.043)		ND (0.086)		ND (0.086)		**ND (0.0086)**	*	**0.02**	*
Barium	0.614		1.56		2.87		2.59		5.59		2.1		**0.0123**	*	**23.9**	*
Cadmium	ND (0.0025)		ND (0.0025)		ND (0.0025)		ND (0.0025)		ND (0.005)		ND (0.005)		**ND (0.0005)**	*	**0.0027**	*
Calcium	3720		11900		3670		5380		9300		6920		**13**	*	**12800**	*
Chromium	ND (0.015)		0.018	J	ND (0.015)		ND (0.015)		ND (0.03)		ND (0.03)		**ND (0.003)**	*	**ND (0.003)**	*
Copper	ND (0.025)		0.054		0.0415	J	0.028	J	0.0096	J	0.0202		**ND (0.005)**	*	**0.0155**	*
Iron	13.9		146		19.8		8.79		14.4		27.7		**0.116**	*	**17.2**	*
Lead	ND (0.1)		0.104		0.0225	J	ND (0.01)		0.08		0.131		**ND (0.002)**	*	**0.0316**	*
Magnesium	591		2240		700		1140		2170		1550		**0.457**	J *	**3170**	*
Manganese	0.214		0.403		1.3		0.405		4.1		0.717		**0.0052**	J *	**1.63**	*
Nickel	ND (0.015)		0.036	J	ND (0.015)		ND (0.015)		ND (0.03)		0.032	J	**ND (0.003)**	*	**0.008**	J *
Potassium	486		559		120		479		509		305		**1.07**	*	**375**	*
Silver	ND (0.015)		0.046		ND (0.015)		ND (0.015)		ND (0.03)		ND (0.03)		ND (0.003)		ND (0.003)	
Sodium	34000		21500		26700		30600		36900		24800		**36**	*	**60900**	*
Zinc	ND (0.125)		3.11		ND (0.125)		ND (0.125)		ND (0.25)		ND (0.25)		**ND (0.025)**	*	**0.106**	*
Bromide	372		1710		331		381		2860	B	1580	B	711		1150	
Chloride	63400		136000		41900		62300		191000		210000		89800		142000	
Fluoride	3.07		3.64	J	18		5.61		14.8		ND (3)		5.49		ND (1.2)	
Sulfate	705		530		299		636		348		385		553		369	

[1] **Antimony, beryllium, selenium, thallium, vanadium were not detected in any samples**

3720 **Value exceeds recommended concentration for production well stimulation (Liden et al. 2018)**

0.0123 **Laboratory qualifier indicates data are not reliable**

Qualifier Definitions:

B = Compound was found in the blank and sample.

J = Result is less than the Reporting Limit (RL) but greater than or equal to the MDL and the concentration is an approximate value.

* = RPD of the LCS and LCSD exceeds the control limits and/or LCS or LCSD is outside acceptance limits.

Table 5. GRO, DRO, BETX Results for Oklahoma Produced Water Samples

Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

VOCs (Method 8260B)	Sample 1		Sample 2		Sample 3		Sample 4		Sample 5		Sample 6		Sample 7		Sample 8	
	µg/L	Q	µg/L	Q	µg/L	Q	µg/L	Q	µg/L	Q	µg/L	Q	µg/L	Q	µug/L	Q
Benzene	1730		444		1350		1160		432		482		2290		2100	
Ethylbenzene	217		138		71.2		68		5.89		6.43		351		139	
Toluene	1950		685		889		733		165		162		1840		1400	
Xylenes, Total	839		818		477		293		21.5		24.4		2440		417	
GRO (Method OK GRO)																
C6 - C10 OK	7050		856		3190		2510		4500		4520		8110		4970	
DRO (Method OK DRO)																
C10 - C28	8630		59100		116000		66100		1650		1440		16600		4310	

µg/ L = microgram(s) per liter

Table 6. Naturally Occurring Radioactive Material and Gross Alpha and Beta Results for Oklahoma Produced Water Samples

Feasibility Study of Potential Impacts of Select Alternative Produced Water Management and Reuse Scenarios

Naturally Occurring Radioactive Material (NORM) Method 901.1	Sample 1		Sample 2		Sample 3		Sample 4		Sample 5		Sample 6		Sample 7		Sample 8	
	pCi/L	Q	pCi/L	Q	pCi/L	Q	pCi/L	Q	pCi/L	Q	pCi/L	Q	pCi/L	Q	pCi/L	Q
Actinium-227	ND (139)	U	ND (138)	U	ND (115)	U	ND (247)	U	ND (165)	U	ND (180)	U	ND (192)	U	ND (169)	U
Actinium-228	150		197		122		105		61.3		ND (78.7)	U	165		130	
Bismuth-212	ND (264)	U	ND (242)	U	ND (201)	U	ND (350)	U	ND (341)	U	ND (272)	U	ND (283)	U	ND (289)	U
Bismuth-214	275		377		214		311		49.9		452		273		212	
Lead-210	ND (271)	U	ND (237)	U	ND (230)	U	ND (310)	U	ND (236)	U	ND (322)	U	ND (334)	U	ND (225)	U
Lead-212	25		35.7		55		ND (30.9)	U	ND (45.4)	U	ND (56.9)	U	38.3		ND (25.1)	U
Lead-214	234		420		194		372		69.2		479		296		212	
Potassium-40	383		476		ND (218)	U	402		ND (234)	U	ND (215)	U	391		272	
Protactinium-231	**ND (981)**	**U**	**ND (1070)**	**U**	**ND (883)**	**U**	**ND (1410)**	**U**	**ND (837)**	**U**	**ND (1250)**	**U**	**ND (1020)**	**U**	**ND (953)**	**U**
Radium-226	**721**	**G**	**648**	**G**	471	G	**757**	**G**	ND (549)	U G	**1320**	**G**	**677**		531	
Radium-228	150		197		122		105		61.3		ND (78.7)	U	165		130	
Thallium-208	ND (12)	U	ND (17.1)	U	15.8		ND (17.7)	U	ND (20.4)	U	ND (13.1)	U	ND (18.6)	U	ND (17.1)	U
Thorium-232	150		197		122		105		61.3		ND (78.7)	U	165		130	
Thorium-234	ND (362)	U	ND (297)	U	ND (251)	U	ND (551)	U	ND (531)	U	ND (321)	U	ND (334)	U	ND (311)	U
Uranium-235	ND (121)	U	ND (77.4)	U	ND (141)	U	ND (264)	U	ND (122)	U	ND (149)	U	ND (140)	U	ND (112)	U
Uranium-238	ND (362)	U	ND (297)	U	ND (251)	U	ND (551)	U	ND (531)	U	ND (321)	U	ND (334)	U	ND (311)	U
Gross Alpha / Beta (GFPC) Method 9310																
Gross Alpha	**ND (651)**	**U G**	**ND (1520)**	**U G**	**ND (765)**	**U G**	**725**	**G**	**ND (2310)**	**U G**	**ND (2550)**	**U G**	**ND (962)**	**U G**	**ND (1400)**	**U G**
Gross Beta	ND (364)	U G	**ND (931)**	**U G**	ND (352)	U G	ND (376)	U G	**ND (1840)**	**U G**	**ND (1800)**	**U G**	ND (416)	U G	**ND (739)**	**U G**

ND (1070) **Concentration or method detection limit is greater than 10x the Industrial Discharge Limit of 60 pCi/L (Rowen et al. 2011)**

Qualifier Definitions:

U = Result is less than the sample detection limit.

G = Sample Minimum Detectable Concentration (MDC) is greater than the requested RL.

ND = Non-detect (MDL)

pCi/L = picoCuries per liter

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
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Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-156280-1
TestAmerica Sample Delivery Group: D&B
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Dr. James Rosenblum

Jennifer Gambill

Authorized for release by:
8/14/2018 11:39:52 AM

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*The test results in this report meet all 2003 NELAC and 2009 TNI requirements for accredited parameters, exceptions are noted in this report. This report may not be reproduced except in full, and with written approval from the laboratory. For questions please contact the Project Manager at the e-mail address or telephone number listed on this page.**This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.*
Results relate only to the items tested and the sample(s) as received by the laboratory.

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-156280-1	D&B 1:00	Water	07/25/18 12:58	07/26/18 09:45
490-156280-2	Trip Blank	Water	07/25/18 00:01	07/26/18 09:45

Job ID: 490-156280-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-156280-1

Comments
No additional comments.

Receipt
The samples were received on 7/26/2018 9:45 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 1.3º C.

HPLC/IC
Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: D&B 1:00 (490-156280-1). Elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-532991 and analytical batch 490-533735.

Method(s) OK DRO: The following sample was diluted due to abundance of target analytes: D&B 1:00 (490-156280-1). As such, surrogate recoveries are below the calibration range or are not reported, and elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

General Chemistry
Method(s) SM 5310B: Due to the high concentration of Total Organic Carbon, the matrix spike / matrix spike duplicate (MS/MSD) for analytical batch 490-533246 could not be evaluated for accuracy and precision. The associated laboratory control sample (LCS) met acceptance criteria.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD
Method(s) 901.1: Gamma Prep batch 160-379088: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: D&B 1:00 (490-156280-1), (LCS 160-379088/2-A), (MB 160-379088/1-A), (180-80153-D-1-A) and (180-80153-D-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-379088: The following sample, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative. D&B 1:00 (490-156280-1).

Method(s) 901.1: Gamma Prep Batch: 160-379088: The relative percent difference (RPD 481 pCi/L) and replicate error ratio (RER 1.11 pCi/L) was above the acceptance limit of 40%/1 for Ra-226. Non-homogeneity of the sample matrix is suspected; the sample contains particulates not dissolved. The data have been reported. (180-80153-D-1-B DU)

Job ID: 490-156280-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

Method(s) 9310: Gross Alpha/Beta Prep Batch 160-381190: The gross alpha and beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: D&B 1:00 (490-156280-1), (180-79813-H-1-A) and (180-79813-H-1-D DU). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Definitions/Glossary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Qualifiers

GC/MS VOA

Qualifier	Qualifier Description
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.
E	Result exceeded calibration range.

GC Semi VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

HPLC/IC

Qualifier	Qualifier Description
E	Result exceeded calibration range.

General Chemistry

Qualifier	Qualifier Description
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.
F	Duplicate RPD exceeds the control limit

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: D&B 1:00

Date Collected: 07/25/18 12:58
Date Received: 07/26/18 09:45

Lab Sample ID: 490-156280-1

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	1730		50.0	10.0	ug/L			07/26/18 15:27	50
Ethylbenzene	217		50.0	9.50	ug/L			07/26/18 15:27	50
Toluene	1950		50.0	8.50	ug/L			07/26/18 15:27	50
Xylenes, Total	839		150	29.0	ug/L			07/26/18 15:27	50

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*99*		*70 - 130*		*07/26/18 15:27*	*50*
4-Bromofluorobenzene (Surr)	*102*		*70 - 130*		*07/26/18 15:27*	*50*
Dibromofluoromethane (Surr)	*93*		*70 - 130*		*07/26/18 15:27*	*50*
Toluene-d8 (Surr)	*100*		*70 - 130*		*07/26/18 15:27*	*50*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	7050		200	100	ug/L			07/30/18 18:50	10

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*83*		*70 - 130*		*07/30/18 18:50*	*10*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	8630		1850	927	ug/L		08/01/18 10:49	08/04/18 09:31	20

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*0*	*X*	*50 - 150*	*08/01/18 10:49*	*08/04/18 09:31*	*20*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	372		50.0	2.50	mg/L			07/26/18 20:00	50
Nitrate as N	ND		5.00	2.50	mg/L			07/26/18 20:00	50
Chloride	63400		5000	3500	mg/L			07/31/18 18:37	5000
Nitrite as N	ND		5.00	2.50	mg/L			07/26/18 20:00	50
Fluoride	3.07		2.00	1.20	mg/L			07/26/18 19:42	20
Sulfate	705		50.0	30.0	mg/L			07/26/18 20:00	50

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.851		0.100	0.0500	mg/L		07/27/18 14:48	07/30/18 18:20	1
Antimony	ND		0.0500	0.0250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Arsenic	ND		0.0500	0.0430	mg/L		07/27/18 14:48	08/01/18 14:51	5
Barium	0.614		0.0500	0.0250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Beryllium	ND		0.00400	0.00200	mg/L		07/27/18 14:48	07/30/18 18:20	1
Cadmium	ND		0.00500	0.00250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Calcium	3720		5.00	2.50	mg/L		07/27/18 14:48	08/01/18 14:51	5
Chromium	ND		0.0250	0.0150	mg/L		07/27/18 14:48	08/01/18 14:51	5
Cobalt	ND		0.0500	0.0250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Copper	ND		0.0500	0.0250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Iron	13.9		0.500	0.250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Lead	ND		0.250	0.100	mg/L		07/27/18 14:48	08/07/18 15:17	50
Magnesium	591		1.00	0.250	mg/L		07/27/18 14:48	07/30/18 18:20	1
Manganese	0.214		0.0750	0.0250	mg/L		07/27/18 14:48	08/01/18 14:51	5
Nickel	ND		0.0500	0.0150	mg/L		07/27/18 14:48	08/01/18 14:51	5

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: D&B 1:00

Date Collected: 07/25/18 12:58
Date Received: 07/26/18 09:45

Lab Sample ID: 490-156280-1

Matrix: Water

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Potassium	**486**		1.00	0.500	mg/L		07/27/18 14:48	08/07/18 10:24	1
Selenium	ND		0.500	0.250	mg/L		07/27/18 14:48	08/07/18 15:17	50
Silver	ND		0.0250	0.0150	mg/L		07/27/18 14:48	08/01/18 14:51	5
Sodium	**34000**		100	40.0	mg/L		08/08/18 11:20	08/09/18 10:48	100
Thallium	ND		0.500	0.250	mg/L		07/27/18 14:48	08/07/18 15:17	50
Vanadium	ND		0.0200	0.0100	mg/L		07/27/18 14:48	07/30/18 18:20	1
Zinc	ND		0.250	0.125	mg/L		07/27/18 14:48	08/01/18 14:51	5

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**11700**		10.0	5.00	mg/L			08/07/18 23:26	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	**0.716**		0.100	0.0500	mg/L		08/02/18 11:30	08/05/18 18:43	1
Bicarbonate Alkalinity as CaCO3	**114**		10.0	5.00	mg/L			07/30/18 13:36	1
Alkalinity	**114**		10.0	5.00	mg/L			07/30/18 13:36	1
Total Dissolved Solids	**113000**		1000	700	mg/L			07/27/18 18:29	1
pH	**7.0**	**HF**	0.1	0.1	SU			07/27/18 18:39	1
Total Organic Carbon	**54.4**		2.00	1.00	mg/L			08/01/18 15:58	2

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	10.5	U	96.3	96.3		139	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Actinium-228	**150**		33.0	36.2		33.6	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Bismuth-212	-61.0	U	160	160		264	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Bismuth-214	**275**		35.8	45.2		21.7	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Lead-210	107	U	187	188		271	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Lead-212	**25.0**		14.1	14.5		20.9	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Lead-214	**234**		33.1	41.1		28.3	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Potassium-40	**383**		141	146		142	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Protactinium-231	0.000	U	81.7	81.7		981	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Radium-226	**721**	**G**	227	258	125	247	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Radium-228	**150**		33.0	36.2		33.6	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Thallium-208	10.5	U	10.8	10.8		12.0	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Thorium-232	**150**		33.0	36.2		33.6	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Thorium-234	158	U	221	221		362	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Uranium-235	24.1	U	72.2	72.3		121	pCi/L	07/30/18 11:40	07/30/18 21:08	1
Uranium-238	158	U	221	221		362	pCi/L	07/30/18 11:40	07/30/18 21:08	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*07/30/18 11:40*	*07/30/18 21:08*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: D&B 1:00

Date Collected: 07/25/18 12:58
Date Received: 07/26/18 09:45

Lab Sample ID: 490-156280-1

Matrix: Water

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	467	U G	426	429	3.00	651	pCi/L	08/08/18 17:38	08/10/18 08:14	1
Gross Beta	295	U G	233	235	4.00	364	pCi/L	08/08/18 17:38	08/10/18 08:14	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: Trip Blank

Lab Sample ID: 490-156280-2

Date Collected: 07/25/18 00:01
Date Received: 07/26/18 09:45

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/08/18 17:15	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/08/18 17:15	1
Toluene	ND		1.00	0.170	ug/L			08/08/18 17:15	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/08/18 17:15	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*115*		*70 - 130*		*08/08/18 17:15*	*1*
4-Bromofluorobenzene (Surr)	*100*		*70 - 130*		*08/08/18 17:15*	*1*
Dibromofluoromethane (Surr)	*108*		*70 - 130*		*08/08/18 17:15*	*1*
Toluene-d8 (Surr)	*96*		*70 - 130*		*08/08/18 17:15*	*1*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-531609/6
Matrix: Water
Analysis Batch: 531609

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			07/26/18 13:11	1
Ethylbenzene	ND		1.00	0.190	ug/L			07/26/18 13:11	1
Toluene	ND		1.00	0.170	ug/L			07/26/18 13:11	1
Xylenes, Total	ND		3.00	0.580	ug/L			07/26/18 13:11	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*104*		*70 - 130*		*07/26/18 13:11*	*1*
4-Bromofluorobenzene (Surr)	*95*		*70 - 130*		*07/26/18 13:11*	*1*
Dibromofluoromethane (Surr)	*96*		*70 - 130*		*07/26/18 13:11*	*1*
Toluene-d8 (Surr)	*106*		*70 - 130*		*07/26/18 13:11*	*1*

Lab Sample ID: LCS 490-531609/3
Matrix: Water
Analysis Batch: 531609

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	18.15		ug/L		91	70 - 130
Ethylbenzene	20.0	21.45		ug/L		107	70 - 130
Toluene	20.0	19.95		ug/L		100	70 - 130
Xylenes, Total	40.0	43.18		ug/L		108	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*98*		*70 - 130*
4-Bromofluorobenzene (Surr)	*102*		*70 - 130*
Dibromofluoromethane (Surr)	*94*		*70 - 130*
Toluene-d8 (Surr)	*103*		*70 - 130*

Lab Sample ID: LCSD 490-531609/4
Matrix: Water
Analysis Batch: 531609

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	19.15		ug/L		96	70 - 130	5	12
Ethylbenzene	20.0	22.42		ug/L		112	70 - 130	4	12
Toluene	20.0	20.30		ug/L		101	70 - 130	2	13
Xylenes, Total	40.0	45.62		ug/L		114	70 - 132	5	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*100*		*70 - 130*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*
Dibromofluoromethane (Surr)	*95*		*70 - 130*
Toluene-d8 (Surr)	*101*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-156315-B-1 MS
Matrix: Water
Analysis Batch: 531609

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	20.12		ug/L		101	55 - 147
Ethylbenzene	ND		20.0	23.55		ug/L		118	65 - 139
Toluene	ND		20.0	21.82		ug/L		109	64 - 136
Xylenes, Total	ND		40.0	47.22		ug/L		118	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*99*		*70 - 130*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*
Dibromofluoromethane (Surr)	*96*		*70 - 130*
Toluene-d8 (Surr)	*103*		*70 - 130*

Lab Sample ID: 490-156315-C-1 MSD
Matrix: Water
Analysis Batch: 531609

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	20.41		ug/L		102	55 - 147	1	22
Ethylbenzene	ND		20.0	23.77		ug/L		119	65 - 139	1	18
Toluene	ND		20.0	21.79		ug/L		109	64 - 136	0	18
Xylenes, Total	ND		40.0	47.47		ug/L		119	69 - 132	1	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*100*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*95*		*70 - 130*
Toluene-d8 (Surr)	*102*		*70 - 130*

Lab Sample ID: MB 490-534615/6
Matrix: Water
Analysis Batch: 534615

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/08/18 13:18	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/08/18 13:18	1
Toluene	ND		1.00	0.170	ug/L			08/08/18 13:18	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/08/18 13:18	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*110*		*70 - 130*		*08/08/18 13:18*	*1*
4-Bromofluorobenzene (Surr)	*100*		*70 - 130*		*08/08/18 13:18*	*1*
Dibromofluoromethane (Surr)	*108*		*70 - 130*		*08/08/18 13:18*	*1*
Toluene-d8 (Surr)	*96*		*70 - 130*		*08/08/18 13:18*	*1*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: LCS 490-534615/3
Matrix: Water
Analysis Batch: 534615

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	24.09		ug/L		120	70 - 130
Ethylbenzene	20.0	21.29		ug/L		106	70 - 130
Toluene	20.0	21.34		ug/L		107	70 - 130
Xylenes, Total	40.0	42.31		ug/L		106	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*116*		*70 - 130*
4-Bromofluorobenzene (Surr)	*103*		*70 - 130*
Dibromofluoromethane (Surr)	*99*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Lab Sample ID: LCSD 490-534615/4
Matrix: Water
Analysis Batch: 534615

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	22.86		ug/L		114	70 - 130	5	12
Ethylbenzene	20.0	21.17		ug/L		106	70 - 130	1	12
Toluene	20.0	21.30		ug/L		107	70 - 130	0	13
Xylenes, Total	40.0	41.84		ug/L		105	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*116*		*70 - 130*
4-Bromofluorobenzene (Surr)	*103*		*70 - 130*
Dibromofluoromethane (Surr)	*97*		*70 - 130*
Toluene-d8 (Surr)	*97*		*70 - 130*

Lab Sample ID: 490-157045-B-1 MS
Matrix: Water
Analysis Batch: 534615

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	145		100	220.3		ug/L		76	55 - 147
Ethylbenzene	1640	E	100	1450	E 4	ug/L		-189	65 - 139
Toluene	640		100	581.3	4	ug/L		-59	64 - 136
Xylenes, Total	1510		200	1367	4	ug/L		-70	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*120*		*70 - 130*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*
Dibromofluoromethane (Surr)	*99*		*70 - 130*
Toluene-d8 (Surr)	*95*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-157045-B-1 MSD
Matrix: Water
Analysis Batch: 534615

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	145		100	220.7		ug/L		76	55 - 147	0	22
Ethylbenzene	1640	E	100	1462	E 4	ug/L		-177	65 - 139	1	18
Toluene	640		100	580.6	4	ug/L		-59	64 - 136	0	18
Xylenes, Total	1510		200	1364	4	ug/L		-71	69 - 132	0	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*116*		*70 - 130*
4-Bromofluorobenzene (Surr)	*102*		*70 - 130*
Dibromofluoromethane (Surr)	*99*		*70 - 130*
Toluene-d8 (Surr)	*95*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-532387/5
Matrix: Water
Analysis Batch: 532387

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			07/30/18 08:57	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*108*		*70 - 130*		*07/30/18 08:57*	*1*

Lab Sample ID: LCS 490-532387/4
Matrix: Water
Analysis Batch: 532387

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C6-C10 OK	200	183.4		ug/L		92	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*109*		*70 - 130*

Lab Sample ID: LCSD 490-532387/24
Matrix: Water
Analysis Batch: 532387

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK	200	182.9		ug/L		91	80 - 120	0	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*108*		*70 - 130*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-532991/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533735 — **Prep Batch: 532991**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		08/01/18 10:49	08/03/18 18:45	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*103*		*50 - 150*	*08/01/18 10:49*	*08/03/18 18:45*	*1*

Lab Sample ID: LCS 490-532991/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533735 — **Prep Batch: 532991**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	504.9		ug/L		101	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*103*		*50 - 150*

Lab Sample ID: LCSD 490-532991/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533735 — **Prep Batch: 532991**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	514.1		ug/L		103	80 - 120	2	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*99*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-531837/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531837

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			07/26/18 12:06	1
Chloride	ND		1.00	0.700	mg/L			07/26/18 12:06	1
Fluoride	ND		0.100	0.0600	mg/L			07/26/18 12:06	1
Sulfate	ND		1.00	0.600	mg/L			07/26/18 12:06	1

Lab Sample ID: LCS 490-531837/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531837

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	10.09	E	mg/L		101	90 - 110
Chloride	10.0	9.390		mg/L		94	90 - 110
Fluoride	1.00	0.9694		mg/L		97	90 - 110
Sulfate	10.0	9.674		mg/L		97	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-531837/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531837

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	10.08	E	mg/L		101	90 - 110	0	20
Chloride	10.0	9.367		mg/L		94	90 - 110	0	20
Fluoride	1.00	0.9708		mg/L		97	90 - 110	0	20
Sulfate	10.0	9.671		mg/L		97	90 - 110	0	20

Lab Sample ID: 490-156277-E-23 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531837

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	0.394	J	10.0	10.99	E	mg/L		106	80 - 120
Fluoride	0.351		1.00	1.436		mg/L		108	80 - 120

Lab Sample ID: MB 490-531838/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531838

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			07/26/18 12:06	1
Nitrite as N	ND		0.100	0.0500	mg/L			07/26/18 12:06	1

Lab Sample ID: LCS 490-531838/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531838

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	0.9402		mg/L		94	90 - 110
Nitrite as N	1.00	0.9386		mg/L		94	90 - 110

Lab Sample ID: LCSD 490-531838/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531838

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	0.9442		mg/L		94	90 - 110	0	20
Nitrite as N	1.00	0.9397		mg/L		94	90 - 110	0	20

Lab Sample ID: 490-156277-E-23 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 531838

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	0.755		1.00	1.793		mg/L		104	80 - 120
Nitrite as N	ND		1.00	1.074		mg/L		107	80 - 120

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: MB 490-532682/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532682

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			07/31/18 13:11	1
Chloride	ND		1.00	0.700	mg/L			07/31/18 13:11	1
Fluoride	ND		0.100	0.0600	mg/L			07/31/18 13:11	1
Sulfate	ND		1.00	0.600	mg/L			07/31/18 13:11	1

Lab Sample ID: LCS 490-532682/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532682

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Chloride	10.0	9.672		mg/L		97	90 - 110
Fluoride	1.00	0.9854		mg/L		98	90 - 110
Sulfate	10.0	9.717		mg/L		97	90 - 110

Lab Sample ID: LCSD 490-532682/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532682

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.737		mg/L		97	90 - 110	4	20
Chloride	10.0	9.286		mg/L		93	90 - 110	4	20
Fluoride	1.00	0.9488		mg/L		95	90 - 110	4	20
Sulfate	10.0	9.360		mg/L		93	90 - 110	4	20

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-532017/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532651 — **Prep Batch: 532017**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		07/27/18 14:48	07/30/18 17:18	1
Beryllium	ND		0.00400	0.00200	mg/L		07/27/18 14:48	07/30/18 17:18	1
Magnesium	ND		1.00	0.250	mg/L		07/27/18 14:48	07/30/18 17:18	1
Vanadium	ND		0.0200	0.0100	mg/L		07/27/18 14:48	07/30/18 17:18	1

Lab Sample ID: MB 490-532017/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533240 — **Prep Batch: 532017**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Antimony	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Arsenic	ND		0.0100	0.00860	mg/L		07/27/18 14:48	08/01/18 14:08	1
Barium	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Cadmium	ND		0.00100	0.000500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Calcium	ND		1.00	0.500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Chromium	ND		0.00500	0.00300	mg/L		07/27/18 14:48	08/01/18 14:08	1
Cobalt	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Copper	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/01/18 14:08	1

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: MB 490-532017/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533240 — **Prep Batch: 532017**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Iron	ND		0.100	0.0500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Manganese	ND		0.0150	0.00500	mg/L		07/27/18 14:48	08/01/18 14:08	1
Nickel	ND		0.0100	0.00300	mg/L		07/27/18 14:48	08/01/18 14:08	1
Silver	ND		0.00500	0.00300	mg/L		07/27/18 14:48	08/01/18 14:08	1
Zinc	ND		0.0500	0.0250	mg/L		07/27/18 14:48	08/01/18 14:08	1

Lab Sample ID: MB 490-532017/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534414 — **Prep Batch: 532017**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Antimony	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Arsenic	ND		0.0100	0.00860	mg/L		07/27/18 14:48	08/07/18 09:53	1
Barium	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Beryllium	ND		0.00400	0.00200	mg/L		07/27/18 14:48	08/07/18 09:53	1
Cadmium	ND		0.00100	0.000500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Calcium	ND		1.00	0.500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Chromium	ND		0.00500	0.00300	mg/L		07/27/18 14:48	08/07/18 09:53	1
Cobalt	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Copper	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Iron	ND		0.100	0.0500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Lead	ND		0.00500	0.00200	mg/L		07/27/18 14:48	08/07/18 09:53	1
Magnesium	ND		1.00	0.250	mg/L		07/27/18 14:48	08/07/18 09:53	1
Manganese	ND		0.0150	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Nickel	ND		0.0100	0.00300	mg/L		07/27/18 14:48	08/07/18 09:53	1
Potassium	ND		1.00	0.500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Selenium	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Silver	ND		0.00500	0.00300	mg/L		07/27/18 14:48	08/07/18 09:53	1
Thallium	ND		0.0100	0.00500	mg/L		07/27/18 14:48	08/07/18 09:53	1
Vanadium	ND		0.0200	0.0100	mg/L		07/27/18 14:48	08/07/18 09:53	1
Zinc	ND		0.0500	0.0250	mg/L		07/27/18 14:48	08/07/18 09:53	1

Lab Sample ID: LCS 490-532017/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532651 — **Prep Batch: 532017**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.031		mg/L		103	85 - 115
Beryllium	0.100	0.09810		mg/L		98	85 - 115
Magnesium	10.0	9.514		mg/L		95	85 - 115
Vanadium	0.100	0.08950		mg/L		90	85 - 115

Lab Sample ID: LCS 490-532017/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533240 — **Prep Batch: 532017**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Antimony	0.100	0.1008		mg/L		101	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-532017/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533240 — **Prep Batch: 532017**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Arsenic	0.100	0.1002		mg/L		100	85 - 115
Barium	0.100	0.1060		mg/L		106	85 - 115
Cadmium	0.100	0.1006		mg/L		101	85 - 115
Calcium	10.0	9.510		mg/L		95	85 - 115
Chromium	0.100	0.1095		mg/L		110	85 - 115
Cobalt	0.100	0.1016		mg/L		102	85 - 115
Copper	0.100	0.09610		mg/L		96	85 - 115
Iron	1.00	0.9472		mg/L		95	85 - 115
Manganese	0.100	0.1069		mg/L		107	85 - 115
Nickel	0.100	0.1033		mg/L		103	85 - 115
Silver	0.100	0.1056		mg/L		106	85 - 115
Zinc	0.100	0.1027		mg/L		103	85 - 115

Lab Sample ID: LCS 490-532017/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534414 — **Prep Batch: 532017**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.082		mg/L		108	85 - 115
Antimony	0.100	0.1053		mg/L		105	85 - 115
Arsenic	0.100	0.1006		mg/L		101	85 - 115
Barium	0.100	0.1045		mg/L		105	85 - 115
Beryllium	0.100	0.1039		mg/L		104	85 - 115
Cadmium	0.100	0.1026		mg/L		103	85 - 115
Calcium	10.0	10.43		mg/L		104	85 - 115
Chromium	0.100	0.1017		mg/L		102	85 - 115
Cobalt	0.100	0.1023		mg/L		102	85 - 115
Copper	0.100	0.09930		mg/L		99	85 - 115
Iron	1.00	1.029		mg/L		103	85 - 115
Lead	0.100	0.1066		mg/L		107	85 - 115
Magnesium	10.0	10.65		mg/L		107	85 - 115
Manganese	0.100	0.1083		mg/L		108	85 - 115
Nickel	0.100	0.1019		mg/L		102	85 - 115
Potassium	10.0	10.95		mg/L		110	85 - 115
Selenium	0.100	0.1092		mg/L		109	85 - 115
Silver	0.100	0.1050		mg/L		105	85 - 115
Thallium	0.100	0.1048		mg/L		105	85 - 115
Vanadium	0.100	0.1007		mg/L		101	85 - 115
Zinc	0.100	0.1077		mg/L		108	85 - 115

Lab Sample ID: LCSD 490-532017/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532651 — **Prep Batch: 532017**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.017		mg/L		102	85 - 115	1	20
Beryllium	0.100	0.09990		mg/L		100	85 - 115	2	20
Magnesium	10.0	9.579		mg/L		96	85 - 115	1	20
Vanadium	0.100	0.09370		mg/L		94	85 - 115	5	20

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Lab Sample ID: LCSD 490-532017/3-A
Matrix: Water
Analysis Batch: 533240

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 532017

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Antimony	0.100	0.1029		mg/L		103	85 - 115	2	20
Arsenic	0.100	0.09880		mg/L		99	85 - 115	1	20
Barium	0.100	0.1072		mg/L		107	85 - 115	1	20
Cadmium	0.100	0.1014		mg/L		101	85 - 115	1	20
Calcium	10.0	9.625		mg/L		96	85 - 115	1	20
Chromium	0.100	0.1103		mg/L		110	85 - 115	1	20
Cobalt	0.100	0.1028		mg/L		103	85 - 115	1	20
Copper	0.100	0.09680		mg/L		97	85 - 115	1	20
Iron	1.00	0.9617		mg/L		96	85 - 115	2	20
Manganese	0.100	0.1093		mg/L		109	85 - 115	2	20
Nickel	0.100	0.1053		mg/L		105	85 - 115	2	20
Silver	0.100	0.1061		mg/L		106	85 - 115	0	20
Zinc	0.100	0.1094		mg/L		109	85 - 115	6	20

Lab Sample ID: LCSD 490-532017/3-A
Matrix: Water
Analysis Batch: 534414

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 532017

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.086		mg/L		109	85 - 115	0	20
Antimony	0.100	0.1080		mg/L		108	85 - 115	3	20
Arsenic	0.100	0.1021		mg/L		102	85 - 115	1	20
Barium	0.100	0.1056		mg/L		106	85 - 115	1	20
Beryllium	0.100	0.1050		mg/L		105	85 - 115	1	20
Cadmium	0.100	0.1036		mg/L		104	85 - 115	1	20
Calcium	10.0	10.46		mg/L		105	85 - 115	0	20
Chromium	0.100	0.1027		mg/L		103	85 - 115	1	20
Cobalt	0.100	0.1032		mg/L		103	85 - 115	1	20
Copper	0.100	0.1010		mg/L		101	85 - 115	2	20
Iron	1.00	1.038		mg/L		104	85 - 115	1	20
Lead	0.100	0.1065		mg/L		107	85 - 115	0	20
Magnesium	10.0	10.78		mg/L		108	85 - 115	1	20
Manganese	0.100	0.1094		mg/L		109	85 - 115	1	20
Nickel	0.100	0.1033		mg/L		103	85 - 115	1	20
Potassium	10.0	11.00		mg/L		110	85 - 115	0	20
Selenium	0.100	0.1099		mg/L		110	85 - 115	1	20
Silver	0.100	0.1052		mg/L		105	85 - 115	0	20
Thallium	0.100	0.1032		mg/L		103	85 - 115	2	20
Vanadium	0.100	0.1008		mg/L		101	85 - 115	0	20
Zinc	0.100	0.1139		mg/L		114	85 - 115	6	20

Lab Sample ID: 490-156113-A-1-B MS
Matrix: Water
Analysis Batch: 532651

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 532017

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	ND		1.00	0.9039		mg/L		90	70 - 130
Beryllium	0.0236		0.100	0.1090		mg/L		85	70 - 130
Magnesium	3.32		10.0	11.18		mg/L		79	70 - 130
Vanadium	ND		0.100	0.08160		mg/L		82	70 - 130

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: 490-156113-A-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532651 — **Prep Batch: 532017**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	ND		1.00	0.9760		mg/L		98	70 - 130	8	20
Beryllium	0.0236		0.100	0.1191		mg/L		96	70 - 130	9	20
Magnesium	3.32		10.0	12.14		mg/L		88	70 - 130	8	20
Vanadium	ND		0.100	0.09280		mg/L		93	70 - 130	13	20

Lab Sample ID: LCS 490-534638/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534988 — **Prep Batch: 534638**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Sodium	10.0	10.62		mg/L		106	85 - 115

Lab Sample ID: LCSD 490-534638/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534988 — **Prep Batch: 534638**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Sodium	10.0	11.27		mg/L		113	85 - 115	6	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-533376/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534013 — **Prep Batch: 533376**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		08/02/18 11:30	08/05/18 18:26	1

Lab Sample ID: LCS 490-533376/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534013 — **Prep Batch: 533376**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	1.970		mg/L		99	90 - 110

Lab Sample ID: LCSD 490-533376/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534013 — **Prep Batch: 533376**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.00	2.020		mg/L		101	90 - 110	3	20

Lab Sample ID: 490-156276-C-1-E MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534013 — **Prep Batch: 533376**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	ND		2.00	1.710		mg/L		86	73 - 119

Method: 365.4 - Phosphorus, Total (Continued)

Lab Sample ID: 490-156276-C-1-F MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534013 — **Prep Batch: 533376**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	ND		2.00	1.530		mg/L		77	73 - 119	11	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-532554/5 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532554

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			07/30/18 12:48	1
Alkalinity	ND		10.0	5.00	mg/L			07/30/18 12:48	1

Lab Sample ID: LCS 490-532554/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532554

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	94.55		mg/L		95	90 - 110

Lab Sample ID: LCSD 490-532554/28 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532554

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity	100	110.5		mg/L		110	90 - 110	16	20

Lab Sample ID: 490-156339-A-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532554

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	179		179.4		mg/L		0.5	20
Alkalinity	179		179.4		mg/L		0.5	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-529992/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 529992

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			07/27/18 18:29	1

Lab Sample ID: LCS 490-529992/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 529992

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Dissolved Solids	100	99.00		mg/L		99	90 - 110

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Lab Sample ID: LCSD 490-529992/3 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 529992

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Dissolved Solids			100	107.0		mg/L		107	90 - 110	8	20

Lab Sample ID: 490-156036-C-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 529992

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	8280			9290		mg/L				11	20

Lab Sample ID: 490-156237-A-11 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 529992

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	1310			1316		mg/L				0.6	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-156280-1 DU — **Client Sample ID: D&B 1:00**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 532093

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	7.0	HF		7.0		SU				0	20

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: MB 490-533246/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533246

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			08/01/18 15:58	1

Lab Sample ID: LCS 490-533246/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533246

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Organic Carbon			10.0	10.55		mg/L		105	90 - 110		

Lab Sample ID: LCSD 490-533246/7 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533246

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon			10.0	10.47		mg/L		105	90 - 110	1	20

Method: SM 5310B - Organic Carbon, Total (TOC) (Continued)

Lab Sample ID: 490-155976-A-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533246

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	59.9		20.0	79.50		mg/L		98	74 - 134

Lab Sample ID: 490-155976-A-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533246

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	59.9		20.0	78.52		mg/L		93	74 - 134	1	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-379088/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 378602 — **Prep Batch: 379088**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	1.251	U	52.8	52.8		79.1	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Actinium-228	16.02	U	21.1	21.2		29.1	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Bismuth-212	45.18	U	125	125		216	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Bismuth-214	-5.977	U	9.23	9.25		57.2	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Lead-210	93.56	U	118	119		173	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Lead-212	-15.71	U	14.1	14.2		31.4	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Lead-214	-4.667	U	17.2	17.2		30.6	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Potassium-40	-73.34	U	96.5	96.8		182	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Protactinium-231	-54.53	U	338	338		578	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Radium-226	64.74	U G	131	131	125	222	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Radium-228	16.02	U	21.1	21.2		29.1	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Thallium-208	1.134	U	9.65	9.65		13.5	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Thorium-232	16.02	U	21.1	21.2		29.1	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Thorium-234	35.24	U	71.0	71.1		167	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Uranium-235	2.184	U	54.3	54.3		93.2	pCi/L	07/30/18 11:40	07/30/18 18:55	1
Uranium-238	35.24	U	71.0	71.1		167	pCi/L	07/30/18 11:40	07/30/18 18:55	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*07/30/18 11:40*	*07/30/18 18:55*	*1*

Lab Sample ID: LCS 160-379088/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 378615 — **Prep Batch: 379088**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Americium-241	136000	130200		15000		523	pCi/L	96	90 - 111
Cesium-137	45500	45050		4520		167	pCi/L	99	90 - 111
Cobalt-60	32900	32190		3190		84.7	pCi/L	98	89 - 110

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: 180-80153-D-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 378603 — **Prep Batch: 379088**

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Actinium-227	-3.95	U		30.70	U	47.8		87.1	pCi/L			0.24	1
Actinium-228	14.5	U		6.287	U	28.4		42.5	pCi/L			0.11	1
Bismuth-212	-67.3	U		-65.25	U	126		213	pCi/L			0.01	1
Bismuth-214	99.8			103.2		26.7		22.6	pCi/L			0.07	1
Lead-210	-71.2	U		125.9	U	167		220	pCi/L			0.56	1
Lead-212	-1.56	U		5.620	U	11.6		19.0	pCi/L			0.23	1
Lead-214	93.2			92.53		21.4		21.8	pCi/L			0.01	1
Potassium-40	5.85	U		-41.36	U	184		235	pCi/L			0.12	1
Protactinium-231	79.3	U		0.0000	U	89.9		728	pCi/L			0.21	1
Radium-226	-159	U G		386.0	G F	169	125	173	pCi/L			1.11	1
Radium-228	14.5	U		6.287	U	28.4		42.5	pCi/L			0.11	1
Thallium-208	2.45	U		4.654	U	9.45		12.8	pCi/L			0.12	1
Thorium-232	14.5	U		6.287	U	28.4		42.5	pCi/L			0.11	1
Thorium-234	65.2	U		-166.0	U	180		276	pCi/L			0.64	1
Uranium-235	-28.7	U		12.39	U	59.5		108	pCi/L			0.30	1
Uranium-238	65.2	U		-166.0	U	180		276	pCi/L			0.64	1

Other Detected Radionuclides	*Sample Result*	*Sample Qual*		*DU Result*	*DU Qual*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*			*RER*	*RER Limit*
Other Detected Radionuclide	*None*			*None*					*pCi/L*				

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-381190/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.9739		0.586	0.596	3.00	0.780	pCi/L	08/08/18 17:38	08/10/18 08:12	1
Gross Beta	0.08253	U	0.530	0.530	4.00	0.912	pCi/L	08/08/18 17:38	08/10/18 08:12	1

Lab Sample ID: LCS 160-381190/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha			51.0	38.76		5.76	3.00	1.36	pCi/L	76	73 - 133		

Lab Sample ID: LCSB 160-381190/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte			Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta			88.0	84.66		8.99	4.00	0.939	pCi/L	96	75 - 125		

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Lab Sample ID: 180-79813-H-1-B MS
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha	88.1	G	637	545.3		85.5	3.00	22.5	pCi/L	72	60 - 140		

Lab Sample ID: 180-79813-H-1-C MSBT
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta	28.5	G	1100	1116	G	118	4.00	13.0	pCi/L	99	60 - 140		

Lab Sample ID: 180-79813-H-1-D DU
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Gross Alpha	88.1	G		64.27	G	23.8	3.00	24.4	pCi/L			0.47	1
Gross Beta	28.5	G		31.93	G	10.4	4.00	12.2	pCi/L			0.16	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

GC/MS VOA

Analysis Batch: 531609

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	8260B	
MB 490-531609/6	Method Blank	Total/NA	Water	8260B	
LCS 490-531609/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-531609/4	Lab Control Sample Dup	Total/NA	Water	8260B	
490-156315-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-156315-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

Analysis Batch: 534615

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-2	Trip Blank	Total/NA	Water	8260B	
MB 490-534615/6	Method Blank	Total/NA	Water	8260B	
LCS 490-534615/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-534615/4	Lab Control Sample Dup	Total/NA	Water	8260B	
490-157045-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-157045-B-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 532387

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	OK GRO	
MB 490-532387/5	Method Blank	Total/NA	Water	OK GRO	
LCS 490-532387/4	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-532387/24	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 532991

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	3510C	
MB 490-532991/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-532991/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-532991/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 533735

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	OK DRO	532991
MB 490-532991/1-A	Method Blank	Total/NA	Water	OK DRO	532991
LCS 490-532991/2-A	Lab Control Sample	Total/NA	Water	OK DRO	532991
LCSD 490-532991/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	532991

HPLC/IC

Analysis Batch: 531837

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	300.0	
490-156280-1	D&B 1:00	Total/NA	Water	300.0	
MB 490-531837/3	Method Blank	Total/NA	Water	300.0	
LCS 490-531837/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-531837/5	Lab Control Sample Dup	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 531837 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156277-E-23 MS	Matrix Spike	Total/NA	Water	300.0	

Analysis Batch: 531838

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	300.0	
MB 490-531838/3	Method Blank	Total/NA	Water	300.0	
LCS 490-531838/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-531838/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-156277-E-23 MS	Matrix Spike	Total/NA	Water	300.0	

Analysis Batch: 532682

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	300.0	
MB 490-532682/3	Method Blank	Total/NA	Water	300.0	
LCS 490-532682/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-532682/5	Lab Control Sample Dup	Total/NA	Water	300.0	

Metals

Prep Batch: 532017

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7	
MB 490-532017/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-532017/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-532017/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	
490-156113-A-1-B MS	Matrix Spike	Total/NA	Water	200.7	
490-156113-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	

Analysis Batch: 532651

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7 Rev 4.4	532017
MB 490-532017/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	532017
LCS 490-532017/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	532017
LCSD 490-532017/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	532017
490-156113-A-1-B MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	532017
490-156113-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	532017

Analysis Batch: 533240

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7 Rev 4.4	532017
MB 490-532017/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	532017
LCS 490-532017/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	532017
LCSD 490-532017/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	532017

Analysis Batch: 534414

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7 Rev 4.4	532017
MB 490-532017/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	532017
LCS 490-532017/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	532017
LCSD 490-532017/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	532017

Metals (Continued)

Analysis Batch: 534451

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7 Rev 4.4	532017

Analysis Batch: 534519

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	SM 2340B	

Prep Batch: 534638

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7	
LCS 490-534638/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-534638/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	

Analysis Batch: 534988

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	200.7 Rev 4.4	534638
LCS 490-534638/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	534638
LCSD 490-534638/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	534638

General Chemistry

Analysis Batch: 529992

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	SM 2540C	
MB 490-529992/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-529992/2	Lab Control Sample	Total/NA	Water	SM 2540C	
LCSD 490-529992/3	Lab Control Sample Dup	Total/NA	Water	SM 2540C	
490-156036-C-1 DU	Duplicate	Total/NA	Water	SM 2540C	
490-156237-A-11 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 532093

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	SM 4500 H+ B	
LCS 490-532093/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-156280-1 DU	D&B 1:00	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 532554

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	SM 2320B	
MB 490-532554/5	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-532554/6	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-532554/28	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-156339-A-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Analysis Batch: 533246

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	SM 5310B	
MB 490-533246/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-533246/6	Lab Control Sample	Total/NA	Water	SM 5310B	
LCSD 490-533246/7	Lab Control Sample Dup	Total/NA	Water	SM 5310B	
490-155976-A-1 MS	Matrix Spike	Total/NA	Water	SM 5310B	

General Chemistry (Continued)

Analysis Batch: 533246 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-155976-A-1 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

Prep Batch: 533376

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	365.2/365.3/365	
MB 490-533376/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-533376/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-533376/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-156276-C-1-E MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-156276-C-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 534013

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	365.4	533376
MB 490-533376/1-A	Method Blank	Total/NA	Water	365.4	533376
LCS 490-533376/2-A	Lab Control Sample	Total/NA	Water	365.4	533376
LCSD 490-533376/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	533376
490-156276-C-1-E MS	Matrix Spike	Total/NA	Water	365.4	533376
490-156276-C-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	533376

Rad

Prep Batch: 379088

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	Fill_Geo-0	
MB 160-379088/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-379088/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
180-80153-D-1-B DU	Duplicate	Total/NA	Water	Fill_Geo-0	

Prep Batch: 381190

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156280-1	D&B 1:00	Total/NA	Water	Evaporation	
MB 160-381190/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-381190/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-381190/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
180-79813-H-1-B MS	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-C MSBT	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-D DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: D&B 1:00

Lab Sample ID: 490-156280-1
Date Collected: 07/25/18 12:58
Matrix: Water
Date Received: 07/26/18 09:45

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		50	10 mL	10 mL	531609	07/26/18 15:27	RP	TAL NSH
Total/NA	Analysis	OK GRO		10	5 mL	5 mL	532387	07/30/18 18:50	S1S	TAL NSH
Total/NA	Prep	3510C			1079.1 mL	1 mL	532991	08/01/18 10:49	KWS	TAL NSH
Total/NA	Analysis	OK DRO		20			533735	08/04/18 09:31	PRB	TAL NSH
Total/NA	Analysis	300.0		20			531837	07/26/18 19:42	SW1	TAL NSH
Total/NA	Analysis	300.0		50			531837	07/26/18 20:00	SW1	TAL NSH
Total/NA	Analysis	300.0		50			531838	07/26/18 20:00	SW1	TAL NSH
Total/NA	Analysis	300.0		5000			532682	07/31/18 18:37	JHS	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	534638	08/08/18 11:20	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		100			534988	08/09/18 10:48	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	532017	07/27/18 14:48	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			532651	07/30/18 18:20	CML	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	532017	07/27/18 14:48	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		5			533240	08/01/18 14:51	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	532017	07/27/18 14:48	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			534414	08/07/18 10:24	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	532017	07/27/18 14:48	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		50			534451	08/07/18 15:17	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			534519	08/07/18 23:26	BLG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	533376	08/02/18 11:30	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	534013	08/05/18 18:43	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	532554	07/30/18 13:36	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	529992	07/27/18 18:29	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			532093	07/27/18 18:39	JDG	TAL NSH
Total/NA	Analysis	SM 5310B		2	50 mL	50 mL	533246	08/01/18 15:58	CLJ	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	379088	07/30/18 11:40	EAW	TAL SL
Total/NA	Analysis	901.1		1			378602	07/30/18 21:08	KLS	TAL SL
Total/NA	Prep	Evaporation			0.6 mL	1.0 g	381190	08/08/18 17:38	MRB	TAL SL
Total/NA	Analysis	9310		1			381569	08/10/18 08:14	RTM	TAL SL

Client Sample ID: Trip Blank

Lab Sample ID: 490-156280-2
Date Collected: 07/25/18 00:01
Matrix: Water
Date Received: 07/26/18 09:45

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	10 mL	10 mL	534615	08/08/18 17:15	SW1	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Laboratory: TestAmerica Nashville

Unless otherwise noted, all analytes for this laboratory were covered under each accreditation/certification below.

Authority	Program	EPA Region	Identification Number	Expiration Date
Oklahoma	State Program	6	9412	08-31-18

The following analytes are included in this report, but accreditation/certification is not offered by the governing authority:

Analysis Method	Prep Method	Matrix	Analyte
SM 2320B		Water	Bicarbonate Alkalinity as CaCO3

Texas	NELAP	6	T104704077	08-31-19

The following analytes are included in this report, but are not accredited/certified under this accreditation/certification:

Analysis Method	Prep Method	Matrix	Analyte
200.7 Rev 4.4	200.7	Water	Antimony
200.7 Rev 4.4	200.7	Water	Arsenic
200.7 Rev 4.4	200.7	Water	Cobalt
200.7 Rev 4.4	200.7	Water	Lead
200.7 Rev 4.4	200.7	Water	Potassium
200.7 Rev 4.4	200.7	Water	Selenium
200.7 Rev 4.4	200.7	Water	Thallium
200.7 Rev 4.4	200.7	Water	Vanadium
300.0		Water	Bromide

The following analytes are included in this report, but accreditation/certification is not offered by the governing authority:

Analysis Method	Prep Method	Matrix	Analyte
OK DRO	3510C	Water	C10-C28
OK GRO		Water	C6-C10 OK
SM 2320B		Water	Bicarbonate Alkalinity as CaCO3

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-18 *
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-18 *
Nevada	State Program	9	MO000542018-1	07-31-18 *
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-18 *
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-18 *
West Virginia DEP	State Program	3	381	08-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-156280 Chain of Custody

Cooler Received/Opened On 07-26-2018 @ 09:45

Time Samples Removed From Cooler 12:19 Time Samples Placed In Storage 12:26 (2 Hour Window)

1. Tracking # 8125 (last 4 digits, FedEx) Courier: FedEx

IR Gun ID 14740456 pH Strip Lot HC740840 Chlorine Strip Lot 1114172

2. Temperature of rep. sample or temp blank when opened: 1.3 Degrees Celsius
3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO NA
4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 (front)
5. Were the seals intact, signed, and dated correctly? YES...NO...NA
6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) KP

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA
8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None
9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None
10. Did all containers arrive in good condition (unbroken)? YES...NO...NA
11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA
12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #

I certify that I unloaded the cooler and answered questions 7-14 (intial) JJ

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA
16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) JJ

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA
18. Did you sign the custody papers in the appropriate place? YES...NO...NA
19. Were correct containers used for the analysis requested? YES...NO...NA
20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) JJ

I certify that I attached a label with the unique LIMS number to each container (intial) JJ

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#

Revised 8/23/17

BIS = Broken in shipment
Cooler Receipt Form.doc

LF-1
End of Form

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

Loc: 490
156280

TestAmerica — LEADER IN ENVIRONMENTAL TESTING

Client Information	Sampler: Jarrod Maly	Lab PM: Gambill, Jennifer	Carrier Tracking No:
Client Contact: Dr. James Rosenblum	Phone: 580 541 0319	E-Mail: jennifer.gambill@testamericainc.com	Page of
Company: CH2M Hill, Inc.			Job #:
Address: 12377 Merit Drive Suite 1000	Due Date Requested:		
City: Dallas	TAT Requested (days):		
State, Zip: TX, 75251			
Phone: 248-939-3216(Tel)	PO #:		
Email: james.rosenblum@ch2m.com	WO #:		
Project Name: OWRB Study Phase II	Project #: 49013620		
Site:	SSOW#:		

Analysis Requested

Preservation Codes:
A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA, M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)
Other:

Sample Name: D+B 1:00

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	7-25-18	12:58	G	W																	
Gross Alpha/Beta (1)			G	W																	
Alk/TC/pH (3)			G	W																	
Metals/Hardness (1)			G	W																	
TOC (1)			G	W																	
BTEX/GRO (6)			G	W																	
TDS (1)			G	W																	
DRO (2)			G	W																	
phosphorus (1)			G	W																	
			G	W																	

Possible Hazard Identification: ☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month): ☐ Return To Client ☐ Disposal By Lab ☐ Archive For _____ Months

Deliverable Requested: I, II, III, IV, Other (specify) Owen Mills

Special Instructions/QC Requirements:

Empty Kit Relinquished by: ~~Jacob Hernandez~~ OWRB Date: 7-25-18 Time: Method of Shipment: Hand delivered

Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company
			Fed Ex		
Relinquished by:	Date/Time:	Company	Received by: [illegible]	Date/Time: 07/26/18 09:45	Company TA-NAS
Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 1.3

Ver: 08/04/2016

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-156280 Chain of Custody

Cooler Received/Opened On____07-26-2018_@___09:45_____

Time Samples Removed From Cooler 12:19 Time Samples Placed In Storage 12:26 (2 Hour Window)

1. Tracking # 8125 (last 4 digits, FedEx) Courier: _FedEx_

IR Gun ID__14740456_____ pH Strip Lot HC740840 Chlorine Strip Lot 1114178

2. Temperature of rep. sample or temp blank when opened: 1.3 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

If yes, how many and where: 1 (front)

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) KP

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #_____

I certify that I unloaded the cooler and answered questions 7-14 (intial) JJ

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) JJ

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) JJ

I certify that I attached a label with the unique LIMS number to each container (intial) JJ

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

Loc: 490
156280

TestAmerica — THE LEADER IN ENVIRONMENTAL TESTING

Client Information	Sampler: Jarrod Maly	Lab PM: Gambill, Jennifer	Carrier Tracking No:
Client Contact: Dr. James Rosenblum	Phone: 580 541 0319	E-Mail: jennifer.gambill@testamericainc.com	Page of
Company: CH2M Hill, Inc.			Job #:
Address: 12377 Merit Drive Suite 1000	Due Date Requested:		
City: Dallas	TAT Requested (days):		
State, Zip: TX, 75251			
Phone: 248-939-3216(Tel)	PO #:		
Email: james.rosenblum@ch2m.com	WO #:		
Project Name: OWRB Study Phase II	Project #: 49013620		
Site:	SSOW#:		

Analysis Requested

Preservation Codes:
A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA
M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)
Other:

Sample Name: D+B 1:00

Sample Identification	Sample Date	Sample Time	Sample Type (C=Comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	7-25-18	12:58	G	W																	
Gross Alpha/Beta (1)			G	W																	
Alk/IC/pH (3)			G	W																	
Metals/Hardness (1)			G	W																	
TOC (1)			G	W																	
BTEX/GRO (6)			G	W																	
TDS (1)			G	W																	
DRO (2)			G	W																	
phosphorus (1)			G	W																	
			G	W																	

Possible Hazard Identification: ☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month): ☐ Return To Client ☐ Disposal By Lab ☐ Archive For _____ Months

Deliverable Requested: I, II, III, IV, Other (specify) Owen Milks

Special Instructions/QC Requirements:

Empty Kit Relinquished by: ~~Jacob Hernandez~~ OWRB Date: 7-25-18 Time: Method of Shipment: Hand delivered

Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company
			Fed Ex		
Relinquished by:	Date/Time:	Company	Received by: [illegible]	Date/Time: 07/26/18 09:45	Company TA-NAS
Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 1.3

Ver: 08/04/2016

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8/14/2018

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: D&B 1:00

Date Collected: 07/25/18 12:58
Date Received: 07/26/18 09:45

Lab Sample ID: 490-156280-1

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	1730		50.0	10.0	ug/L			07/26/18 15:27	50
Ethylbenzene	217		50.0	9.50	ug/L			07/26/18 15:27	50
Toluene	1950		50.0	8.50	ug/L			07/26/18 15:27	50
Xylenes, Total	839		150	29.0	ug/L			07/26/18 15:27	50

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*99*		*70 - 130*		*07/26/18 15:27*	*50*
4-Bromofluorobenzene (Surr)	*102*		*70 - 130*		*07/26/18 15:27*	*50*
Dibromofluoromethane (Surr)	*93*		*70 - 130*		*07/26/18 15:27*	*50*
Toluene-d8 (Surr)	*100*		*70 - 130*		*07/26/18 15:27*	*50*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	7050		200	100	ug/L			07/30/18 18:50	10

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*83*		*70 - 130*		*07/30/18 18:50*	*10*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	8630		1850	927	ug/L		08/01/18 10:49	08/04/18 09:31	20

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*0*	*X*	*50 - 150*	*08/01/18 10:49*	*08/04/18 09:31*	*20*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	372		50.0	2.50	mg/L			07/26/18 20:00	50
Nitrate as N	ND		5.00	2.50	mg/L			07/26/18 20:00	50
Chloride	63400		5000	3500	mg/L			07/31/18 18:37	5000
Nitrite as N	ND		5.00	2.50	mg/L			07/26/18 20:00	50
Fluoride	3.07		2.00	1.20	mg/L			07/26/18 19:42	20
Sulfate	705		50.0	30.0	mg/L			07/26/18 20:00	50

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	11700		10.0	5.00	mg/L			08/07/18 23:26	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	0.716		0.100	0.0500	mg/L		08/02/18 11:30	08/05/18 18:43	1
Bicarbonate Alkalinity as CaCO3	114		10.0	5.00	mg/L			07/30/18 13:36	1
Alkalinity	114		10.0	5.00	mg/L			07/30/18 13:36	1
Total Dissolved Solids	113000		1000	700	mg/L			07/27/18 18:29	1
pH	7.0	HF	0.1	0.1	SU			07/27/18 18:39	1
Total Organic Carbon	54.4		2.00	1.00	mg/L			08/01/18 15:58	2

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156280-1
SDG: D&B

Client Sample ID: Trip Blank

Lab Sample ID: 490-156280-2

Date Collected: 07/25/18 00:01
Matrix: Water
Date Received: 07/26/18 09:45

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/08/18 17:15	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/08/18 17:15	1
Toluene	ND		1.00	0.170	ug/L			08/08/18 17:15	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/08/18 17:15	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*115*		*70 - 130*		*08/08/18 17:15*	*1*
4-Bromofluorobenzene (Surr)	*100*		*70 - 130*		*08/08/18 17:15*	*1*
Dibromofluoromethane (Surr)	*108*		*70 - 130*		*08/08/18 17:15*	*1*
Toluene-d8 (Surr)	*96*		*70 - 130*		*08/08/18 17:15*	*1*

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-156673-1
TestAmerica Sample Delivery Group: Woods Co. Miss Lime
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Dr. James Rosenblum

Jennifer Gambill

Authorized for release by:
8/24/2018 9:23:33 AM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

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This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-156673-1	Woods Co. Miss Lime	Water	07/31/18 09:00	08/01/18 10:00
490-156673-2	Trip Blank	Water	07/31/18 00:01	08/01/18 10:00

Job ID: 490-156673-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-156673-1

Comments
No additional comments.

Receipt
The samples were received on 8/1/2018 10:00 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 0.6º C.

HPLC/IC
Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Woods Co. Miss Lime (490-156673-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: Due to the sample matrix, the matrix spike (MS) for analytical batch 490-533129 could not be evaluated for accuracy and precision for nitrite. The associated laboratory control sample (LCS) met acceptance criteria.

Method(s) 300.0: Reanalysis of the following sample was performed outside of the analytical holding time due to the sample matrix : Woods Co. Miss Lime (490-156673-1).

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC VOA
Method(s) OK GRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate/sample duplicate (MS/MSD/DUP) associated with analytical batch 490-533562.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-533551 and analytical batch 490-533965.

Method(s) OK DRO: The following sample was diluted due to abundance of target analytes: Woods Co. Miss Lime (490-156673-1). As such, surrogate recoveries are below the calibration range or are not reported, and elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Metals
Method(s) 200.7 Rev 4.4: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for preparation batch 490-533242 and analytical batch 490-533579 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits. (490-155787-A-5-C MS) and (490-155787-A-5-D MSD)

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

General Chemistry
Method(s) SM 2540C: The analysis volume selected for the following sample produced a base result greater than 200mg before calculation of the final result: Woods Co. Miss Lime (490-156673-1). The reference method specifies that no more than 200mg of weight be recovered for a chosen sample analysis volume in order to produce the best data precision. As such, these data have been qualified.

Method(s) 365.2/365.3/365: The following sample was diluted due to the nature of the sample matrix: Woods Co. Miss Lime (490-156673-1). Elevated reporting limits (RLs) are provided.

Method(s) SM 5310B: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-535562 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Job ID: 490-156673-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD

Method(s) 901.1: Gamma Prep Batch 160-379989: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Woods Co. Miss Lime (490-156673-1), (LCS 160-379989/2-A), (MB 160-379989/1-A), (490-156682-O-1-A) and (490-156682-O-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-379989: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative. Woods Co. Miss Lime (490-156673-1), (MB 160-379989/1-A), (490-156682-O-1-A) and (490-156682-O-1-B DU).

Method(s) 9310: Gross Alpha/Beta Prep Batch 160-381190: The gross alpha and beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Woods Co. Miss Lime (490-156673-1), (180-79813-H-1-A) and (180-79813-H-1-D DU). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Qualifiers

GC/MS VOA

Qualifier	Qualifier Description
F1	MS and/or MSD Recovery is outside acceptance limits.

GC Semi VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

HPLC/IC

Qualifier	Qualifier Description
F1	MS and/or MSD Recovery is outside acceptance limits.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.
H	Sample was prepped or analyzed beyond the specified holding time

Metals

Qualifier	Qualifier Description
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.
F1	MS and/or MSD Recovery is outside acceptance limits.
B	Compound was found in the blank and sample.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

General Chemistry

Qualifier	Qualifier Description
E	Result exceeded calibration range.
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.
F1	MS and/or MSD Recovery is outside acceptance limits.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control

Glossary (Continued)

Abbreviation	These commonly used abbreviations may or may not be present in this report.
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Client Sample ID: Woods Co. Miss Lime

Lab Sample ID: 490-156673-1

Date Collected: 07/31/18 09:00
Date Received: 08/01/18 10:00

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	444		5.00	1.00	ug/L			08/01/18 18:22	5
Ethylbenzene	138		5.00	0.950	ug/L			08/01/18 18:22	5
Toluene	685		5.00	0.850	ug/L			08/01/18 18:22	5
Xylenes, Total	818		15.0	2.90	ug/L			08/01/18 18:22	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*108*		*70 - 130*		*08/01/18 18:22*	*5*
4-Bromofluorobenzene (Surr)	*115*		*70 - 130*		*08/01/18 18:22*	*5*
Dibromofluoromethane (Surr)	*95*		*70 - 130*		*08/01/18 18:22*	*5*
Toluene-d8 (Surr)	*94*		*70 - 130*		*08/01/18 18:22*	*5*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	856		20.0	10.0	ug/L			08/03/18 12:53	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*90*		*70 - 130*		*08/03/18 12:53*	*1*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	59100		4750	2370	ug/L		08/03/18 06:18	08/05/18 20:56	50

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*0*	*X*	*50 - 150*	*08/03/18 06:18*	*08/05/18 20:56*	*50*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	1710		500	25.0	mg/L			08/06/18 23:16	500
Nitrate as N	ND	H	1000	500	mg/L			08/02/18 18:15	10000
Chloride	136000		10000	7000	mg/L			08/02/18 18:15	10000
Nitrite as N	ND	H	1000	500	mg/L			08/02/18 18:15	10000
Fluoride	3.64	J	5.00	3.00	mg/L			08/01/18 21:30	50
Sulfate	530		50.0	30.0	mg/L			08/01/18 21:30	50

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	3.13	B	0.500	0.250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Antimony	ND		10.0	5.00	mg/L		08/02/18 07:52	08/06/18 15:25	1000
Arsenic	ND		0.0500	0.0430	mg/L		08/02/18 07:52	08/03/18 18:10	5
Barium	1.56		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Beryllium	ND		0.0200	0.0100	mg/L		08/02/18 07:52	08/03/18 18:10	5
Cadmium	ND		0.00500	0.00250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Calcium	11900		100	50.0	mg/L		08/02/18 07:52	08/04/18 17:29	100
Chromium	0.0180	J	0.0250	0.0150	mg/L		08/02/18 07:52	08/03/18 18:10	5
Cobalt	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Copper	0.0540		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Iron	146		0.500	0.250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Lead	0.104		0.0250	0.0100	mg/L		08/02/18 07:52	08/03/18 18:10	5
Magnesium	2240		100	25.0	mg/L		08/02/18 07:52	08/04/18 17:29	100
Manganese	0.403		0.0750	0.0250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Nickel	0.0360	J	0.0500	0.0150	mg/L		08/02/18 07:52	08/03/18 18:10	5

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Client Sample ID: Woods Co. Miss Lime

Lab Sample ID: 490-156673-1

Date Collected: 07/31/18 09:00
Matrix: Water
Date Received: 08/01/18 10:00

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Potassium	**559**		5.00	2.50	mg/L		08/02/18 07:52	08/03/18 18:10	5
Selenium	ND		10.0	5.00	mg/L		08/02/18 07:52	08/06/18 15:25	1000
Silver	**0.0460**		0.0250	0.0150	mg/L		08/02/18 07:52	08/03/18 18:10	5
Sodium	**21500**		200	80.0	mg/L		08/09/18 07:37	08/11/18 00:21	200
Thallium	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:10	5
Vanadium	ND		2.00	1.00	mg/L		08/02/18 07:52	08/04/18 17:29	100
Zinc	**3.11**		0.250	0.125	mg/L		08/02/18 07:52	08/03/18 18:10	5

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**38800**		10.0	5.00	mg/L			08/14/18 16:05	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	**1.98**		0.500	0.250	mg/L		08/08/18 09:56	08/08/18 21:10	1
Bicarbonate Alkalinity as CaCO3	**108**		10.0	5.00	mg/L			08/03/18 21:32	1
Alkalinity	**108**		10.0	5.00	mg/L			08/03/18 21:32	1
Total Dissolved Solids	**212000**	**E**	1000	700	mg/L			08/02/18 16:00	1
pH	**6.8**	**HF**	0.1	0.1	SU			08/02/18 17:11	1
Total Organic Carbon	**28.4**		1.00	0.500	mg/L			08/09/18 08:59	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	44.3	U	97.3	97.6		138	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Actinium-228	**197**		34.2	39.3		36.1	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Bismuth-212	80.2	U	144	144		242	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Bismuth-214	**377**		39.6	54.7		24.4	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Lead-210	87.4	U	155	156		237	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Lead-212	**35.7**		16.3	17.0		24.2	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Lead-214	**420**		36.2	56.6		27.4	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Potassium-40	**476**		147	155		158	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Protactinium-231	0.000	U	190	190		1070	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Radium-226	**648**	**G**	259	281	125	395	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Radium-228	**197**		34.2	39.3		36.1	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Thallium-208	1.65	U	13.0	13.0		17.1	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Thorium-232	**197**		34.2	39.3		36.1	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Thorium-234	11.5	U	176	176		297	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Uranium-235	24.3	U	56.9	56.9		77.4	pCi/L	08/02/18 16:27	08/04/18 22:19	1
Uranium-238	11.5	U	176	176		297	pCi/L	08/02/18 16:27	08/04/18 22:19	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*08/02/18 16:27*	*08/04/18 22:19*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Client Sample ID: Woods Co. Miss Lime

Lab Sample ID: 490-156673-1

Date Collected: 07/31/18 09:00
Matrix: Water
Date Received: 08/01/18 10:00

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	317	U G	828	828	3.00	1520	pCi/L	08/08/18 17:38	08/10/18 08:14	1
Gross Beta	121	U G	533	534	4.00	931	pCi/L	08/08/18 17:38	08/10/18 08:14	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Client Sample ID: Trip Blank

Lab Sample ID: 490-156673-2

Date Collected: 07/31/18 00:01
Date Received: 08/01/18 10:00

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/01/18 17:28	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/01/18 17:28	1
Toluene	ND		1.00	0.170	ug/L			08/01/18 17:28	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/01/18 17:28	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*104*		*70 - 130*		*08/01/18 17:28*	*1*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*		*08/01/18 17:28*	*1*
Dibromofluoromethane (Surr)	*96*		*70 - 130*		*08/01/18 17:28*	*1*
Toluene-d8 (Surr)	*94*		*70 - 130*		*08/01/18 17:28*	*1*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-533015/6
Matrix: Water
Analysis Batch: 533015

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/01/18 14:29	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/01/18 14:29	1
Toluene	ND		1.00	0.170	ug/L			08/01/18 14:29	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/01/18 14:29	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*106*		*70 - 130*		*08/01/18 14:29*	*1*
4-Bromofluorobenzene (Surr)	*115*		*70 - 130*		*08/01/18 14:29*	*1*
Dibromofluoromethane (Surr)	*96*		*70 - 130*		*08/01/18 14:29*	*1*
Toluene-d8 (Surr)	*97*		*70 - 130*		*08/01/18 14:29*	*1*

Lab Sample ID: LCS 490-533015/3
Matrix: Water
Analysis Batch: 533015

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	21.51		ug/L		108	70 - 130
Ethylbenzene	20.0	22.32		ug/L		112	70 - 130
Toluene	20.0	20.25		ug/L		101	70 - 130
Xylenes, Total	40.0	45.26		ug/L		113	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*112*		*70 - 130*
4-Bromofluorobenzene (Surr)	*111*		*70 - 130*
Dibromofluoromethane (Surr)	*98*		*70 - 130*
Toluene-d8 (Surr)	*95*		*70 - 130*

Lab Sample ID: 490-156605-B-3 MS
Matrix: Water
Analysis Batch: 533015

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	1780		1000	2991		ug/L		121	55 - 147
Ethylbenzene	1420		1000	2724		ug/L		130	65 - 139
Toluene	696		1000	1774		ug/L		108	64 - 136
Xylenes, Total	4110	F1	2000	6808	F1	ug/L		135	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*109*		*70 - 130*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*
Dibromofluoromethane (Surr)	*94*		*70 - 130*
Toluene-d8 (Surr)	*95*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-156605-B-3 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533015

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	1780		1000	3020		ug/L		124	55 - 147	1	22
Ethylbenzene	1420		1000	2796		ug/L		137	65 - 139	3	18
Toluene	696		1000	1832		ug/L		114	64 - 136	3	18
Xylenes, Total	4110	F1	2000	7019	F1	ug/L		145	69 - 132	3	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*110*		*70 - 130*
4-Bromofluorobenzene (Surr)	*113*		*70 - 130*
Dibromofluoromethane (Surr)	*101*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-533562/6 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			08/03/18 10:36	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*99*		*70 - 130*		*08/03/18 10:36*	*1*

Lab Sample ID: LCS 490-533562/5 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
C6-C10 OK			200	183.1		ug/L		92	80 - 120		

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*100*		*70 - 130*

Lab Sample ID: LCSD 490-533562/11 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK			200	205.7		ug/L		103	80 - 120	12	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*103*		*70 - 130*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-533551/1-A
Matrix: Water
Analysis Batch: 533965

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 533551

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		08/03/18 06:18	08/05/18 10:17	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*84*		*50 - 150*	*08/03/18 06:18*	*08/05/18 10:17*	*1*

Lab Sample ID: LCS 490-533551/2-A
Matrix: Water
Analysis Batch: 533965

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533551

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	478.1		ug/L		96	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*104*		*50 - 150*

Lab Sample ID: LCSD 490-533551/3-A
Matrix: Water
Analysis Batch: 533965

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 533551

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	514.0		ug/L		103	80 - 120	7	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*112*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-533128/3
Matrix: Water
Analysis Batch: 533128

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			08/01/18 20:01	1
Chloride	ND		1.00	0.700	mg/L			08/01/18 20:01	1
Fluoride	ND		0.100	0.0600	mg/L			08/01/18 20:01	1
Sulfate	ND		1.00	0.600	mg/L			08/01/18 20:01	1

Lab Sample ID: LCS 490-533128/4
Matrix: Water
Analysis Batch: 533128

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.071		mg/L		91	90 - 110
Chloride	10.0	9.500		mg/L		95	90 - 110
Fluoride	1.00	0.9295		mg/L		93	90 - 110
Sulfate	10.0	9.306		mg/L		93	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-533128/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533128

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride	10.0	9.319		mg/L		93	90 - 110	2	20
Fluoride	1.00	0.9264		mg/L		93	90 - 110	0	20
Sulfate	10.0	9.395		mg/L		94	90 - 110	1	20

Lab Sample ID: MB 490-533458/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533458

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			08/02/18 10:48	1
Chloride	ND		1.00	0.700	mg/L			08/02/18 10:48	1
Fluoride	ND		0.100	0.0600	mg/L			08/02/18 10:48	1
Sulfate	ND		1.00	0.600	mg/L			08/02/18 10:48	1

Lab Sample ID: LCS 490-533458/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533458

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Chloride	10.0	9.464		mg/L		95	90 - 110
Fluoride	1.00	0.9258		mg/L		92	90 - 110
Sulfate	10.0	9.268		mg/L		92	90 - 110

Lab Sample ID: LCSD 490-533458/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533458

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride	10.0	9.391		mg/L		94	90 - 110	1	20
Fluoride	1.00	0.9091		mg/L		91	90 - 110	2	20
Sulfate	10.0	9.306		mg/L		93	90 - 110	0	20

Lab Sample ID: MB 490-533459/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533459

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			08/02/18 10:48	1
Nitrite as N	ND		0.100	0.0500	mg/L			08/02/18 10:48	1

Lab Sample ID: LCS 490-533459/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533459

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	1.016		mg/L		102	90 - 110
Nitrite as N	1.00	1.005		mg/L		100	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-533459/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533459

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	1.001		mg/L		100	90 - 110	1	20
Nitrite as N	1.00	0.9792		mg/L		98	90 - 110	3	20

Lab Sample ID: MB 490-534266/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534266

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			08/06/18 20:57	1
Chloride	ND		1.00	0.700	mg/L			08/06/18 20:57	1
Fluoride	ND		0.100	0.0600	mg/L			08/06/18 20:57	1
Sulfate	ND		1.00	0.600	mg/L			08/06/18 20:57	1

Lab Sample ID: LCS 490-534266/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534266

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.525		mg/L		95	90 - 110
Chloride	10.0	9.921		mg/L		99	90 - 110
Fluoride	1.00	0.9666		mg/L		97	90 - 110
Sulfate	10.0	9.736		mg/L		97	90 - 110

Lab Sample ID: LCSD 490-534266/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534266

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.559		mg/L		95	90 - 110	0	20
Chloride	10.0	10.06		mg/L		101	90 - 110	1	20
Fluoride	1.00	1.060		mg/L		106	90 - 110	9	20
Sulfate	10.0	10.42		mg/L		104	90 - 110	7	20

Lab Sample ID: 490-156590-B-16 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534266

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	0.505	J	10.0	10.27		mg/L		97	80 - 120
Chloride	3.98		10.0	14.27		mg/L		103	80 - 120
Fluoride	0.148		1.00	1.106		mg/L		96	80 - 120

Lab Sample ID: 490-156658-E-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Dissolved**
Analysis Batch: 533128

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Chloride	17.6		10.0	27.21		mg/L		96	80 - 120
Fluoride	1.05	F1	1.00	1.728	F1	mg/L		67	80 - 120

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-533242/1-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 533242

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.06190	J	0.100	0.0500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Antimony	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Arsenic	ND		0.0100	0.00860	mg/L		08/02/18 07:52	08/02/18 16:38	1
Barium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Beryllium	ND		0.00400	0.00200	mg/L		08/02/18 07:52	08/02/18 16:38	1
Cadmium	ND		0.00100	0.000500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Calcium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Chromium	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/02/18 16:38	1
Cobalt	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Copper	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Lead	ND		0.00500	0.00200	mg/L		08/02/18 07:52	08/02/18 16:38	1
Magnesium	ND		1.00	0.250	mg/L		08/02/18 07:52	08/02/18 16:38	1
Manganese	ND		0.0150	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Nickel	ND		0.0100	0.00300	mg/L		08/02/18 07:52	08/02/18 16:38	1
Selenium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Silver	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/02/18 16:38	1
Thallium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Vanadium	ND		0.0200	0.0100	mg/L		08/02/18 07:52	08/02/18 16:38	1
Zinc	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/02/18 16:38	1

Lab Sample ID: MB 490-533242/1-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 533242

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.09980	J	0.100	0.0500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Antimony	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Arsenic	ND		0.0100	0.00860	mg/L		08/02/18 07:52	08/03/18 16:56	1
Barium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Beryllium	ND		0.00400	0.00200	mg/L		08/02/18 07:52	08/03/18 16:56	1
Cadmium	ND		0.00100	0.000500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Chromium	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/03/18 16:56	1
Cobalt	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Copper	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Iron	ND		0.100	0.0500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Lead	ND		0.00500	0.00200	mg/L		08/02/18 07:52	08/03/18 16:56	1
Manganese	ND		0.0150	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Nickel	ND		0.0100	0.00300	mg/L		08/02/18 07:52	08/03/18 16:56	1
Potassium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Selenium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Silver	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/03/18 16:56	1
Thallium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Zinc	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 16:56	1

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-533242/2-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.081		mg/L		108	85 - 115
Antimony	0.100	0.1033		mg/L		103	85 - 115
Arsenic	0.100	0.1027		mg/L		103	85 - 115
Barium	0.100	0.1030		mg/L		103	85 - 115
Beryllium	0.100	0.09980		mg/L		100	85 - 115
Cadmium	0.100	0.1059		mg/L		106	85 - 115
Calcium	10.0	10.05		mg/L		101	85 - 115
Chromium	0.100	0.1079		mg/L		108	85 - 115
Cobalt	0.100	0.1057		mg/L		106	85 - 115
Copper	0.100	0.09970		mg/L		100	85 - 115
Lead	0.100	0.1074		mg/L		107	85 - 115
Magnesium	10.0	9.763		mg/L		98	85 - 115
Manganese	0.100	0.1095		mg/L		110	85 - 115
Nickel	0.100	0.1063		mg/L		106	85 - 115
Selenium	0.100	0.1108		mg/L		111	85 - 115
Silver	0.100	0.1018		mg/L		102	85 - 115
Thallium	0.100	0.1055		mg/L		106	85 - 115
Vanadium	0.100	0.09400		mg/L		94	85 - 115
Zinc	0.100	0.1077		mg/L		108	85 - 115

Lab Sample ID: LCS 490-533242/2-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.048		mg/L		105	85 - 115
Antimony	0.100	0.1037		mg/L		104	85 - 115
Arsenic	0.100	0.1049		mg/L		105	85 - 115
Barium	0.100	0.1054		mg/L		105	85 - 115
Beryllium	0.100	0.1012		mg/L		101	85 - 115
Cadmium	0.100	0.1036		mg/L		104	85 - 115
Chromium	0.100	0.1080		mg/L		108	85 - 115
Cobalt	0.100	0.1019		mg/L		102	85 - 115
Copper	0.100	0.1048		mg/L		105	85 - 115
Iron	1.00	0.9806		mg/L		98	85 - 115
Lead	0.100	0.1089		mg/L		109	85 - 115
Manganese	0.100	0.1060		mg/L		106	85 - 115
Nickel	0.100	0.1035		mg/L		104	85 - 115
Potassium	10.0	10.93		mg/L		109	85 - 115
Selenium	0.100	0.1072		mg/L		107	85 - 115
Silver	0.100	0.1002		mg/L		100	85 - 115
Thallium	0.100	0.1094		mg/L		109	85 - 115
Zinc	0.100	0.1047		mg/L		105	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCSD 490-533242/3-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.066		mg/L		107	85 - 115	1	20
Antimony	0.100	0.1036		mg/L		104	85 - 115	0	20
Arsenic	0.100	0.1026		mg/L		103	85 - 115	0	20
Barium	0.100	0.1017		mg/L		102	85 - 115	1	20
Beryllium	0.100	0.09790		mg/L		98	85 - 115	2	20
Cadmium	0.100	0.1050		mg/L		105	85 - 115	1	20
Calcium	10.0	9.948		mg/L		99	85 - 115	1	20
Chromium	0.100	0.1070		mg/L		107	85 - 115	1	20
Cobalt	0.100	0.1051		mg/L		105	85 - 115	1	20
Copper	0.100	0.1005		mg/L		101	85 - 115	1	20
Lead	0.100	0.1078		mg/L		108	85 - 115	0	20
Magnesium	10.0	9.616		mg/L		96	85 - 115	2	20
Manganese	0.100	0.1086		mg/L		109	85 - 115	1	20
Nickel	0.100	0.1062		mg/L		106	85 - 115	0	20
Selenium	0.100	0.1104		mg/L		110	85 - 115	0	20
Silver	0.100	0.1011		mg/L		101	85 - 115	1	20
Thallium	0.100	0.1083		mg/L		108	85 - 115	3	20
Vanadium	0.100	0.09310		mg/L		93	85 - 115	1	20
Zinc	0.100	0.1071		mg/L		107	85 - 115	1	20

Lab Sample ID: LCSD 490-533242/3-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.030		mg/L		103	85 - 115	2	20
Antimony	0.100	0.1028		mg/L		103	85 - 115	1	20
Arsenic	0.100	0.1013		mg/L		101	85 - 115	3	20
Barium	0.100	0.1037		mg/L		104	85 - 115	2	20
Beryllium	0.100	0.1003		mg/L		100	85 - 115	1	20
Cadmium	0.100	0.1026		mg/L		103	85 - 115	1	20
Chromium	0.100	0.1072		mg/L		107	85 - 115	1	20
Cobalt	0.100	0.1008		mg/L		101	85 - 115	1	20
Copper	0.100	0.1008		mg/L		101	85 - 115	4	20
Iron	1.00	0.9670		mg/L		97	85 - 115	1	20
Lead	0.100	0.1059		mg/L		106	85 - 115	3	20
Manganese	0.100	0.1052		mg/L		105	85 - 115	1	20
Nickel	0.100	0.1031		mg/L		103	85 - 115	0	20
Potassium	10.0	10.82		mg/L		108	85 - 115	1	20
Selenium	0.100	0.1063		mg/L		106	85 - 115	1	20
Silver	0.100	0.09980		mg/L		100	85 - 115	0	20
Thallium	0.100	0.1082		mg/L		108	85 - 115	1	20
Zinc	0.100	0.1034		mg/L		103	85 - 115	1	20

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: 490-155787-A-5-C MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533579 — **Prep Batch: 533242**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	0.389	B	1.00	1.394		mg/L		101	70 - 130
Arsenic	ND		0.100	0.1099		mg/L		110	70 - 130
Beryllium	ND		0.100	0.09460		mg/L		95	70 - 130
Cadmium	ND		0.100	0.09890		mg/L		99	70 - 130
Calcium	179		10.0	189.2	4	mg/L		103	70 - 130
Chromium	ND		0.100	0.1028		mg/L		103	70 - 130
Cobalt	ND		0.100	0.09790		mg/L		98	70 - 130
Copper	ND		0.100	0.09900		mg/L		99	70 - 130
Lead	ND		0.100	0.09880		mg/L		99	70 - 130
Manganese	0.304	F1	0.100	0.4066		mg/L		103	70 - 130
Nickel	ND		0.100	0.1004		mg/L		100	70 - 130
Silver	ND		0.100	0.09630		mg/L		96	70 - 130
Thallium	ND		0.100	0.09260		mg/L		93	70 - 130
Vanadium	ND		0.100	0.09820		mg/L		98	70 - 130
Zinc	ND		0.100	0.1037		mg/L		104	70 - 130

Lab Sample ID: 490-155787-A-5-D MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533579 — **Prep Batch: 533242**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	0.389	B	1.00	1.420		mg/L		103	70 - 130	2	20
Arsenic	ND		0.100	0.1091		mg/L		109	70 - 130	1	20
Beryllium	ND		0.100	0.09810		mg/L		98	70 - 130	4	20
Cadmium	ND		0.100	0.1020		mg/L		102	70 - 130	3	20
Calcium	179		10.0	206.0	4	mg/L		271	70 - 130	9	20
Chromium	ND		0.100	0.1068		mg/L		107	70 - 130	4	20
Cobalt	ND		0.100	0.1013		mg/L		101	70 - 130	3	20
Copper	ND		0.100	0.1010		mg/L		101	70 - 130	2	20
Lead	ND		0.100	0.1033		mg/L		103	70 - 130	4	20
Manganese	0.304	F1	0.100	0.4374	F1	mg/L		133	70 - 130	7	20
Nickel	ND		0.100	0.1040		mg/L		104	70 - 130	4	20
Silver	ND		0.100	0.1000		mg/L		100	70 - 130	4	20
Thallium	ND		0.100	0.09660		mg/L		97	70 - 130	4	20
Vanadium	ND		0.100	0.1035		mg/L		104	70 - 130	5	20
Zinc	ND		0.100	0.1070		mg/L		107	70 - 130	3	20

Lab Sample ID: MB 490-534847/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Sodium	ND		1.00	0.400	mg/L		08/09/18 07:37	08/10/18 21:21	1

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-534847/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Sodium	10.0	9.412		mg/L		94	85 - 115

Lab Sample ID: LCSD 490-534847/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Sodium	10.0	9.166		mg/L		92	85 - 115	3	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-534595/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534595**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		08/08/18 09:56	08/08/18 20:25	1

Lab Sample ID: LCS 490-534595/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534595**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	2.070		mg/L		104	90 - 110

Lab Sample ID: 490-156658-D-2-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Dissolved**
Analysis Batch: 534825 — **Prep Batch: 534595**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	ND		2.00	1.960		mg/L		98	73 - 119

Lab Sample ID: 490-156658-D-2-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Dissolved**
Analysis Batch: 534825 — **Prep Batch: 534595**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	ND		2.00	1.790		mg/L		90	73 - 119	9	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-534146/37 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			08/03/18 21:17	1
Alkalinity	ND		10.0	5.00	mg/L			08/03/18 21:17	1

Method: SM 2320B - Alkalinity (Continued)

Lab Sample ID: LCS 490-534146/38 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	96.13		mg/L		96	90 - 110

Lab Sample ID: LCSD 490-534146/46 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity	100	99.81		mg/L		100	90 - 110	4	20

Lab Sample ID: 490-156744-I-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	481		481.9		mg/L		0.2	20
Alkalinity	481		481.9		mg/L		0.2	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-533354/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			08/02/18 16:00	1

Lab Sample ID: LCS 490-533354/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Dissolved Solids	100	100.0		mg/L		100	90 - 110

Lab Sample ID: LCSD 490-533354/3 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Dissolved Solids	100	105.0		mg/L		105	90 - 110	5	20

Lab Sample ID: 490-156658-F-2 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Total Dissolved Solids	5450	E	5364	E	mg/L		2	20

Method: SM 2540C - Solids, Total Dissolved (TDS) (Continued)

Lab Sample ID: 490-156724-G-2 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	86.0			84.00		mg/L				2	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-156656-G-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533505

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	7.1			7.1		SU				0	20

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: LB 490-535562/8 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	LB Result	LB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			08/09/18 08:59	1

Lab Sample ID: MB 490-535562/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			08/09/18 08:59	1

Lab Sample ID: LCS 490-535562/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Organic Carbon			10.0	10.55		mg/L		105	90 - 110		

Lab Sample ID: LCSD 490-535562/7 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon			10.0	10.42		mg/L		104	90 - 110	1	20

Lab Sample ID: 490-157135-I-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Organic Carbon	8.75	F1	20.0	21.94	F1	mg/L		66	74 - 134		

Method: SM 5310B - Organic Carbon, Total (TOC) (Continued)

Lab Sample ID: 490-157135-I-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	8.75	F1	20.0	22.57	F1	mg/L		69	74 - 134	3	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-379989/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380608 — **Prep Batch: 379989**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	35.39	U	56.4	56.6		111	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Actinium-228	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Bismuth-212	47.28	U	111	111		194	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Bismuth-214	0.0000	U	14.3	14.3		54.6	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-210	-101.8	U	145	147		261	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-212	-18.83	U	13.1	13.4		38.1	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-214	-16.07	U	21.4	21.4		40.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Potassium-40	-81.36	U	151	151		231	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Protactinium-231	0.0000	U	116	116		753	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Radium-226	-134.5	U G	196	197	125	351	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Radium-228	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thallium-208	0.9123	U	11.3	11.3		15.6	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thorium-232	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thorium-234	-41.42	U	137	137		237	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Uranium-235	-23.09	U	63.4	63.5		116	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Uranium-238	-41.42	U	137	137		237	pCi/L	08/02/18 16:27	08/04/18 21:04	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*08/02/18 16:27*	*08/04/18 21:04*	*1*

Lab Sample ID: LCS 160-379989/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380601 — **Prep Batch: 379989**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Americium-241	136000	133600		15400		526	pCi/L	98	90 - 111
Cesium-137	45500	43580		4380		163	pCi/L	96	90 - 111
Cobalt-60	32800	31570		3130		100	pCi/L	96	89 - 110

Lab Sample ID: 490-156682-O-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380628 — **Prep Batch: 379989**

Analyte	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Actinium-227	27.8	U	-53.30	U	127		213	pCi/L	0.43	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: 490-156682-O-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380628 — **Prep Batch: 379989**

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Actinium-228	122			133.8		57.1		49.7	pCi/L			0.13	1
Bismuth-212	69.5	U		67.44	U	115		196	pCi/L			0.01	1
Bismuth-214	214			163.0		39.6		32.0	pCi/L			0.65	1
Lead-210	101	U		195.8	U	181		234	pCi/L			0.28	1
Lead-212	55.0			53.54		19.6		23.8	pCi/L			0.04	1
Lead-214	194			144.8		35.6		31.0	pCi/L			0.72	1
Potassium-40	74.9	U		-36.11	U	239		291	pCi/L			0.27	1
Protactinium-231	132	U		-215.8	U	702		1180	pCi/L			0.32	1
Radium-226	471	G		-221.4	U G	497	125	480	pCi/L			0.94	1
Radium-228	122			133.8		57.1		49.7	pCi/L			0.13	1
Thallium-208	15.8			16.48	U	14.3		23.4	pCi/L			0.03	1
Thorium-232	122			133.8		57.1		49.7	pCi/L			0.13	1
Thorium-234	40.8	U		35.69	U	291		487	pCi/L			0.01	1
Uranium-235	-22.1	U		9.942	U	37.4		228	pCi/L			0.46	1
Uranium-238	40.8	U		35.69	U	291		487	pCi/L			0.01	1

Other Detected Radionuclides	*Sample Result*	*Sample Qual*		*DU Result*	*DU Qual*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*			*RER*	*RER Limit*
Other Detected Radionuclide	*None*			*None*					*pCi/L*				

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-381190/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.9739		0.586	0.596	3.00	0.780	pCi/L	08/08/18 17:38	08/10/18 08:12	1
Gross Beta	0.08253	U	0.530	0.530	4.00	0.912	pCi/L	08/08/18 17:38	08/10/18 08:12	1

Lab Sample ID: LCS 160-381190/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha			51.0	38.76		5.76	3.00	1.36	pCi/L	76	73 - 133		

Lab Sample ID: LCSB 160-381190/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte			Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta			88.0	84.66		8.99	4.00	0.939	pCi/L	96	75 - 125		

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Method: 9310 - Gross Alpha / Beta (GFPC) (Continued)

Lab Sample ID: 180-79813-H-1-B MS
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha	88.1	G	637	545.3		85.5	3.00	22.5	pCi/L	72	60 - 140		

Lab Sample ID: 180-79813-H-1-C MSBT
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta	28.5	G	1100	1116	G	118	4.00	13.0	pCi/L	99	60 - 140		

Lab Sample ID: 180-79813-H-1-D DU
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Gross Alpha	88.1	G		64.27	G	23.8	3.00	24.4	pCi/L			0.47	1
Gross Beta	28.5	G		31.93	G	10.4	4.00	12.2	pCi/L			0.16	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

GC/MS VOA

Analysis Batch: 533015

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	8260B	
490-156673-2	Trip Blank	Total/NA	Water	8260B	
MB 490-533015/6	Method Blank	Total/NA	Water	8260B	
LCS 490-533015/3	Lab Control Sample	Total/NA	Water	8260B	
490-156605-B-3 MS	Matrix Spike	Total/NA	Water	8260B	
490-156605-B-3 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 533562

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	OK GRO	
MB 490-533562/6	Method Blank	Total/NA	Water	OK GRO	
LCS 490-533562/5	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-533562/11	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 533551

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	3510C	
MB 490-533551/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-533551/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-533551/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 533965

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	OK DRO	533551
MB 490-533551/1-A	Method Blank	Total/NA	Water	OK DRO	533551
LCS 490-533551/2-A	Lab Control Sample	Total/NA	Water	OK DRO	533551
LCSD 490-533551/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	533551

HPLC/IC

Analysis Batch: 533128

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	300.0	
MB 490-533128/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533128/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533128/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-156658-E-1 MS	Matrix Spike	Dissolved	Water	300.0	

Analysis Batch: 533458

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	300.0	
MB 490-533458/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533458/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533458/5	Lab Control Sample Dup	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 533459

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	300.0	
MB 490-533459/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533459/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533459/5	Lab Control Sample Dup	Total/NA	Water	300.0	

Analysis Batch: 534266

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	300.0	
MB 490-534266/3	Method Blank	Total/NA	Water	300.0	
LCS 490-534266/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-534266/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-156590-B-16 MS	Matrix Spike	Total/NA	Water	300.0	

Metals

Prep Batch: 533242

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	200.7	
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	
490-155787-A-5-C MS	Matrix Spike	Total/NA	Water	200.7	
490-155787-A-5-D MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	

Analysis Batch: 533579

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	533242
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	533242
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	533242
490-155787-A-5-C MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	533242
490-155787-A-5-D MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 533865

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	200.7 Rev 4.4	533242
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	533242
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	533242
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 534014

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 534267

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	200.7 Rev 4.4	533242

Prep Batch: 534847

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	200.7	

Metals (Continued)

Prep Batch: 534847 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-534847/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-534847/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-534847/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	

Analysis Batch: 535380

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	200.7 Rev 4.4	534847
MB 490-534847/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	534847
LCS 490-534847/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	534847
LCSD 490-534847/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	534847

Analysis Batch: 536005

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	SM 2340B	

General Chemistry

Analysis Batch: 533354

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	SM 2540C	
MB 490-533354/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-533354/2	Lab Control Sample	Total/NA	Water	SM 2540C	
LCSD 490-533354/3	Lab Control Sample Dup	Total/NA	Water	SM 2540C	
490-156658-F-2 DU	Duplicate	Total/NA	Water	SM 2540C	
490-156724-G-2 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 533505

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	SM 4500 H+ B	
LCS 490-533505/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-156656-G-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 534146

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	SM 2320B	
MB 490-534146/37	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-534146/38	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-534146/46	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-156744-I-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Prep Batch: 534595

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	365.2/365.3/365	
MB 490-534595/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-534595/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
490-156658-D-2-B MS	Matrix Spike	Dissolved	Water	365.2/365.3/365	
490-156658-D-2-C MSD	Matrix Spike Duplicate	Dissolved	Water	365.2/365.3/365	

General Chemistry (Continued)

Analysis Batch: 534825

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	365.4	534595
MB 490-534595/1-A	Method Blank	Total/NA	Water	365.4	534595
LCS 490-534595/2-A	Lab Control Sample	Total/NA	Water	365.4	534595
490-156658-D-2-B MS	Matrix Spike	Dissolved	Water	365.4	534595
490-156658-D-2-C MSD	Matrix Spike Duplicate	Dissolved	Water	365.4	534595

Analysis Batch: 535562

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	SM 5310B	
LB 490-535562/8	Method Blank	Total/NA	Water	SM 5310B	
MB 490-535562/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-535562/6	Lab Control Sample	Total/NA	Water	SM 5310B	
LCSD 490-535562/7	Lab Control Sample Dup	Total/NA	Water	SM 5310B	
490-157135-I-1 MS	Matrix Spike	Total/NA	Water	SM 5310B	
490-157135-I-1 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

Rad

Prep Batch: 379989

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	Fill_Geo-0	
MB 160-379989/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-379989/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
490-156682-O-1-B DU	Duplicate	Total/NA	Water	Fill_Geo-0	

Prep Batch: 381190

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156673-1	Woods Co. Miss Lime	Total/NA	Water	Evaporation	
MB 160-381190/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-381190/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-381190/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
180-79813-H-1-B MS	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-C MSBT	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-D DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Client Sample ID: Woods Co. Miss Lime

Lab Sample ID: 490-156673-1
Date Collected: 07/31/18 09:00
Matrix: Water
Date Received: 08/01/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		5	5 mL	5 mL	533015	08/01/18 18:22	RP	TAL NSH
Total/NA	Analysis	OK GRO		1	5 mL	5 mL	533562	08/03/18 12:53	S1S	TAL NSH
Total/NA	Prep	3510C			1053 mL	1 mL	533551	08/03/18 06:18	CC	TAL NSH
Total/NA	Analysis	OK DRO		50			533965	08/05/18 20:56	PRB	TAL NSH
Total/NA	Analysis	300.0		50			533128	08/01/18 21:30	JHS	TAL NSH
Total/NA	Analysis	300.0		10000			533458	08/02/18 18:15	JHS	TAL NSH
Total/NA	Analysis	300.0		10000			533459	08/02/18 18:15	JHS	TAL NSH
Total/NA	Analysis	300.0		500			534266	08/06/18 23:16	JHS	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	534847	08/09/18 07:37	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		200			535380	08/11/18 00:21	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		5			533865	08/03/18 18:10	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		100			534014	08/04/18 17:29	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1000			534267	08/06/18 15:25	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			536005	08/14/18 16:05	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			4 mL	20 mL	534595	08/08/18 09:56	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	534825	08/08/18 21:10	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	534146	08/03/18 21:32	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	533354	08/02/18 16:00	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			533505	08/02/18 17:11	JDG	TAL NSH
Total/NA	Analysis	SM 5310B		1	50 mL	50 mL	535562	08/09/18 08:59	VRP	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	379989	08/02/18 16:27	EAW	TAL SL
Total/NA	Analysis	901.1		1			380597	08/04/18 22:19	CDR	TAL SL
Total/NA	Prep	Evaporation			0.2 mL	1.0 g	381190	08/08/18 17:38	MRB	TAL SL
Total/NA	Analysis	9310		1			381569	08/10/18 08:14	RTM	TAL SL

Client Sample ID: Trip Blank

Lab Sample ID: 490-156673-2
Date Collected: 07/31/18 00:01
Matrix: Water
Date Received: 08/01/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	5 mL	5 mL	533015	08/01/18 17:28	RP	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-18 *
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-18 *
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-18 *
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-18 *
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156673-1
SDG: Woods Co. Miss Lime

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-19
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-18 *
Nevada	State Program	9	MO000542018-1	07-31-19
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-19
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-18 *
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-18 *
West Virginia DEP	State Program	3	381	08-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

490-156673 Chain of Custody

COOLER RECEIPT FORM

Cooler Received/Opened On_8/1/18 @ 10:00_____

Time Samples Removed From Cooler 1259 Time Samples Placed In Storage 1312 (2 Hour Window)

1. Tracking # 8136 (last 4 digits, FedEx) Courier: __

   IR Gun ID____17960353_____ pH Strip Lot HC740848 Chlorine Strip Lot 111417F

2. Temperature of rep. sample or temp blank when opened: 0.6 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 Front / 1 Back

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) KOF

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #_____

I certify that I unloaded the cooler and answered questions 7-14 (intial) GH

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) GH

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) GH

I certify that I attached a label with the unique LIMS number to each container (intial) GH

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment
Cooler Receipt Form.doc

LF-1
End of Form

Revised 8/23/17

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information	Sampler: Jarrod Maly	Lab PM: Gambill, Jennifer	Carrier Tracking No(s):	COC No:
Client Contact: Dr. James Rosenblum	Phone: 580 541 0319	E-Mail: jennifer.gambill@testamericainc.com		Page: Page of
Company: CH2M Hill, Inc.				Job #:
Address: 12377 Merit Drive Suite 1000	Due Date Requested:			
City: Dallas	TAT Requested (days):			
State, Zip: TX, 75251				
Phone: 248-939-3216(Tel)	PO #:			
Email: james.rosenblum@ch2m.com	WO #:			
Project Name: OWRB Study Phase II	Project #: 49013620			
Site: Woods Co. Miss Lime	SSOW#:			

Analysis Requested

Preservation Codes:

A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA, M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)

Other:

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		Loc: 490 156673
NORM (1)	7/31	9AM	G	W																	
Gross Alpha/Beta (1)	7/31	9AM	G	W																	
Alk/IC/pH (3)	7/31	9AM	G	W																	
Metals/Hardness (1)	7/31	9AM	G	W																	
TOC (1)	7/31	9AM	G	W																	
BTEX/GRO (6)	7/31	9AM	G	W																	
TDS (1)	7/31	9AM	G	W																	
DRO (2)	7/31	9AM	G	W																	
phosphorus (1)	7/31	9AM	G	W																	
			G	W																	

Possible Hazard Identification
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return To Client ☐ Disposal By Lab ☐ Archive For _____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: ~~Jacob Hernandez~~ Jarrod Maly	Date: 7-31-18	Time: 1:00pm		Method of Shipment: Hand delivered	
Relinquished by: Jarrod Maly	Date/Time: 7/31	Company: D&B	Received by: Fed Ex	Date/Time:	Company
Relinquished by:	Date/Time:	Company	Received by: Bey	Date/Time: 8-1-18/ 1000	Company: TA-NAS
Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 0.6

Ver: 08/04/2016

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-156682-1
TestAmerica Sample Delivery Group: Woods Co Chester
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Dr. James Rosenblum

Jennifer Gambill

Authorized for release by:
8/17/2018 1:38:22 PM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-156682-1	Woods Co Chester	Water	07/31/18 10:00	08/01/18 10:00
490-156682-2	Trip Blank	Water	07/31/18 00:01	08/01/18 10:00

Job ID: 490-156682-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-156682-1

Comments
No additional comments.

Receipt
The samples were received on 8/1/2018 10:00 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 1.3º C.

GC/MS VOA
Method(s) 8260B: The following volatile sample was analyzed with significant headspace in the sample container: Trip Blank (490-156682-2). Significant headspace is defined as a bubble greater than 6 mm in diameter.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

HPLC/IC
Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Woods Co Chester (490-156682-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: Reanalysis of the following sample was performed outside of the analytical holding time due dilution: Woods Co Chester (490-156682-1).

Method(s) 300.0: The method blank for preparation batch 490-533802 contained Nitrate as N above the reporting limit (RL). None of the samples associated with this method blank contained the target compound; therefore, re-extraction and/or re-analysis of samples were not performed.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC VOA
Method(s) OK GRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate/sample duplicate (MS/MSD/DUP) associated with analytical batch 490-533562.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-533551 and analytical batch 490-533965.

Method(s) OK DRO: The following sample was diluted due to abundance of target analytes: Woods Co Chester (490-156682-1). As such, surrogate recoveries are below the calibration range or are not reported, and elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Metals
Method(s) 200.7 Rev 4.4: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for preparation batch 490-533242 and analytical batch 490-533579 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits. (490-155787-A-5-C MS) and (490-155787-A-5-D MSD)

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

General Chemistry
Method(s) SM 5310B: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-535562 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Job ID: 490-156682-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD

Method(s) 901.1: Gamma Prep Batch 160-379989: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Woods Co Chester (490-156682-1), (LCS 160-379989/2-A), (MB 160-379989/1-A) and (490-156682-O-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-379989: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative. Woods Co Chester (490-156682-1), (MB 160-379989/1-A) and (490-156682-O-1-B DU).

Method(s) 9310: Gross Alpha/Beta Prep Batch 160-381190: The gross alpha and beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Woods Co Chester (490-156682-1), (180-79813-H-1-A) and (180-79813-H-1-D DU). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Qualifiers

GC Semi VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

HPLC/IC

Qualifier	Qualifier Description
H	Sample was prepped or analyzed beyond the specified holding time
E	Result exceeded calibration range.
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.

Metals

Qualifier	Qualifier Description
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.
F1	MS and/or MSD Recovery is outside acceptance limits.
B	Compound was found in the blank and sample.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

General Chemistry

Qualifier	Qualifier Description
E	Result exceeded calibration range.
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.
F1	MS and/or MSD Recovery is outside acceptance limits.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points

Glossary (Continued)

Abbreviation	These commonly used abbreviations may or may not be present in this report.
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Client Sample ID: Woods Co Chester

Lab Sample ID: 490-156682-1

Date Collected: 07/31/18 10:00
Date Received: 08/01/18 10:00

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	1350		5.00	1.00	ug/L			08/01/18 22:42	5
Ethylbenzene	71.2		5.00	0.950	ug/L			08/01/18 22:42	5
Toluene	889		5.00	0.850	ug/L			08/01/18 22:42	5
Xylenes, Total	477		15.0	2.90	ug/L			08/01/18 22:42	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*78*		*70 - 130*		*08/01/18 22:42*	*5*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*		*08/01/18 22:42*	*5*
Dibromofluoromethane (Surr)	*88*		*70 - 130*		*08/01/18 22:42*	*5*
Toluene-d8 (Surr)	*92*		*70 - 130*		*08/01/18 22:42*	*5*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	3190		20.0	10.0	ug/L			08/03/18 13:23	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*74*		*70 - 130*		*08/03/18 13:23*	*1*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	116000		22700	11400	ug/L		08/03/18 06:18	08/06/18 15:28	250

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*0*	*X*	*50 - 150*	*08/03/18 06:18*	*08/06/18 15:28*	*250*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	331		50.0	2.50	mg/L			08/03/18 12:35	50
Nitrate as N	ND	H	5.00	2.50	mg/L			08/03/18 12:35	50
Chloride	41900		5000	3500	mg/L			08/03/18 12:53	5000
Nitrite as N	ND	H	5.00	2.50	mg/L			08/03/18 12:35	50
Fluoride	18.0		5.00	3.00	mg/L			08/03/18 12:35	50
Sulfate	299		50.0	30.0	mg/L			08/03/18 12:35	50

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.782	B	0.500	0.250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Antimony	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Arsenic	ND		0.0500	0.0430	mg/L		08/02/18 07:52	08/03/18 17:58	5
Barium	2.87		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Beryllium	ND		0.0200	0.0100	mg/L		08/02/18 07:52	08/03/18 17:58	5
Cadmium	ND		0.00500	0.00250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Calcium	3670		50.0	25.0	mg/L		08/02/18 07:52	08/04/18 17:18	50
Chromium	ND		0.0250	0.0150	mg/L		08/02/18 07:52	08/03/18 17:58	5
Cobalt	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Copper	0.0415	J	0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Iron	19.8		0.500	0.250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Lead	0.0225	J	0.0250	0.0100	mg/L		08/02/18 07:52	08/03/18 17:58	5
Magnesium	700		50.0	12.5	mg/L		08/02/18 07:52	08/04/18 17:18	50
Manganese	1.30		0.0750	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Nickel	ND		0.0500	0.0150	mg/L		08/02/18 07:52	08/03/18 17:58	5

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Client Sample ID: Woods Co Chester

Lab Sample ID: 490-156682-1

Date Collected: 07/31/18 10:00
Matrix: Water
Date Received: 08/01/18 10:00

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Potassium	**120**		5.00	2.50	mg/L		08/02/18 07:52	08/03/18 17:58	5
Selenium	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Silver	ND		0.0250	0.0150	mg/L		08/02/18 07:52	08/03/18 17:58	5
Sodium	**26700**		100	40.0	mg/L		08/02/18 07:52	08/07/18 17:35	100
Thallium	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 17:58	5
Vanadium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/04/18 17:18	50
Zinc	ND		0.250	0.125	mg/L		08/02/18 07:52	08/03/18 17:58	5

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**12000**		10.0	5.00	mg/L			08/14/18 16:05	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	**0.200**		0.100	0.0500	mg/L		08/08/18 09:56	08/08/18 21:34	1
Bicarbonate Alkalinity as CaCO3	**259**		10.0	5.00	mg/L			08/03/18 21:39	1
Alkalinity	**259**		10.0	5.00	mg/L			08/03/18 21:39	1
Total Dissolved Solids	**86800**		1000	700	mg/L			08/02/18 16:00	1
pH	**6.8**	**HF**	0.1	0.1	SU			08/02/18 17:11	1
Total Organic Carbon	**108**		3.13	1.57	mg/L			08/09/18 08:59	3.13

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	27.8	U	61.5	61.6		115	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Actinium-228	**122**		33.6	35.6		29.9	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Bismuth-212	69.5	U	120	120		201	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Bismuth-214	**214**		32.0	38.5		22.6	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Lead-210	101	U	163	164		230	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Lead-212	**55.0**		16.1	17.6		21.4	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Lead-214	**194**		26.1	33.0		24.5	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Potassium-40	74.9	U	174	174		218	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Protactinium-231	132	U	394	395		883	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Radium-226	**471**	**G**	226	239	125	259	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Radium-228	**122**		33.6	35.6		29.9	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Thallium-208	**15.8**		11.7	11.8		13.0	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Thorium-232	**122**		33.6	35.6		29.9	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Thorium-234	40.8	U	151	151		251	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Uranium-235	-22.1	U	33.0	33.1		141	pCi/L	08/02/18 16:27	08/04/18 21:09	1
Uranium-238	40.8	U	151	151		251	pCi/L	08/02/18 16:27	08/04/18 21:09	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*08/02/18 16:27*	*08/04/18 21:09*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Client Sample ID: Woods Co Chester

Lab Sample ID: 490-156682-1

Date Collected: 07/31/18 10:00
Matrix: Water
Date Received: 08/01/18 10:00

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	465	U G	476	479	3.00	765	pCi/L	08/08/18 17:38	08/10/18 08:14	1
Gross Beta	338	U G	234	236	4.00	352	pCi/L	08/08/18 17:38	08/10/18 08:14	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Client Sample ID: Trip Blank

Lab Sample ID: 490-156682-2

Date Collected: 07/31/18 00:01
Date Received: 08/01/18 10:00

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/02/18 14:16	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/02/18 14:16	1
Toluene	ND		1.00	0.170	ug/L			08/02/18 14:16	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/02/18 14:16	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*74*		*70 - 130*		*08/02/18 14:16*	*1*
4-Bromofluorobenzene (Surr)	*102*		*70 - 130*		*08/02/18 14:16*	*1*
Dibromofluoromethane (Surr)	*80*		*70 - 130*		*08/02/18 14:16*	*1*
Toluene-d8 (Surr)	*94*		*70 - 130*		*08/02/18 14:16*	*1*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-533001/8
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/01/18 15:49	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/01/18 15:49	1
Toluene	ND		1.00	0.170	ug/L			08/01/18 15:49	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/01/18 15:49	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*71*		*70 - 130*		*08/01/18 15:49*	*1*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*		*08/01/18 15:49*	*1*
Dibromofluoromethane (Surr)	*82*		*70 - 130*		*08/01/18 15:49*	*1*
Toluene-d8 (Surr)	*95*		*70 - 130*		*08/01/18 15:49*	*1*

Lab Sample ID: LCS 490-533001/5
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	21.36		ug/L		107	70 - 130
Ethylbenzene	20.0	20.16		ug/L		101	70 - 130
Toluene	20.0	19.19		ug/L		96	70 - 130
Xylenes, Total	40.0	39.83		ug/L		100	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*73*		*70 - 130*
4-Bromofluorobenzene (Surr)	*104*		*70 - 130*
Dibromofluoromethane (Surr)	*88*		*70 - 130*
Toluene-d8 (Surr)	*92*		*70 - 130*

Lab Sample ID: LCSD 490-533001/6
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	21.07		ug/L		105	70 - 130	1	12
Ethylbenzene	20.0	20.32		ug/L		102	70 - 130	1	12
Toluene	20.0	19.46		ug/L		97	70 - 130	1	13
Xylenes, Total	40.0	40.34		ug/L		101	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*72*		*70 - 130*
4-Bromofluorobenzene (Surr)	*105*		*70 - 130*
Dibromofluoromethane (Surr)	*84*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-156591-B-1 MS
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	22.20		ug/L		111	55 - 147
Ethylbenzene	ND		20.0	21.11		ug/L		106	65 - 139
Toluene	ND		20.0	20.28		ug/L		101	64 - 136
Xylenes, Total	ND		40.0	41.93		ug/L		105	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*74*		*70 - 130*
4-Bromofluorobenzene (Surr)	*104*		*70 - 130*
Dibromofluoromethane (Surr)	*82*		*70 - 130*
Toluene-d8 (Surr)	*91*		*70 - 130*

Lab Sample ID: 490-156591-C-1 MSD
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	22.73		ug/L		114	55 - 147	2	22
Ethylbenzene	ND		20.0	21.98		ug/L		110	65 - 139	4	18
Toluene	ND		20.0	20.91		ug/L		105	64 - 136	3	18
Xylenes, Total	ND		40.0	43.70		ug/L		109	69 - 132	4	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*75*		*70 - 130*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*
Dibromofluoromethane (Surr)	*82*		*70 - 130*
Toluene-d8 (Surr)	*92*		*70 - 130*

Lab Sample ID: MB 490-533312/7
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/02/18 13:21	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/02/18 13:21	1
Toluene	ND		1.00	0.170	ug/L			08/02/18 13:21	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/02/18 13:21	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*73*		*70 - 130*		*08/02/18 13:21*	*1*
4-Bromofluorobenzene (Surr)	*103*		*70 - 130*		*08/02/18 13:21*	*1*
Dibromofluoromethane (Surr)	*81*		*70 - 130*		*08/02/18 13:21*	*1*
Toluene-d8 (Surr)	*94*		*70 - 130*		*08/02/18 13:21*	*1*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: LCS 490-533312/4
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	20.99		ug/L		105	70 - 130
Ethylbenzene	20.0	20.04		ug/L		100	70 - 130
Toluene	20.0	19.17		ug/L		96	70 - 130
Xylenes, Total	40.0	39.57		ug/L		99	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*78*		*70 - 130*
4-Bromofluorobenzene (Surr)	*104*		*70 - 130*
Dibromofluoromethane (Surr)	*87*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Lab Sample ID: LCSD 490-533312/5
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	20.53		ug/L		103	70 - 130	2	12
Ethylbenzene	20.0	19.92		ug/L		100	70 - 130	1	12
Toluene	20.0	18.89		ug/L		94	70 - 130	1	13
Xylenes, Total	40.0	39.20		ug/L		98	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*72*		*70 - 130*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*
Dibromofluoromethane (Surr)	*85*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Lab Sample ID: 490-156656-B-1 MS
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	22.47		ug/L		112	55 - 147
Ethylbenzene	ND		20.0	21.88		ug/L		109	65 - 139
Toluene	ND		20.0	20.53		ug/L		103	64 - 136
Xylenes, Total	ND		40.0	43.00		ug/L		108	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*75*		*70 - 130*
4-Bromofluorobenzene (Surr)	*107*		*70 - 130*
Dibromofluoromethane (Surr)	*88*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-156656-C-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533312

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	21.80		ug/L		109	55 - 147	3	22
Ethylbenzene	ND		20.0	21.25		ug/L		106	65 - 139	3	18
Toluene	ND		20.0	19.82		ug/L		99	64 - 136	4	18
Xylenes, Total	ND		40.0	42.35		ug/L		106	69 - 132	2	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*78*		*70 - 130*
4-Bromofluorobenzene (Surr)	*107*		*70 - 130*
Dibromofluoromethane (Surr)	*88*		*70 - 130*
Toluene-d8 (Surr)	*92*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-533562/6 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			08/03/18 10:36	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*99*		*70 - 130*		*08/03/18 10:36*	*1*

Lab Sample ID: LCS 490-533562/5 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
C6-C10 OK			200	183.1		ug/L		92	80 - 120		

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*100*		*70 - 130*

Lab Sample ID: LCSD 490-533562/11 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK			200	205.7		ug/L		103	80 - 120	12	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*103*		*70 - 130*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-533551/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533965 — **Prep Batch: 533551**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		08/03/18 06:18	08/05/18 10:17	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*84*		*50 - 150*	*08/03/18 06:18*	*08/05/18 10:17*	*1*

Lab Sample ID: LCS 490-533551/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533965 — **Prep Batch: 533551**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	478.1		ug/L		96	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*104*		*50 - 150*

Lab Sample ID: LCSD 490-533551/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533965 — **Prep Batch: 533551**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	514.0		ug/L		103	80 - 120	7	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*112*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-533801/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			08/03/18 11:13	1
Chloride	ND		1.00	0.700	mg/L			08/03/18 11:13	1
Fluoride	ND		0.100	0.0600	mg/L			08/03/18 11:13	1
Sulfate	ND		1.00	0.600	mg/L			08/03/18 11:13	1

Lab Sample ID: LCS 490-533801/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.995		mg/L		100	90 - 110
Chloride	10.0	9.180		mg/L		92	90 - 110
Fluoride	1.00	0.9665		mg/L		97	90 - 110
Sulfate	10.0	9.763		mg/L		97	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-533801/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.987		mg/L		100	90 - 110	0	20
Chloride	10.0	9.163		mg/L		92	90 - 110	0	20
Fluoride	1.00	0.9722		mg/L		97	90 - 110	1	20
Sulfate	10.0	9.751		mg/L		97	90 - 110	0	20

Lab Sample ID: 490-156768-E-2 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	1.55		10.0	11.78	E	mg/L		102	80 - 120
Chloride	231	E	10.0	240.5	E 4	mg/L		99	80 - 120
Fluoride	0.780		1.00	1.743		mg/L		96	80 - 120
Sulfate	198	E	10.0	208.1	E 4	mg/L		99	80 - 120

Lab Sample ID: MB 490-533802/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			08/03/18 11:13	1
Nitrite as N	ND		0.100	0.0500	mg/L			08/03/18 11:13	1

Lab Sample ID: LCS 490-533802/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	0.9491		mg/L		95	90 - 110
Nitrite as N	1.00	0.9334		mg/L		93	90 - 110

Lab Sample ID: LCSD 490-533802/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	0.9398		mg/L		94	90 - 110	1	20
Nitrite as N	1.00	0.9333		mg/L		93	90 - 110	0	20

Lab Sample ID: 490-156768-E-2 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	ND		1.00	0.9317		mg/L		93	80 - 120
Nitrite as N	ND		1.00	1.073		mg/L		107	80 - 120

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-533242/1-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 533242

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.06190	J	0.100	0.0500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Antimony	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Arsenic	ND		0.0100	0.00860	mg/L		08/02/18 07:52	08/02/18 16:38	1
Barium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Beryllium	ND		0.00400	0.00200	mg/L		08/02/18 07:52	08/02/18 16:38	1
Cadmium	ND		0.00100	0.000500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Calcium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Chromium	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/02/18 16:38	1
Cobalt	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Copper	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Lead	ND		0.00500	0.00200	mg/L		08/02/18 07:52	08/02/18 16:38	1
Magnesium	ND		1.00	0.250	mg/L		08/02/18 07:52	08/02/18 16:38	1
Manganese	ND		0.0150	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Nickel	ND		0.0100	0.00300	mg/L		08/02/18 07:52	08/02/18 16:38	1
Selenium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Silver	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/02/18 16:38	1
Thallium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/02/18 16:38	1
Vanadium	ND		0.0200	0.0100	mg/L		08/02/18 07:52	08/02/18 16:38	1
Zinc	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/02/18 16:38	1

Lab Sample ID: MB 490-533242/1-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 533242

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Iron	ND		0.100	0.0500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Potassium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Sodium	ND		1.00	0.400	mg/L		08/02/18 07:52	08/03/18 16:56	1

Lab Sample ID: LCS 490-533242/2-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.081		mg/L		108	85 - 115
Antimony	0.100	0.1033		mg/L		103	85 - 115
Arsenic	0.100	0.1027		mg/L		103	85 - 115
Barium	0.100	0.1030		mg/L		103	85 - 115
Beryllium	0.100	0.09980		mg/L		100	85 - 115
Cadmium	0.100	0.1059		mg/L		106	85 - 115
Calcium	10.0	10.05		mg/L		101	85 - 115
Chromium	0.100	0.1079		mg/L		108	85 - 115
Cobalt	0.100	0.1057		mg/L		106	85 - 115
Copper	0.100	0.09970		mg/L		100	85 - 115
Lead	0.100	0.1074		mg/L		107	85 - 115
Magnesium	10.0	9.763		mg/L		98	85 - 115
Manganese	0.100	0.1095		mg/L		110	85 - 115
Nickel	0.100	0.1063		mg/L		106	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-533242/2-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Selenium	0.100	0.1108		mg/L		111	85 - 115
Silver	0.100	0.1018		mg/L		102	85 - 115
Thallium	0.100	0.1055		mg/L		106	85 - 115
Vanadium	0.100	0.09400		mg/L		94	85 - 115
Zinc	0.100	0.1077		mg/L		108	85 - 115

Lab Sample ID: LCS 490-533242/2-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Iron	1.00	0.9806		mg/L		98	85 - 115
Potassium	10.0	10.93		mg/L		109	85 - 115
Sodium	10.0	10.65		mg/L		107	85 - 115

Lab Sample ID: LCSD 490-533242/3-A
Matrix: Water
Analysis Batch: 533579

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.066		mg/L		107	85 - 115	1	20
Antimony	0.100	0.1036		mg/L		104	85 - 115	0	20
Arsenic	0.100	0.1026		mg/L		103	85 - 115	0	20
Barium	0.100	0.1017		mg/L		102	85 - 115	1	20
Beryllium	0.100	0.09790		mg/L		98	85 - 115	2	20
Cadmium	0.100	0.1050		mg/L		105	85 - 115	1	20
Calcium	10.0	9.948		mg/L		99	85 - 115	1	20
Chromium	0.100	0.1070		mg/L		107	85 - 115	1	20
Cobalt	0.100	0.1051		mg/L		105	85 - 115	1	20
Copper	0.100	0.1005		mg/L		101	85 - 115	1	20
Lead	0.100	0.1078		mg/L		108	85 - 115	0	20
Magnesium	10.0	9.616		mg/L		96	85 - 115	2	20
Manganese	0.100	0.1086		mg/L		109	85 - 115	1	20
Nickel	0.100	0.1062		mg/L		106	85 - 115	0	20
Selenium	0.100	0.1104		mg/L		110	85 - 115	0	20
Silver	0.100	0.1011		mg/L		101	85 - 115	1	20
Thallium	0.100	0.1083		mg/L		108	85 - 115	3	20
Vanadium	0.100	0.09310		mg/L		93	85 - 115	1	20
Zinc	0.100	0.1071		mg/L		107	85 - 115	1	20

Lab Sample ID: LCSD 490-533242/3-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Iron	1.00	0.9670		mg/L		97	85 - 115	1	20
Potassium	10.0	10.82		mg/L		108	85 - 115	1	20
Sodium	10.0	10.48		mg/L		105	85 - 115	2	20

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: 490-155787-A-5-C MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533579 — **Prep Batch: 533242**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	0.389	B	1.00	1.394		mg/L		101	70 - 130
Arsenic	ND		0.100	0.1099		mg/L		110	70 - 130
Beryllium	ND		0.100	0.09460		mg/L		95	70 - 130
Cadmium	ND		0.100	0.09890		mg/L		99	70 - 130
Calcium	179		10.0	189.2	4	mg/L		103	70 - 130
Chromium	ND		0.100	0.1028		mg/L		103	70 - 130
Cobalt	ND		0.100	0.09790		mg/L		98	70 - 130
Copper	ND		0.100	0.09900		mg/L		99	70 - 130
Lead	ND		0.100	0.09880		mg/L		99	70 - 130
Manganese	0.304	F1	0.100	0.4066		mg/L		103	70 - 130
Nickel	ND		0.100	0.1004		mg/L		100	70 - 130
Silver	ND		0.100	0.09630		mg/L		96	70 - 130
Thallium	ND		0.100	0.09260		mg/L		93	70 - 130
Vanadium	ND		0.100	0.09820		mg/L		98	70 - 130
Zinc	ND		0.100	0.1037		mg/L		104	70 - 130

Lab Sample ID: 490-155787-A-5-D MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533579 — **Prep Batch: 533242**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	0.389	B	1.00	1.420		mg/L		103	70 - 130	2	20
Arsenic	ND		0.100	0.1091		mg/L		109	70 - 130	1	20
Beryllium	ND		0.100	0.09810		mg/L		98	70 - 130	4	20
Cadmium	ND		0.100	0.1020		mg/L		102	70 - 130	3	20
Calcium	179		10.0	206.0	4	mg/L		271	70 - 130	9	20
Chromium	ND		0.100	0.1068		mg/L		107	70 - 130	4	20
Cobalt	ND		0.100	0.1013		mg/L		101	70 - 130	3	20
Copper	ND		0.100	0.1010		mg/L		101	70 - 130	2	20
Lead	ND		0.100	0.1033		mg/L		103	70 - 130	4	20
Manganese	0.304	F1	0.100	0.4374	F1	mg/L		133	70 - 130	7	20
Nickel	ND		0.100	0.1040		mg/L		104	70 - 130	4	20
Silver	ND		0.100	0.1000		mg/L		100	70 - 130	4	20
Thallium	ND		0.100	0.09660		mg/L		97	70 - 130	4	20
Vanadium	ND		0.100	0.1035		mg/L		104	70 - 130	5	20
Zinc	ND		0.100	0.1070		mg/L		107	70 - 130	3	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-534597/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		08/08/18 09:56	08/08/18 21:21	1

Method: 365.4 - Phosphorus, Total (Continued)

Lab Sample ID: LCS 490-534597/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	1.880		mg/L		94	90 - 110

Lab Sample ID: LCSD 490-534597/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.00	1.880		mg/L		94	90 - 110	0	20

Lab Sample ID: 490-156790-A-1-E MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	3.88		2.00	5.830		mg/L		98	73 - 119

Lab Sample ID: 490-156790-A-1-F MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	3.88		2.00	5.570		mg/L		85	73 - 119	5	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-534146/37 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			08/03/18 21:17	1
Alkalinity	ND		10.0	5.00	mg/L			08/03/18 21:17	1

Lab Sample ID: LCS 490-534146/38 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	96.13		mg/L		96	90 - 110

Lab Sample ID: LCSD 490-534146/46 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity	100	99.81		mg/L		100	90 - 110	4	20

Method: SM 2320B - Alkalinity (Continued)

Lab Sample ID: 490-156744-I-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	481			481.9		mg/L				0.2	20
Alkalinity	481			481.9		mg/L				0.2	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-533354/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			08/02/18 16:00	1

Lab Sample ID: LCS 490-533354/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Dissolved Solids			100	100.0		mg/L		100	90 - 110		

Lab Sample ID: LCSD 490-533354/3 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Dissolved Solids			100	105.0		mg/L		105	90 - 110	5	20

Lab Sample ID: 490-156658-F-2 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	5450	E		5364	E	mg/L				2	20

Lab Sample ID: 490-156724-G-2 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	86.0			84.00		mg/L				2	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-156656-G-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533505

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	7.1			7.1		SU				0	20

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: LB 490-535562/8 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	LB Result	LB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			08/09/18 08:59	1

Lab Sample ID: MB 490-535562/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			08/09/18 08:59	1

Lab Sample ID: LCS 490-535562/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	10.0	10.55		mg/L		105	90 - 110

Lab Sample ID: LCSD 490-535562/7 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	10.0	10.42		mg/L		104	90 - 110	1	20

Lab Sample ID: 490-157135-I-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	8.75	F1	20.0	21.94	F1	mg/L		66	74 - 134

Lab Sample ID: 490-157135-I-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535562

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	8.75	F1	20.0	22.57	F1	mg/L		69	74 - 134	3	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-379989/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380608 — **Prep Batch: 379989**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	35.39	U	56.4	56.6		111	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Actinium-228	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Bismuth-212	47.28	U	111	111		194	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Bismuth-214	0.0000	U	14.3	14.3		54.6	pCi/L	08/02/18 16:27	08/04/18 21:04	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: MB 160-379989/1-A
Matrix: Water
Analysis Batch: 380608

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 379989

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Lead-210	-101.8	U	145	147		261	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-212	-18.83	U	13.1	13.4		38.1	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-214	-16.07	U	21.4	21.4		40.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Potassium-40	-81.36	U	151	151		231	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Protactinium-231	0.0000	U	116	116		753	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Radium-226	-134.5	U G	196	197	125	351	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Radium-228	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thallium-208	0.9123	U	11.3	11.3		15.6	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thorium-232	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thorium-234	-41.42	U	137	137		237	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Uranium-235	-23.09	U	63.4	63.5		116	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Uranium-238	-41.42	U	137	137		237	pCi/L	08/02/18 16:27	08/04/18 21:04	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*08/02/18 16:27*	*08/04/18 21:04*	*1*

Lab Sample ID: LCS 160-379989/2-A
Matrix: Water
Analysis Batch: 380601

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 379989

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Americium-241	136000	133600		15400		526	pCi/L	98	90 - 111
Cesium-137	45500	43580		4380		163	pCi/L	96	90 - 111
Cobalt-60	32800	31570		3130		100	pCi/L	96	89 - 110

Lab Sample ID: 490-156682-1 DU
Matrix: Water
Analysis Batch: 380628

Client Sample ID: Woods Co Chester
Prep Type: Total/NA
Prep Batch: 379989

Analyte	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Actinium-227	27.8	U	-53.30	U	127		213	pCi/L	0.43	1
Actinium-228	122		133.8		57.1		49.7	pCi/L	0.13	1
Bismuth-212	69.5	U	67.44	U	115		196	pCi/L	0.01	1
Bismuth-214	214		163.0		39.6		32.0	pCi/L	0.65	1
Lead-210	101	U	195.8	U	181		234	pCi/L	0.28	1
Lead-212	55.0		53.54		19.6		23.8	pCi/L	0.04	1
Lead-214	194		144.8		35.6		31.0	pCi/L	0.72	1
Potassium-40	74.9	U	-36.11	U	239		291	pCi/L	0.27	1
Protactinium-231	132	U	-215.8	U	702		1180	pCi/L	0.32	1
Radium-226	471	G	-221.4	U G	497	125	480	pCi/L	0.94	1
Radium-228	122		133.8		57.1		49.7	pCi/L	0.13	1
Thallium-208	15.8		16.48	U	14.3		23.4	pCi/L	0.03	1
Thorium-232	122		133.8		57.1		49.7	pCi/L	0.13	1
Thorium-234	40.8	U	35.69	U	291		487	pCi/L	0.01	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: 490-156682-1 DU — **Client Sample ID: Woods Co Chester**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380628 — **Prep Batch: 379989**

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Uranium-235	-22.1	U		9.942	U	37.4		228	pCi/L			0.46	1
Uranium-238	40.8	U		35.69	U	291		487	pCi/L			0.01	1

Other Detected Radionuclides	*Sample Result*	*Sample Qual*		*DU Result*	*DU Qual*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*			*RER*	*RER Limit*
Other Detected Radionuclide	*None*			*None*					*pCi/L*				

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-381190/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.9739		0.586	0.596	3.00	0.780	pCi/L	08/08/18 17:38	08/10/18 08:12	1
Gross Beta	0.08253	U	0.530	0.530	4.00	0.912	pCi/L	08/08/18 17:38	08/10/18 08:12	1

Lab Sample ID: LCS 160-381190/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha			51.0	38.76		5.76	3.00	1.36	pCi/L	76	73 - 133		

Lab Sample ID: LCSB 160-381190/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte			Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta			88.0	84.66		8.99	4.00	0.939	pCi/L	96	75 - 125		

Lab Sample ID: 180-79813-H-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha	88.1	G	637	545.3		85.5	3.00	22.5	pCi/L	72	60 - 140		

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Method: 9310 - Gross Alpha / Beta (GFPC) (Continued)

Lab Sample ID: 180-79813-H-1-C MSBT
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta	28.5	G	1100	1116	G	118	4.00	13.0	pCi/L	99	60 - 140		

Lab Sample ID: 180-79813-H-1-D DU
Matrix: Water
Analysis Batch: 381569

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 381190

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Gross Alpha	88.1	G		64.27	G	23.8	3.00	24.4	pCi/L			0.47	1
Gross Beta	28.5	G		31.93	G	10.4	4.00	12.2	pCi/L			0.16	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

GC/MS VOA

Analysis Batch: 533001

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	8260B	
MB 490-533001/8	Method Blank	Total/NA	Water	8260B	
LCS 490-533001/5	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-533001/6	Lab Control Sample Dup	Total/NA	Water	8260B	
490-156591-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-156591-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

Analysis Batch: 533312

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-2	Trip Blank	Total/NA	Water	8260B	
MB 490-533312/7	Method Blank	Total/NA	Water	8260B	
LCS 490-533312/4	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-533312/5	Lab Control Sample Dup	Total/NA	Water	8260B	
490-156656-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-156656-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 533562

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	OK GRO	
MB 490-533562/6	Method Blank	Total/NA	Water	OK GRO	
LCS 490-533562/5	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-533562/11	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 533551

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	3510C	
MB 490-533551/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-533551/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-533551/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 533965

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	OK DRO	533551
MB 490-533551/1-A	Method Blank	Total/NA	Water	OK DRO	533551
LCS 490-533551/2-A	Lab Control Sample	Total/NA	Water	OK DRO	533551
LCSD 490-533551/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	533551

HPLC/IC

Analysis Batch: 533801

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	300.0	
490-156682-1	Woods Co Chester	Total/NA	Water	300.0	
MB 490-533801/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533801/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533801/5	Lab Control Sample Dup	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 533801 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156768-E-2 MS	Matrix Spike	Total/NA	Water	300.0	

Analysis Batch: 533802

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	300.0	
MB 490-533802/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533802/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533802/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-156768-E-2 MS	Matrix Spike	Total/NA	Water	300.0	

Metals

Prep Batch: 533242

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	200.7	
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	
490-155787-A-5-C MS	Matrix Spike	Total/NA	Water	200.7	
490-155787-A-5-D MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	

Analysis Batch: 533579

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	533242
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	533242
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	533242
490-155787-A-5-C MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	533242
490-155787-A-5-D MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 533865

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	200.7 Rev 4.4	533242
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	533242
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	533242
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 534014

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 534542

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 536005

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	SM 2340B	

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

General Chemistry

Analysis Batch: 533354

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	SM 2540C	
MB 490-533354/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-533354/2	Lab Control Sample	Total/NA	Water	SM 2540C	
LCSD 490-533354/3	Lab Control Sample Dup	Total/NA	Water	SM 2540C	
490-156658-F-2 DU	Duplicate	Total/NA	Water	SM 2540C	
490-156724-G-2 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 533505

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	SM 4500 H+ B	
LCS 490-533505/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-156656-G-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 534146

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	SM 2320B	
MB 490-534146/37	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-534146/38	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-534146/46	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-156744-I-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Prep Batch: 534597

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	365.2/365.3/365	
MB 490-534597/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-534597/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-534597/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-156790-A-1-E MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-156790-A-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 534825

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	365.4	534597
MB 490-534597/1-A	Method Blank	Total/NA	Water	365.4	534597
LCS 490-534597/2-A	Lab Control Sample	Total/NA	Water	365.4	534597
LCSD 490-534597/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	534597
490-156790-A-1-E MS	Matrix Spike	Total/NA	Water	365.4	534597
490-156790-A-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	534597

Analysis Batch: 535562

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	SM 5310B	
LB 490-535562/8	Method Blank	Total/NA	Water	SM 5310B	
MB 490-535562/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-535562/6	Lab Control Sample	Total/NA	Water	SM 5310B	
LCSD 490-535562/7	Lab Control Sample Dup	Total/NA	Water	SM 5310B	
490-157135-I-1 MS	Matrix Spike	Total/NA	Water	SM 5310B	
490-157135-I-1 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Rad

Prep Batch: 379989

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	Fill_Geo-0	
MB 160-379989/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-379989/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
490-156682-1 DU	Woods Co Chester	Total/NA	Water	Fill_Geo-0	

Prep Batch: 381190

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156682-1	Woods Co Chester	Total/NA	Water	Evaporation	
MB 160-381190/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-381190/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-381190/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
180-79813-H-1-B MS	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-C MSBT	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-D DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Client Sample ID: Woods Co Chester

Lab Sample ID: 490-156682-1
Date Collected: 07/31/18 10:00
Matrix: Water
Date Received: 08/01/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		5	10 mL	10 mL	533001	08/01/18 22:42	P1B	TAL NSH
Total/NA	Analysis	OK GRO		1	5 mL	5 mL	533562	08/03/18 13:23	S1S	TAL NSH
Total/NA	Prep	3510C			1099.9 mL	1 mL	533551	08/03/18 06:18	CC	TAL NSH
Total/NA	Analysis	OK DRO		250			533965	08/06/18 15:28	PRB	TAL NSH
Total/NA	Analysis	300.0		50			533801	08/03/18 12:35	SW1	TAL NSH
Total/NA	Analysis	300.0		50			533802	08/03/18 12:35	SW1	TAL NSH
Total/NA	Analysis	300.0		5000			533801	08/03/18 12:53	SW1	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		5			533865	08/03/18 17:58	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		50			534014	08/04/18 17:18	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		100			534542	08/07/18 17:35	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			536005	08/14/18 16:05	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	534597	08/08/18 09:56	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	534825	08/08/18 21:34	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	534146	08/03/18 21:39	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	533354	08/02/18 16:00	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			533505	08/02/18 17:11	JDG	TAL NSH
Total/NA	Analysis	SM 5310B		3.13	50 mL	50 mL	535562	08/09/18 08:59	VRP	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	379989	08/02/18 16:27	EAW	TAL SL
Total/NA	Analysis	901.1		1			380597	08/04/18 21:09	CDR	TAL SL
Total/NA	Prep	Evaporation			0.5 mL	1.0 g	381190	08/08/18 17:38	MRB	TAL SL
Total/NA	Analysis	9310		1			381569	08/10/18 08:14	RTM	TAL SL

Client Sample ID: Trip Blank

Lab Sample ID: 490-156682-2
Date Collected: 07/31/18 00:01
Matrix: Water
Date Received: 08/01/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	10 mL	10 mL	533312	08/02/18 14:16	RP	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-18 *
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-18
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-18 *
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-18
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156682-1
SDG: Woods Co Chester

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-18 *
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-18 *
Nevada	State Program	9	MO000542018-1	07-31-18 *
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-18 *
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-18 *
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-18 *
West Virginia DEP	State Program	3	381	08-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-156682 Chain of Custody

Cooler Received/Opened On____08-01-2018_@__10:00_____

Time Samples Removed From Cooler 13:41 Time Samples Placed In Storage 13:52 (2 Hour Window)

1. Tracking # 8158 (last 4 digits, FedEx) Courier: _FedEx_

   IR Gun ID___14740456_____ pH Strip Lot HC849161 Chlorine Strip Lot 111417F

2. Temperature of rep. sample or temp blank when opened: 1.3 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 (front) + 1 (back)

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA KD 08-01-2018

I certify that I opened the cooler and answered questions 1-6 (intial) KD

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #_____

I certify that I unloaded the cooler and answered questions 7-14 (intial) KD

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) KD

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) KD

I certify that I attached a label with the unique LIMS number to each container (intial) KD

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information	Sampler: Jarrod Maly	Lab PM: Gambill, Jennifer	Carrier Tracking No(s):	COC No:
Client Contact: Dr. James Rosenblum	Phone: 580541 0319	E-Mail: jennifer.gambill@testamericainc.com		Page: Page of
Company: CH2M Hill, Inc.				Job #:
Address: 12377 Merit Drive Suite 1000	Due Date Requested:			
City: Dallas	TAT Requested (days):			
State, Zip: TX, 75251				
Phone: 248-939-3216(Tel)	PO #:			
Email: james.rosenblum@ch2m.com	WO #:			
Project Name: OWRB Study Phase II	Project #: 49013620			
Site: Woods co Chester	SSOW#:			

Analysis Requested

Preservation Codes:

A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA, M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)

Other:

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	7/31	10Am	G	W																	
Gross Alpha/Beta (1)	7/31	10Am	G	W																	
Alk/IC/pH (3)	7/31	10AM	G	W																	
Metals/Hardness (1)	7/31	10Am	G	W																	
TOC (1)	7/31	10Am	G	W																	
BTEX/GRO (6)	7/31	10Am	G	W																	
TDS (1)	7/31	10Am	G	W																	
DRO (2)	7/31	10Am	G	W																	
phosphorus (1)	7/31	10Am	G	W																	
			G	W																	

Loc: 490
156682

Possible Hazard Identification
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return To Client ☐ Disposal By Lab ☐ Archive For _____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: Jacob Hernandez	Date:	Time: 1:00 pm	Method of Shipment: Hand delivered	
Relinquished by: Jarrod Maly	Date/Time: 7/31/18	Company: DOB	Received by: FedEx	Date/Time:	Company
Relinquished by:	Date/Time:	Company	Received by: [signature]	Date/Time: 08-01-2018 16:00	Company: TA-NAS
Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company

Custody Seals Intact: Δ Yes Δ No	Custody Seal No.:	Cooler Temperature(s) °C and Other Remarks: 1.3

Ver: 08/04/2016

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-156688-1
TestAmerica Sample Delivery Group: Woods Co Meramec
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Dr. James Rosenblum

Jennifer Gambill

Authorized for release by:
8/17/2018 2:02:44 PM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

The test results in this report meet all 2003 NELAC and 2009 TNI requirements for accredited parameters, exceptions are noted in this report. This report may not be reproduced except in full, and with written approval from the laboratory. For questions please contact the Project Manager at the e-mail address or telephone number listed on this page.

This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-156688-1	Woods Co	Water	07/31/18 10:30	08/01/18 10:00
490-156688-2	Trip Blank	Water	07/31/18 10:30	08/01/18 10:00

Job ID: 490-156688-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-156688-1

Comments
No additional comments.

Receipt
The samples were received on 8/1/2018 10:00 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 1.5º C.

GC/MS VOA
Method(s) 8260B: The following volatile sample was analyzed with significant headspace in the sample container: Trip Blank (490-156688-2). Significant headspace is defined as a bubble greater than 6 mm in diameter.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

HPLC/IC
Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Woods Co (490-156688-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: Reanalysis of the following sample was performed outside of the analytical holding time due dilution: Woods Co (490-156688-1).

Method(s) 300.0: The method blank for preparation batch 490-533802 contained Nitrate as N above the reporting limit (RL). None of the samples associated with this method blank contained the target compound; therefore, re-extraction and/or re-analysis of samples were not performed.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC VOA
Method(s) OK GRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate/sample duplicate (MS/MSD/DUP) associated with analytical batch 490-533562.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-533551 and analytical batch 490-533965.

Method(s) OK DRO: The following sample was diluted due to abundance of target analytes: Woods Co (490-156688-1). As such, surrogate recoveries are below the calibration range or are not reported, and elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Metals
Method(s) 200.7 Rev 4.4: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for preparation batch 490-533242 and analytical batch 490-533579 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits. (490-155787-A-5-C MS) and (490-155787-A-5-D MSD)

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

General Chemistry
Method(s) 365.2/365.3/365: The following sample was diluted due to the nature of the sample matrix: Woods Co (490-156688-1). Elevated reporting limits (RLs) are provided.

Job ID: 490-156688-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

Method(s) SM 5310B: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-535562 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD

Method(s) 901.1: Gamma Prep Batch 160-379989: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Woods Co (490-156688-1), (LCS 160-379989/2-A), (MB 160-379989/1-A), (490-156682-O-1-A) and (490-156682-O-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-379989: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative. Woods Co (490-156688-1), (MB 160-379989/1-A), (490-156682-O-1-A) and (490-156682-O-1-B DU).

Method(s) 9310: Gross Alpha/Beta Prep Batch 160-381190: The gross alpha and beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Woods Co (490-156688-1), (180-79813-H-1-A) and (180-79813-H-1-D DU). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Qualifiers

GC Semi VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

HPLC/IC

Qualifier	Qualifier Description
H	Sample was prepped or analyzed beyond the specified holding time
E	Result exceeded calibration range.
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.

Metals

Qualifier	Qualifier Description
B	Compound was found in the blank and sample.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

General Chemistry

Qualifier	Qualifier Description
E	Result exceeded calibration range.
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Client Sample ID: Woods Co

Date Collected: 07/31/18 10:30
Date Received: 08/01/18 10:00

Lab Sample ID: 490-156688-1

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	1160		5.00	1.00	ug/L			08/01/18 23:10	5
Ethylbenzene	68.0		5.00	0.950	ug/L			08/01/18 23:10	5
Toluene	733		5.00	0.850	ug/L			08/01/18 23:10	5
Xylenes, Total	293		15.0	2.90	ug/L			08/01/18 23:10	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*80*		*70 - 130*		*08/01/18 23:10*	*5*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*		*08/01/18 23:10*	*5*
Dibromofluoromethane (Surr)	*87*		*70 - 130*		*08/01/18 23:10*	*5*
Toluene-d8 (Surr)	*90*		*70 - 130*		*08/01/18 23:10*	*5*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	2510		20.0	10.0	ug/L			08/03/18 13:54	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*83*		*70 - 130*		*08/03/18 13:54*	*1*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	66100		8910	4460	ug/L		08/03/18 06:18	08/06/18 15:50	100

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*0*	*X*	*50 - 150*	*08/03/18 06:18*	*08/06/18 15:50*	*100*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	381		50.0	2.50	mg/L			08/03/18 13:29	50
Nitrate as N	ND	H	5.00	2.50	mg/L			08/03/18 13:29	50
Chloride	62300		5000	3500	mg/L			08/03/18 13:48	5000
Nitrite as N	ND	H	5.00	2.50	mg/L			08/03/18 13:29	50
Fluoride	5.61		5.00	3.00	mg/L			08/03/18 13:29	50
Sulfate	636		50.0	30.0	mg/L			08/03/18 13:29	50

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	1.01	B	0.500	0.250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Antimony	ND		0.0100	0.00500	mg/L		08/09/18 07:38	08/15/18 11:41	1
Arsenic	ND		0.0500	0.0430	mg/L		08/02/18 07:52	08/03/18 18:04	5
Barium	2.59		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Beryllium	ND		0.0200	0.0100	mg/L		08/02/18 07:52	08/03/18 18:04	5
Cadmium	ND		0.00500	0.00250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Calcium	5380		50.0	25.0	mg/L		08/02/18 07:52	08/04/18 17:23	50
Chromium	ND		0.0250	0.0150	mg/L		08/02/18 07:52	08/03/18 18:04	5
Cobalt	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Copper	0.0280	J	0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Iron	8.79		0.500	0.250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Lead	ND		0.0250	0.0100	mg/L		08/02/18 07:52	08/03/18 18:04	5
Magnesium	1140		50.0	12.5	mg/L		08/02/18 07:52	08/04/18 17:23	50
Manganese	0.405		0.0750	0.0250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Nickel	ND		0.0500	0.0150	mg/L		08/02/18 07:52	08/03/18 18:04	5

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Client Sample ID: Woods Co

Date Collected: 07/31/18 10:30
Date Received: 08/01/18 10:00

Lab Sample ID: 490-156688-1

Matrix: Water

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Potassium	**479**		5.00	2.50	mg/L		08/02/18 07:52	08/03/18 18:04	5
Selenium	ND		0.0100	0.00500	mg/L		08/09/18 07:38	08/15/18 11:41	1
Silver	ND		0.0250	0.0150	mg/L		08/02/18 07:52	08/03/18 18:04	5
Sodium	**30600**		200	80.0	mg/L		08/02/18 07:52	08/07/18 17:40	200
Thallium	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 18:04	5
Vanadium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/04/18 17:23	50
Zinc	ND		0.250	0.125	mg/L		08/02/18 07:52	08/03/18 18:04	5

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**18100**		10.0	5.00	mg/L			08/14/18 16:05	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	**0.149**		0.100	0.0500	mg/L		08/08/18 09:56	08/08/18 21:37	1
Bicarbonate Alkalinity as CaCO3	**115**		10.0	5.00	mg/L			08/03/18 21:45	1
Alkalinity	**115**		10.0	5.00	mg/L			08/03/18 21:45	1
Total Dissolved Solids	**117000**		1000	700	mg/L			08/02/18 16:00	1
pH	**6.8**	**HF**	0.1	0.1	SU			08/02/18 17:11	1
Total Organic Carbon	**55.5**		2.00	1.00	mg/L			08/14/18 21:32	2

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	-40.1	U	147	147		247	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Actinium-228	**105**		71.5	72.3		74.1	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Bismuth-212	-73.6	U	204	204		350	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Bismuth-214	**311**		49.2	58.2		35.8	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Lead-210	228	U	250	254		310	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Lead-212	29.5	U	20.2	20.5		30.9	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Lead-214	**372**		44.2	58.7		36.7	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Potassium-40	**402**		160	165		156	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Protactinium-231	-90.1	U	836	836		1410	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Radium-226	**757**	**G**	361	383	125	402	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Radium-228	**105**		71.5	72.3		74.1	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Thallium-208	15.9	U	15.3	15.3		17.7	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Thorium-232	**105**		71.5	72.3		74.1	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Thorium-234	-250	U	254	255		551	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Uranium-235	-59.6	U	131	131		264	pCi/L	08/02/18 16:27	08/04/18 22:18	1
Uranium-238	-250	U	254	255		551	pCi/L	08/02/18 16:27	08/04/18 22:18	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*08/02/18 16:27*	*08/04/18 22:18*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Client Sample ID: Woods Co

Date Collected: 07/31/18 10:30
Date Received: 08/01/18 10:00

Lab Sample ID: 490-156688-1

Matrix: Water

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	**725**	**G**	476	483	3.00	640	pCi/L	08/08/18 17:38	08/10/18 08:14	1
Gross Beta	304	U G	245	247	4.00	376	pCi/L	08/08/18 17:38	08/10/18 08:14	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Client Sample ID: Trip Blank

Lab Sample ID: 490-156688-2

Date Collected: 07/31/18 10:30
Date Received: 08/01/18 10:00

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/02/18 14:44	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/02/18 14:44	1
Toluene	ND		1.00	0.170	ug/L			08/02/18 14:44	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/02/18 14:44	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*73*		*70 - 130*		*08/02/18 14:44*	*1*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*		*08/02/18 14:44*	*1*
Dibromofluoromethane (Surr)	*82*		*70 - 130*		*08/02/18 14:44*	*1*
Toluene-d8 (Surr)	*94*		*70 - 130*		*08/02/18 14:44*	*1*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-533001/8
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/01/18 15:49	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/01/18 15:49	1
Toluene	ND		1.00	0.170	ug/L			08/01/18 15:49	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/01/18 15:49	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*71*		*70 - 130*		*08/01/18 15:49*	*1*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*		*08/01/18 15:49*	*1*
Dibromofluoromethane (Surr)	*82*		*70 - 130*		*08/01/18 15:49*	*1*
Toluene-d8 (Surr)	*95*		*70 - 130*		*08/01/18 15:49*	*1*

Lab Sample ID: LCS 490-533001/5
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	21.36		ug/L		107	70 - 130
Ethylbenzene	20.0	20.16		ug/L		101	70 - 130
Toluene	20.0	19.19		ug/L		96	70 - 130
Xylenes, Total	40.0	39.83		ug/L		100	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*73*		*70 - 130*
4-Bromofluorobenzene (Surr)	*104*		*70 - 130*
Dibromofluoromethane (Surr)	*88*		*70 - 130*
Toluene-d8 (Surr)	*92*		*70 - 130*

Lab Sample ID: LCSD 490-533001/6
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	21.07		ug/L		105	70 - 130	1	12
Ethylbenzene	20.0	20.32		ug/L		102	70 - 130	1	12
Toluene	20.0	19.46		ug/L		97	70 - 130	1	13
Xylenes, Total	40.0	40.34		ug/L		101	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*72*		*70 - 130*
4-Bromofluorobenzene (Surr)	*105*		*70 - 130*
Dibromofluoromethane (Surr)	*84*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-156591-B-1 MS
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	22.20		ug/L		111	55 - 147
Ethylbenzene	ND		20.0	21.11		ug/L		106	65 - 139
Toluene	ND		20.0	20.28		ug/L		101	64 - 136
Xylenes, Total	ND		40.0	41.93		ug/L		105	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*74*		*70 - 130*
4-Bromofluorobenzene (Surr)	*104*		*70 - 130*
Dibromofluoromethane (Surr)	*82*		*70 - 130*
Toluene-d8 (Surr)	*91*		*70 - 130*

Lab Sample ID: 490-156591-C-1 MSD
Matrix: Water
Analysis Batch: 533001

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	22.73		ug/L		114	55 - 147	2	22
Ethylbenzene	ND		20.0	21.98		ug/L		110	65 - 139	4	18
Toluene	ND		20.0	20.91		ug/L		105	64 - 136	3	18
Xylenes, Total	ND		40.0	43.70		ug/L		109	69 - 132	4	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*75*		*70 - 130*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*
Dibromofluoromethane (Surr)	*82*		*70 - 130*
Toluene-d8 (Surr)	*92*		*70 - 130*

Lab Sample ID: MB 490-533312/7
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/02/18 13:21	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/02/18 13:21	1
Toluene	ND		1.00	0.170	ug/L			08/02/18 13:21	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/02/18 13:21	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*73*		*70 - 130*		*08/02/18 13:21*	*1*
4-Bromofluorobenzene (Surr)	*103*		*70 - 130*		*08/02/18 13:21*	*1*
Dibromofluoromethane (Surr)	*81*		*70 - 130*		*08/02/18 13:21*	*1*
Toluene-d8 (Surr)	*94*		*70 - 130*		*08/02/18 13:21*	*1*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: LCS 490-533312/4
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	20.99		ug/L		105	70 - 130
Ethylbenzene	20.0	20.04		ug/L		100	70 - 130
Toluene	20.0	19.17		ug/L		96	70 - 130
Xylenes, Total	40.0	39.57		ug/L		99	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*78*		*70 - 130*
4-Bromofluorobenzene (Surr)	*104*		*70 - 130*
Dibromofluoromethane (Surr)	*87*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Lab Sample ID: LCSD 490-533312/5
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	20.53		ug/L		103	70 - 130	2	12
Ethylbenzene	20.0	19.92		ug/L		100	70 - 130	1	12
Toluene	20.0	18.89		ug/L		94	70 - 130	1	13
Xylenes, Total	40.0	39.20		ug/L		98	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*72*		*70 - 130*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*
Dibromofluoromethane (Surr)	*85*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Lab Sample ID: 490-156656-B-1 MS
Matrix: Water
Analysis Batch: 533312

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	22.47		ug/L		112	55 - 147
Ethylbenzene	ND		20.0	21.88		ug/L		109	65 - 139
Toluene	ND		20.0	20.53		ug/L		103	64 - 136
Xylenes, Total	ND		40.0	43.00		ug/L		108	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*75*		*70 - 130*
4-Bromofluorobenzene (Surr)	*107*		*70 - 130*
Dibromofluoromethane (Surr)	*88*		*70 - 130*
Toluene-d8 (Surr)	*93*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-156656-C-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533312

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	21.80		ug/L		109	55 - 147	3	22
Ethylbenzene	ND		20.0	21.25		ug/L		106	65 - 139	3	18
Toluene	ND		20.0	19.82		ug/L		99	64 - 136	4	18
Xylenes, Total	ND		40.0	42.35		ug/L		106	69 - 132	2	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*78*		*70 - 130*
4-Bromofluorobenzene (Surr)	*107*		*70 - 130*
Dibromofluoromethane (Surr)	*88*		*70 - 130*
Toluene-d8 (Surr)	*92*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-533562/6 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			08/03/18 10:36	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*99*		*70 - 130*		*08/03/18 10:36*	*1*

Lab Sample ID: LCS 490-533562/5 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
C6-C10 OK			200	183.1		ug/L		92	80 - 120		

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*100*		*70 - 130*

Lab Sample ID: LCSD 490-533562/11 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533562

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK			200	205.7		ug/L		103	80 - 120	12	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*103*		*70 - 130*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-533551/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533965 — **Prep Batch: 533551**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		08/03/18 06:18	08/05/18 10:17	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*84*		*50 - 150*	*08/03/18 06:18*	*08/05/18 10:17*	*1*

Lab Sample ID: LCS 490-533551/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533965 — **Prep Batch: 533551**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	478.1		ug/L		96	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*104*		*50 - 150*

Lab Sample ID: LCSD 490-533551/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533965 — **Prep Batch: 533551**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	514.0		ug/L		103	80 - 120	7	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*112*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-533801/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			08/03/18 11:13	1
Chloride	ND		1.00	0.700	mg/L			08/03/18 11:13	1
Fluoride	ND		0.100	0.0600	mg/L			08/03/18 11:13	1
Sulfate	ND		1.00	0.600	mg/L			08/03/18 11:13	1

Lab Sample ID: LCS 490-533801/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.995		mg/L		100	90 - 110
Chloride	10.0	9.180		mg/L		92	90 - 110
Fluoride	1.00	0.9665		mg/L		97	90 - 110
Sulfate	10.0	9.763		mg/L		97	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-533801/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.987		mg/L		100	90 - 110	0	20
Chloride	10.0	9.163		mg/L		92	90 - 110	0	20
Fluoride	1.00	0.9722		mg/L		97	90 - 110	1	20
Sulfate	10.0	9.751		mg/L		97	90 - 110	0	20

Lab Sample ID: 490-156768-E-2 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533801

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	1.55		10.0	11.78	E	mg/L		102	80 - 120
Chloride	231	E	10.0	240.5	E 4	mg/L		99	80 - 120
Fluoride	0.780		1.00	1.743		mg/L		96	80 - 120
Sulfate	198	E	10.0	208.1	E 4	mg/L		99	80 - 120

Lab Sample ID: MB 490-533802/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			08/03/18 11:13	1
Nitrite as N	ND		0.100	0.0500	mg/L			08/03/18 11:13	1

Lab Sample ID: LCS 490-533802/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	0.9491		mg/L		95	90 - 110
Nitrite as N	1.00	0.9334		mg/L		93	90 - 110

Lab Sample ID: LCSD 490-533802/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	0.9398		mg/L		94	90 - 110	1	20
Nitrite as N	1.00	0.9333		mg/L		93	90 - 110	0	20

Lab Sample ID: 490-156768-E-2 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533802

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	ND		1.00	0.9317		mg/L		93	80 - 120
Nitrite as N	ND		1.00	1.073		mg/L		107	80 - 120

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-533242/1-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 533242

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.09980	J	0.100	0.0500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Antimony	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Arsenic	ND		0.0100	0.00860	mg/L		08/02/18 07:52	08/03/18 16:56	1
Barium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Beryllium	ND		0.00400	0.00200	mg/L		08/02/18 07:52	08/03/18 16:56	1
Cadmium	ND		0.00100	0.000500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Chromium	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/03/18 16:56	1
Cobalt	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Copper	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Iron	ND		0.100	0.0500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Lead	ND		0.00500	0.00200	mg/L		08/02/18 07:52	08/03/18 16:56	1
Manganese	ND		0.0150	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Nickel	ND		0.0100	0.00300	mg/L		08/02/18 07:52	08/03/18 16:56	1
Potassium	ND		1.00	0.500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Selenium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Silver	ND		0.00500	0.00300	mg/L		08/02/18 07:52	08/03/18 16:56	1
Thallium	ND		0.0100	0.00500	mg/L		08/02/18 07:52	08/03/18 16:56	1
Zinc	ND		0.0500	0.0250	mg/L		08/02/18 07:52	08/03/18 16:56	1

Lab Sample ID: LCS 490-533242/2-A
Matrix: Water
Analysis Batch: 533865

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 533242

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.048		mg/L		105	85 - 115
Antimony	0.100	0.1037		mg/L		104	85 - 115
Arsenic	0.100	0.1049		mg/L		105	85 - 115
Barium	0.100	0.1054		mg/L		105	85 - 115
Beryllium	0.100	0.1012		mg/L		101	85 - 115
Cadmium	0.100	0.1036		mg/L		104	85 - 115
Chromium	0.100	0.1080		mg/L		108	85 - 115
Cobalt	0.100	0.1019		mg/L		102	85 - 115
Copper	0.100	0.1048		mg/L		105	85 - 115
Iron	1.00	0.9806		mg/L		98	85 - 115
Lead	0.100	0.1089		mg/L		109	85 - 115
Manganese	0.100	0.1060		mg/L		106	85 - 115
Nickel	0.100	0.1035		mg/L		104	85 - 115
Potassium	10.0	10.93		mg/L		109	85 - 115
Selenium	0.100	0.1072		mg/L		107	85 - 115
Silver	0.100	0.1002		mg/L		100	85 - 115
Thallium	0.100	0.1094		mg/L		109	85 - 115
Zinc	0.100	0.1047		mg/L		105	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCSD 490-533242/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533865 — **Prep Batch: 533242**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.030		mg/L		103	85 - 115	2	20
Antimony	0.100	0.1028		mg/L		103	85 - 115	1	20
Arsenic	0.100	0.1013		mg/L		101	85 - 115	3	20
Barium	0.100	0.1037		mg/L		104	85 - 115	2	20
Beryllium	0.100	0.1003		mg/L		100	85 - 115	1	20
Cadmium	0.100	0.1026		mg/L		103	85 - 115	1	20
Chromium	0.100	0.1072		mg/L		107	85 - 115	1	20
Cobalt	0.100	0.1008		mg/L		101	85 - 115	1	20
Copper	0.100	0.1008		mg/L		101	85 - 115	4	20
Iron	1.00	0.9670		mg/L		97	85 - 115	1	20
Lead	0.100	0.1059		mg/L		106	85 - 115	3	20
Manganese	0.100	0.1052		mg/L		105	85 - 115	1	20
Nickel	0.100	0.1031		mg/L		103	85 - 115	0	20
Potassium	10.0	10.82		mg/L		108	85 - 115	1	20
Selenium	0.100	0.1063		mg/L		106	85 - 115	1	20
Silver	0.100	0.09980		mg/L		100	85 - 115	0	20
Thallium	0.100	0.1082		mg/L		108	85 - 115	1	20
Zinc	0.100	0.1034		mg/L		103	85 - 115	1	20

Lab Sample ID: MB 490-534847/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Antimony	ND		0.0100	0.00500	mg/L		08/09/18 07:37	08/10/18 21:21	1
Selenium	ND		0.0100	0.00500	mg/L		08/09/18 07:37	08/10/18 21:21	1

Lab Sample ID: LCS 490-534847/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Antimony	0.100	0.1070		mg/L		107	85 - 115
Selenium	0.100	0.09180		mg/L		92	85 - 115

Lab Sample ID: LCSD 490-534847/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Antimony	0.100	0.1037		mg/L		104	85 - 115	3	20
Selenium	0.100	0.09200		mg/L		92	85 - 115	0	20

Lab Sample ID: 490-156703-E-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Antimony	ND		0.100	0.1113		mg/L		111	70 - 130

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: 490-156703-E-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Selenium	ND		0.100	0.09510		mg/L		95	70 - 130		

Lab Sample ID: 490-156703-E-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Antimony	ND		0.100	0.1077		mg/L		108	70 - 130	3	20
Selenium	ND		0.100	0.09450		mg/L		95	70 - 130	1	20

Lab Sample ID: 490-156813-A-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Antimony	ND		0.100	0.1021		mg/L		102	70 - 130		
Selenium	ND		0.100	0.09380		mg/L		94	70 - 130		

Lab Sample ID: 490-156813-A-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 535380 — **Prep Batch: 534847**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Antimony	ND		0.100	0.09930		mg/L		99	70 - 130	3	20
Selenium	ND		0.100	0.09150		mg/L		92	70 - 130	2	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-534597/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		08/08/18 09:56	08/08/18 21:21	1

Lab Sample ID: LCS 490-534597/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Phosphorus, Total			2.00	1.880		mg/L		94	90 - 110		

Lab Sample ID: LCSD 490-534597/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total			2.00	1.880		mg/L		94	90 - 110	0	20

Method: 365.4 - Phosphorus, Total (Continued)

Lab Sample ID: 490-156790-A-1-E MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Phosphorus, Total	3.88		2.00	5.830		mg/L		98	73 - 119		

Lab Sample ID: 490-156790-A-1-F MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534825 — **Prep Batch: 534597**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	3.88		2.00	5.570		mg/L		85	73 - 119	5	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-534146/37 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			08/03/18 21:17	1
Alkalinity	ND		10.0	5.00	mg/L			08/03/18 21:17	1

Lab Sample ID: LCS 490-534146/38 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Alkalinity			100	96.13		mg/L		96	90 - 110		

Lab Sample ID: LCSD 490-534146/46 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity			100	99.81		mg/L		100	90 - 110	4	20

Lab Sample ID: 490-156744-I-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 534146

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	481			481.9		mg/L				0.2	20
Alkalinity	481			481.9		mg/L				0.2	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-533354/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			08/02/18 16:00	1

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Lab Sample ID: LCS 490-533354/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Dissolved Solids			100	100.0		mg/L		100	90 - 110		

Lab Sample ID: LCSD 490-533354/3 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Dissolved Solids			100	105.0		mg/L		105	90 - 110	5	20

Lab Sample ID: 490-156658-F-2 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	5450	E		5364	E	mg/L				2	20

Lab Sample ID: 490-156724-G-2 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533354

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	86.0			84.00		mg/L				2	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-156656-G-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533505

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	7.1			7.1		SU				0	20

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: MB 490-536364/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 536364

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			08/14/18 21:32	1

Lab Sample ID: LCS 490-536364/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 536364

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Organic Carbon			10.0	10.84		mg/L		108	90 - 110		

Method: SM 5310B - Organic Carbon, Total (TOC) (Continued)

Lab Sample ID: LCSD 490-536364/7 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 536364

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon			10.0	10.82		mg/L		108	90 - 110	0	20

Lab Sample ID: 680-156080-Q-4 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 536364

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Organic Carbon	1.03		20.0	22.59		mg/L		108	74 - 134		

Lab Sample ID: 680-156080-Q-4 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 536364

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	1.03		20.0	22.33		mg/L		106	74 - 134	1	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-379989/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380608 — **Prep Batch: 379989**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	35.39	U	56.4	56.6		111	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Actinium-228	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Bismuth-212	47.28	U	111	111		194	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Bismuth-214	0.0000	U	14.3	14.3		54.6	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-210	-101.8	U	145	147		261	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-212	-18.83	U	13.1	13.4		38.1	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Lead-214	-16.07	U	21.4	21.4		40.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Potassium-40	-81.36	U	151	151		231	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Protactinium-231	0.0000	U	116	116		753	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Radium-226	-134.5	U G	196	197	125	351	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Radium-228	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thallium-208	0.9123	U	11.3	11.3		15.6	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thorium-232	4.271	U	6.62	6.64		62.3	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Thorium-234	-41.42	U	137	137		237	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Uranium-235	-23.09	U	63.4	63.5		116	pCi/L	08/02/18 16:27	08/04/18 21:04	1
Uranium-238	-41.42	U	137	137		237	pCi/L	08/02/18 16:27	08/04/18 21:04	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*08/02/18 16:27*	*08/04/18 21:04*	*1*

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: LCS 160-379989/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380601 — **Prep Batch: 379989**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Americium-241	136000	133600		15400		526	pCi/L	98	90 - 111
Cesium-137	45500	43580		4380		163	pCi/L	96	90 - 111
Cobalt-60	32800	31570		3130		100	pCi/L	96	89 - 110

Lab Sample ID: 490-156682-O-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 380628 — **Prep Batch: 379989**

Analyte	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Actinium-227	27.8	U	-53.30	U	127		213	pCi/L	0.43	1
Actinium-228	122		133.8		57.1		49.7	pCi/L	0.13	1
Bismuth-212	69.5	U	67.44	U	115		196	pCi/L	0.01	1
Bismuth-214	214		163.0		39.6		32.0	pCi/L	0.65	1
Lead-210	101	U	195.8	U	181		234	pCi/L	0.28	1
Lead-212	55.0		53.54		19.6		23.8	pCi/L	0.04	1
Lead-214	194		144.8		35.6		31.0	pCi/L	0.72	1
Potassium-40	74.9	U	-36.11	U	239		291	pCi/L	0.27	1
Protactinium-231	132	U	-215.8	U	702		1180	pCi/L	0.32	1
Radium-226	471	G	-221.4	U G	497	125	480	pCi/L	0.94	1
Radium-228	122		133.8		57.1		49.7	pCi/L	0.13	1
Thallium-208	15.8		16.48	U	14.3		23.4	pCi/L	0.03	1
Thorium-232	122		133.8		57.1		49.7	pCi/L	0.13	1
Thorium-234	40.8	U	35.69	U	291		487	pCi/L	0.01	1
Uranium-235	-22.1	U	9.942	U	37.4		228	pCi/L	0.46	1
Uranium-238	40.8	U	35.69	U	291		487	pCi/L	0.01	1

Other Detected Radionuclides	*Sample Result*	*Sample Qual*	*DU Result*	*DU Qual*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*RER*	*RER Limit*
Other Detected Radionuclide	*None*		*None*					*pCi/L*		

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-381190/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.9739		0.586	0.596	3.00	0.780	pCi/L	08/08/18 17:38	08/10/18 08:12	1
Gross Beta	0.08253	U	0.530	0.530	4.00	0.912	pCi/L	08/08/18 17:38	08/10/18 08:12	1

Method: 9310 - Gross Alpha / Beta (GFPC) (Continued)

Lab Sample ID: LCS 160-381190/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Alpha	51.0	38.76		5.76	3.00	1.36	pCi/L	76	73 - 133

Lab Sample ID: LCSB 160-381190/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Beta	88.0	84.66		8.99	4.00	0.939	pCi/L	96	75 - 125

Lab Sample ID: 180-79813-H-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Alpha	88.1	G	637	545.3		85.5	3.00	22.5	pCi/L	72	60 - 140

Lab Sample ID: 180-79813-H-1-C MSBT — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Beta	28.5	G	1100	1116	G	118	4.00	13.0	pCi/L	99	60 - 140

Lab Sample ID: 180-79813-H-1-D DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 381569 — **Prep Batch: 381190**

Analyte	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Gross Alpha	88.1	G	64.27	G	23.8	3.00	24.4	pCi/L	0.47	1
Gross Beta	28.5	G	31.93	G	10.4	4.00	12.2	pCi/L	0.16	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

GC/MS VOA

Analysis Batch: 533001

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	8260B	
MB 490-533001/8	Method Blank	Total/NA	Water	8260B	
LCS 490-533001/5	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-533001/6	Lab Control Sample Dup	Total/NA	Water	8260B	
490-156591-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-156591-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

Analysis Batch: 533312

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-2	Trip Blank	Total/NA	Water	8260B	
MB 490-533312/7	Method Blank	Total/NA	Water	8260B	
LCS 490-533312/4	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-533312/5	Lab Control Sample Dup	Total/NA	Water	8260B	
490-156656-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-156656-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 533562

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	OK GRO	
MB 490-533562/6	Method Blank	Total/NA	Water	OK GRO	
LCS 490-533562/5	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-533562/11	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 533551

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	3510C	
MB 490-533551/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-533551/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-533551/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 533965

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	OK DRO	533551
MB 490-533551/1-A	Method Blank	Total/NA	Water	OK DRO	533551
LCS 490-533551/2-A	Lab Control Sample	Total/NA	Water	OK DRO	533551
LCSD 490-533551/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	533551

HPLC/IC

Analysis Batch: 533801

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	300.0	
490-156688-1	Woods Co	Total/NA	Water	300.0	
MB 490-533801/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533801/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533801/5	Lab Control Sample Dup	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 533801 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156768-E-2 MS	Matrix Spike	Total/NA	Water	300.0	

Analysis Batch: 533802

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	300.0	
MB 490-533802/3	Method Blank	Total/NA	Water	300.0	
LCS 490-533802/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-533802/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-156768-E-2 MS	Matrix Spike	Total/NA	Water	300.0	

Metals

Prep Batch: 533242

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	200.7	
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	

Analysis Batch: 533865

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	200.7 Rev 4.4	533242
MB 490-533242/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	533242
LCS 490-533242/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	533242
LCSD 490-533242/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 534014

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	200.7 Rev 4.4	533242

Analysis Batch: 534542

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	200.7 Rev 4.4	533242

Prep Batch: 534847

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	200.7	
MB 490-534847/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-534847/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-534847/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	
490-156703-E-1-B MS	Matrix Spike	Total/NA	Water	200.7	
490-156703-E-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	
490-156813-A-1-B MS	Matrix Spike	Total/NA	Water	200.7	
490-156813-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	

Analysis Batch: 535380

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-534847/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	534847
LCS 490-534847/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	534847
LCSD 490-534847/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	534847

Metals (Continued)

Analysis Batch: 535380 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156703-E-1-B MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	534847
490-156703-E-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	534847
490-156813-A-1-B MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	534847
490-156813-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	534847

Analysis Batch: 536005

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	SM 2340B	

Analysis Batch: 536308

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	200.7 Rev 4.4	534847

General Chemistry

Analysis Batch: 533354

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	SM 2540C	
MB 490-533354/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-533354/2	Lab Control Sample	Total/NA	Water	SM 2540C	
LCSD 490-533354/3	Lab Control Sample Dup	Total/NA	Water	SM 2540C	
490-156658-F-2 DU	Duplicate	Total/NA	Water	SM 2540C	
490-156724-G-2 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 533505

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	SM 4500 H+ B	
LCS 490-533505/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-156656-G-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 534146

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	SM 2320B	
MB 490-534146/37	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-534146/38	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-534146/46	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-156744-I-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Prep Batch: 534597

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	365.2/365.3/365	
MB 490-534597/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-534597/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-534597/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-156790-A-1-E MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-156790-A-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 534825

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	365.4	534597

General Chemistry (Continued)

Analysis Batch: 534825 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-534597/1-A	Method Blank	Total/NA	Water	365.4	534597
LCS 490-534597/2-A	Lab Control Sample	Total/NA	Water	365.4	534597
LCSD 490-534597/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	534597
490-156790-A-1-E MS	Matrix Spike	Total/NA	Water	365.4	534597
490-156790-A-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	534597

Analysis Batch: 536364

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	SM 5310B	
MB 490-536364/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-536364/6	Lab Control Sample	Total/NA	Water	SM 5310B	
LCSD 490-536364/7	Lab Control Sample Dup	Total/NA	Water	SM 5310B	
680-156080-Q-4 MS	Matrix Spike	Total/NA	Water	SM 5310B	
680-156080-Q-4 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

Rad

Prep Batch: 379989

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	Fill_Geo-0	
MB 160-379989/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-379989/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
490-156682-O-1-B DU	Duplicate	Total/NA	Water	Fill_Geo-0	

Prep Batch: 381190

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-156688-1	Woods Co	Total/NA	Water	Evaporation	
MB 160-381190/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-381190/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-381190/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
180-79813-H-1-B MS	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-C MSBT	Matrix Spike	Total/NA	Water	Evaporation	
180-79813-H-1-D DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Client Sample ID: Woods Co

Lab Sample ID: 490-156688-1
Date Collected: 07/31/18 10:30
Matrix: Water
Date Received: 08/01/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		5	10 mL	10 mL	533001	08/01/18 23:10	P1B	TAL NSH
Total/NA	Analysis	OK GRO		1	5 mL	5 mL	533562	08/03/18 13:54	S1S	TAL NSH
Total/NA	Prep	3510C			1121.9 mL	1 mL	533551	08/03/18 06:18	CC	TAL NSH
Total/NA	Analysis	OK DRO		100			533965	08/06/18 15:50	PRB	TAL NSH
Total/NA	Analysis	300.0		50			533801	08/03/18 13:29	SW1	TAL NSH
Total/NA	Analysis	300.0		50			533802	08/03/18 13:29	SW1	TAL NSH
Total/NA	Analysis	300.0		5000			533801	08/03/18 13:48	SW1	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	534847	08/09/18 07:38	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			536308	08/15/18 11:41	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		5			533865	08/03/18 18:04	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		50			534014	08/04/18 17:23	RDH	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	533242	08/02/18 07:52	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		200			534542	08/07/18 17:40	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			536005	08/14/18 16:05	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	534597	08/08/18 09:56	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	534825	08/08/18 21:37	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	534146	08/03/18 21:45	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	533354	08/02/18 16:00	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			533505	08/02/18 17:11	JDG	TAL NSH
Total/NA	Analysis	SM 5310B		2	50 mL	50 mL	536364	08/14/18 21:32	VRP	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	379989	08/02/18 16:27	EAW	TAL SL
Total/NA	Analysis	901.1		1			380601	08/04/18 22:18	CDR	TAL SL
Total/NA	Prep	Evaporation			0.5 mL	1.0 g	381190	08/08/18 17:38	MRB	TAL SL
Total/NA	Analysis	9310		1			381569	08/10/18 08:14	RTM	TAL SL

Client Sample ID: Trip Blank

Lab Sample ID: 490-156688-2
Date Collected: 07/31/18 10:30
Matrix: Water
Date Received: 08/01/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	10 mL	10 mL	533312	08/02/18 14:44	RP	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-18 *
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-18
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-18 *
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-18
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-156688-1
SDG: Woods Co Meramec

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-18 *
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-18 *
Nevada	State Program	9	MO000542018-1	07-31-18 *
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-18 *
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-18 *
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-18 *
West Virginia DEP	State Program	3	381	08-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-156688 Chain of Custody

Cooler Received/Opened On____08-01-2018_@__10:00_____

Time Samples Removed From Cooler 13:58 Time Samples Placed In Storage 14:06 (2 Hour Window)

1. Tracking # 8147 (last 4 digits, FedEx) Courier: _FedEx_

   IR Gun ID___14740456_____ pH Strip Lot HC849161 Chlorine Strip Lot 111417F

2. Temperature of rep. sample or temp blank when opened: 1.5 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 (front) + 1 (back)

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) KD

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry Ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #_____

I certify that I unloaded the cooler and answered questions 7-14 (intial) KD

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) KD

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) KD

I certify that I attached a label with the unique LIMS number to each container (intial) KD

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment
Cooler Receipt Form.doc

LF-1
End of Form

Revised 8/23/17

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information

Client Contact: Dr. James Rosenblum
Company: CH2M Hill, Inc.
Address: 12377 Merit Drive Suite 1000
City: Dallas
State, Zip: TX, 75251
Phone: 248-939-3216(Tel)
Email: james.rosenblum@ch2m.com
Project Name: OWRB Study Phase II
Site: Woods Co Meremac

Sampler: Jared Mays
Phone: 580 541 0319

Due Date Requested:
TAT Requested (days):
PO #:
WO #:
Project #: 49013620
SSOW#:

Lab PM: Gambill, Jennifer
E-Mail: jennifer.gambill@testamericainc.com

Carrier Tracking No(s):

COC No:
Page: Page of
Job #:

Analysis Requested

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	7/31	1030 AM	G	W																	
Gross Alpha/Beta (1)	7/31	1030 AM	G	W																	
Alk/IC/pH (3)	7/31	1030 AM	G	W																	
Metals/Hardness (1)	7/31	1030 AM	G	W																	
TOC (1)	7/31	1030 AM	G	W																	
BTEX/GRO (6)	7/31	1030 AM	G	W																	
TDS (1)	7/31	1030 AM	G	W																	
DRO (2)	7/31	1030 AM	G	W																	
phosphorus (1)	7/31	1030 AM	G	W																	
			G	W																	

Preservation Codes:

A - HCL
B - NaOH
C - Zn Acetate
D - Nitric Acid
E - NaHSO4
F - MeOH
G - Amchlor
H - Ascorbic Acid
I - Ice
J - DI Water
K - EDTA
L - EDA
M - Hexane
N - None
O - AsNaO2
P - Na2O4S
Q - Na2SO3
R - Na2S2O3
S - H2SO4
T - TSP Dodecahydrate
U - Acetone
V - MCAA
W - pH 4-5
Z - other (specify)

Other:

Loc: 490
156688

Possible Hazard Identification
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return To Client ☐ Disposal By Lab ☐ Archive For _____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: Jacob Hernandez OWRB Date: Time: 1:00 pm Method of Shipment: Hand delivered

Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company
	7/31/18	OEB	Fed Ex		
Relinquished by:	Date/Time:	Company	Received by:	08-01-2018 10:00	TA-NAS
Relinquished by:	Date/Time:	Company	Received by:	Date/Time:	Company

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 1.5

Ver: 08/04/2016

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-158404-1
TestAmerica SDG: Alfalfa County Mississippi Line
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Dr. James Rosenblum

Jennifer Gambill

Authorized for release by:
9/20/2018 12:57:19 PM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-158404-1	Alfalfa County Mississippi Line	Water	08/30/18 12:30	08/31/18 10:00

Job ID: 490-158404-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-158404-1

Comments
No additional comments.

Receipt
The sample was received on 8/31/2018 10:00 AM; the sample arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 5.6º C.

GC/MS VOA
Method(s) 8260B: Surrogate recovery for the following sample was outside control limits: Alfalfa County Mississippi Line (490-158404-1). Evidence of matrix interference is present; therefore, re-extraction and/or re-analysis was not performed.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

HPLC/IC
Method(s) 300.0: The method blank for analytical batch 490-540172 contained Bromide above the method detection limit. This target analyte concentration was less than half the reporting limit (1/2RL); therefore, re-extraction and re-analysis of samples was not performed.

Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Alfalfa County Mississippi Line (490-158404-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: Due to the nature of the sample matrix, a matrix spike / matrix spike duplicate (MS/MSD) was not analyzed with 490-540172. However, the laboratory control sample / laboratory control sample duplicate (LCS/LCSD) recoveries were within the acceptance limits.

Method(s) 300.0: The continuing calibration verification (CCV) associated with batch 490-540173 recovered above the upper control limit for Nitrate as N and Nitrite as N. The following sample associated with this CCV was non-detect for the affected analytes; therefore, the data have been reported: (CCV 490-540173/14).

Method(s) 300.0: Due to the nature of the sample matrix, a matrix spike / matrix spike duplicate (MS/MSD) was not analyzed with 490-540173. However, the laboratory control sample / laboratory control sample duplicate (LCS/LCSD) recoveries were within the acceptance limits.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC VOA
Method(s) OK GRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate/sample duplicate (MS/MSD/DUP) associated with analytical batch 490-540861.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-540779 and analytical batch 490-540986.

Method(s) OK DRO: The following sample was diluted to bring the concentration of target analytes within the calibration range: Alfalfa County Mississippi Line (490-158404-1). Elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

General Chemistry
Method(s) 365.4: The matrix spike (MS) recovery for preparation batch 490-540980 and analytical batch 490-541324 was outside control limits. Non-homogeneity is suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Job ID: 490-158404-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD

Method(s) 901.1: Gamma Prep Batch 160-387783: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Alfalfa County Mississippi Line (490-158404-1), (LCS 160-387783/2-A), (MB 160-387783/1-A) and (490-158404-O-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-387783: The following sample exhibited a negative result greater in magnitude than the 3 sigma TPU: Alfalfa County Mississippi Line (490-158404-1). This occurrence was evaluated and determined to be random in nature. Sporadic occurrences such as this are statistically expected. No further action is required.

Method(s) 901.1: Gamma Prep Batch 160-384024: The relative percent difference (RPD) and replicate error ratio (RER) is outside of the acceptance limits of 40%/1 for the following samples: Alfalfa County Mississippi Line (490-158404-1) and (490-158404-O-1-B DU). Both the sample and duplicate activity are less than the minimum detectable concentration (MDC). The data have been reported with this narrative.

Method(s) 901.1: Gamma Prep Batch 160-387783: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative. Alfalfa County Mississippi Line (490-158404-1) and (490-158404-O-1-B DU).

Method(s) 9310: Gross Alpha/Beta Prep Batch 160-388469: The gross alpha and gross beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Alfalfa County Mississippi Line (490-158404-1), (160-30465-A-3-B) and (160-30465-A-3-C DU). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Definitions/Glossary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Qualifiers

GC/MS VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

HPLC/IC

Qualifier	Qualifier Description
B	Compound was found in the blank and sample.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

Metals

Qualifier	Qualifier Description
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

General Chemistry

Qualifier	Qualifier Description
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.
F1	MS and/or MSD Recovery is outside acceptance limits.
F2	MS/MSD RPD exceeds control limits

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.
F	Duplicate RPD exceeds the control limit

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Client Sample ID: Alfalfa County Mississippi Line

Lab Sample ID: 490-158404-1

Date Collected: 08/30/18 12:30
Date Received: 08/31/18 10:00

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	**432**		10.0	2.00	ug/L			08/31/18 15:55	10
Ethylbenzene	**5.89**		1.00	0.190	ug/L			08/31/18 15:02	1
Toluene	**165**		1.00	0.170	ug/L			08/31/18 15:02	1
Xylenes, Total	**21.5**		3.00	0.580	ug/L			08/31/18 15:02	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*131*	*X*	*70 - 130*		*08/31/18 15:02*	*1*
1,2-Dichloroethane-d4 (Surr)	*112*		*70 - 130*		*08/31/18 15:55*	*10*
4-Bromofluorobenzene (Surr)	*118*		*70 - 130*		*08/31/18 15:02*	*1*
4-Bromofluorobenzene (Surr)	*110*		*70 - 130*		*08/31/18 15:55*	*10*
Dibromofluoromethane (Surr)	*102*		*70 - 130*		*08/31/18 15:02*	*1*
Dibromofluoromethane (Surr)	*99*		*70 - 130*		*08/31/18 15:55*	*10*
Toluene-d8 (Surr)	*97*		*70 - 130*		*08/31/18 15:02*	*1*
Toluene-d8 (Surr)	*95*		*70 - 130*		*08/31/18 15:55*	*10*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	**4500**		100	50.0	ug/L			09/06/18 10:34	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*82*		*70 - 130*		*09/06/18 10:34*	*5*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	**1650**		430	215	ug/L		09/05/18 15:04	09/06/18 17:56	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*90*		*50 - 150*	*09/05/18 15:04*	*09/06/18 17:56*	*5*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	**2860**	**B**	200	10.0	mg/L			08/31/18 19:33	200
Nitrate as N	ND		20.0	10.0	mg/L			08/31/18 19:33	200
Chloride	**191000**		10000	7000	mg/L			09/10/18 19:08	10000
Nitrite as N	ND		20.0	10.0	mg/L			08/31/18 19:33	200
Fluoride	**14.8**		5.00	3.00	mg/L			08/31/18 19:19	50
Sulfate	**348**		50.0	30.0	mg/L			08/31/18 19:19	50

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 20:41	1
Antimony	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Arsenic	ND		0.100	0.0860	mg/L		09/01/18 09:59	09/08/18 20:58	10
Barium	**5.59**		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Beryllium	ND		0.00400	0.00200	mg/L		09/01/18 09:59	09/07/18 20:41	1
Cadmium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Calcium	**9300**		10.0	5.00	mg/L		09/01/18 09:59	09/08/18 20:58	10
Chromium	ND		0.0500	0.0300	mg/L		09/01/18 09:59	09/08/18 20:58	10
Cobalt	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Copper	**0.00960**	**J**	0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 20:41	1
Iron	**14.4**		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 20:41	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Client Sample ID: Alfalfa County Mississippi Line

Lab Sample ID: 490-158404-1
Date Collected: 08/30/18 12:30
Matrix: Water
Date Received: 08/31/18 10:00

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Lead	**0.0800**		0.0500	0.0200	mg/L		09/01/18 09:59	09/08/18 20:58	10
Magnesium	**2170**		10.0	2.50	mg/L		09/01/18 09:59	09/08/18 20:58	10
Manganese	**4.10**		0.150	0.0500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Nickel	ND		0.100	0.0300	mg/L		09/01/18 09:59	09/08/18 20:58	10
Potassium	**509**		1.00	0.500	mg/L		09/01/18 09:59	09/08/18 20:52	1
Selenium	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Silver	ND		0.0500	0.0300	mg/L		09/01/18 09:59	09/08/18 20:58	10
Sodium	**36900**		100	40.0	mg/L		09/01/18 09:59	09/10/18 19:41	100
Thallium	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:58	10
Vanadium	ND		0.0200	0.0100	mg/L		09/01/18 09:59	09/07/18 20:41	1
Zinc	ND		0.500	0.250	mg/L		09/01/18 09:59	09/08/18 20:58	10

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**32100**		10.0	5.00	mg/L			09/17/18 13:21	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/06/18 10:55	09/07/18 08:41	1
Bicarbonate Alkalinity as CaCO3	**40.0**		10.0	5.00	mg/L			09/06/18 13:58	1
Alkalinity	**40.0**		10.0	5.00	mg/L			09/06/18 13:58	1
Total Dissolved Solids	**174000**		1000	700	mg/L			09/01/18 18:40	1
pH	**6.0**	**HF**	0.1	0.1	SU			08/31/18 18:07	1
Total Organic Carbon	**34.4**	**F1 F2**	1.00	0.500	mg/L			09/04/18 06:07	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	-16.2	U	54.7	54.7		165	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Actinium-228	**61.3**		37.8	38.3		37.4	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Bismuth-212	-15.6	U	189	189		341	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Bismuth-214	**49.9**		24.6	25.1		29.9	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Lead-210	65.2	U	162	163		236	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Lead-212	-8.25	U	20.8	20.8		45.4	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Lead-214	**69.2**		25.3	26.3		31.7	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Potassium-40	196	U	191	192		234	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Protactinium-231	104	U	368	368		837	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Radium-226	0.000	U G	335	335	125	549	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Radium-228	**61.3**		37.8	38.3		37.4	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Thallium-208	8.34	U	14.9	14.9		20.4	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Thorium-232	**61.3**		37.8	38.3		37.4	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Thorium-234	-241	U	138	141		531	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Uranium-235	29.8	U	62.0	62.0		122	pCi/L	09/07/18 09:32	09/07/18 14:28	1
Uranium-238	-241	U	138	141		531	pCi/L	09/07/18 09:32	09/07/18 14:28	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/07/18 09:32*	*09/07/18 14:28*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Client Sample ID: Alfalfa County Mississippi Line

Lab Sample ID: 490-158404-1

Date Collected: 08/30/18 12:30
Matrix: Water
Date Received: 08/31/18 10:00

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	1600	U G	1520	1530	3.00	2310	pCi/L	09/11/18 10:38	09/12/18 10:51	1
Gross Beta	747	U G	1120	1120	4.00	1840	pCi/L	09/11/18 10:38	09/12/18 10:51	1

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-540000/6
Matrix: Water
Analysis Batch: 540000

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/31/18 12:38	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/31/18 12:38	1
Toluene	ND		1.00	0.170	ug/L			08/31/18 12:38	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/31/18 12:38	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*114*		*70 - 130*		*08/31/18 12:38*	*1*
4-Bromofluorobenzene (Surr)	*113*		*70 - 130*		*08/31/18 12:38*	*1*
Dibromofluoromethane (Surr)	*103*		*70 - 130*		*08/31/18 12:38*	*1*
Toluene-d8 (Surr)	*100*		*70 - 130*		*08/31/18 12:38*	*1*

Lab Sample ID: LCS 490-540000/3
Matrix: Water
Analysis Batch: 540000

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	22.56		ug/L		113	70 - 130
Ethylbenzene	20.0	23.68		ug/L		118	70 - 130
Toluene	20.0	20.43		ug/L		102	70 - 130
Xylenes, Total	40.0	47.67		ug/L		119	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*115*		*70 - 130*
4-Bromofluorobenzene (Surr)	*113*		*70 - 130*
Dibromofluoromethane (Surr)	*98*		*70 - 130*
Toluene-d8 (Surr)	*91*		*70 - 130*

Lab Sample ID: 490-158454-B-1 MS
Matrix: Water
Analysis Batch: 540000

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	22.06		ug/L		110	55 - 147
Ethylbenzene	ND		20.0	23.55		ug/L		118	65 - 139
Toluene	ND		20.0	21.73		ug/L		109	64 - 136
Xylenes, Total	ND		40.0	49.08		ug/L		123	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*115*		*70 - 130*
4-Bromofluorobenzene (Surr)	*116*		*70 - 130*
Dibromofluoromethane (Surr)	*98*		*70 - 130*
Toluene-d8 (Surr)	*101*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-158454-C-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540000

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	22.57		ug/L		113	55 - 147	2	22
Ethylbenzene	ND		20.0	24.77		ug/L		124	65 - 139	5	18
Toluene	ND		20.0	22.54		ug/L		113	64 - 136	4	18
Xylenes, Total	ND		40.0	50.31		ug/L		126	69 - 132	2	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*
4-Bromofluorobenzene (Surr)	*114*		*70 - 130*
Dibromofluoromethane (Surr)	*99*		*70 - 130*
Toluene-d8 (Surr)	*100*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-540861/5 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540861

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			09/06/18 08:41	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*102*		*70 - 130*		*09/06/18 08:41*	*1*

Lab Sample ID: LCS 490-540861/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540861

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
C6-C10 OK			200	200.7		ug/L		100	80 - 120		

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*102*		*70 - 130*

Lab Sample ID: LCSD 490-540861/36 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540861

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK			200	219.0		ug/L		110	80 - 120	9	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*104*		*70 - 130*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-540779/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540986 — **Prep Batch: 540779**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		09/05/18 15:03	09/06/18 13:33	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*85*		*50 - 150*	*09/05/18 15:03*	*09/06/18 13:33*	*1*

Lab Sample ID: LCS 490-540779/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540986 — **Prep Batch: 540779**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	443.6		ug/L		89	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*92*		*50 - 150*

Lab Sample ID: LCSD 490-540779/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540986 — **Prep Batch: 540779**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	470.1		ug/L		94	80 - 120	6	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*95*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-540172/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540172

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	0.3487	J	1.00	0.0500	mg/L			08/31/18 18:05	1
Chloride	ND		1.00	0.700	mg/L			08/31/18 18:05	1
Fluoride	ND		0.100	0.0600	mg/L			08/31/18 18:05	1
Sulfate	ND		1.00	0.600	mg/L			08/31/18 18:05	1

Lab Sample ID: LCS 490-540172/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540172

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.794		mg/L		98	90 - 110
Chloride	10.0	9.411		mg/L		94	90 - 110
Fluoride	1.00	1.036		mg/L		103	90 - 110
Sulfate	10.0	10.74		mg/L		107	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-540172/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540172

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.839		mg/L		98	90 - 110	0	20
Chloride	10.0	9.478		mg/L		95	90 - 110	1	20
Fluoride	1.00	1.048		mg/L		105	90 - 110	1	20
Sulfate	10.0	10.79		mg/L		108	90 - 110	0	20

Lab Sample ID: MB 490-540173/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540173

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			08/31/18 18:05	1
Nitrite as N	ND		0.100	0.0500	mg/L			08/31/18 18:05	1

Lab Sample ID: LCS 490-540173/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540173

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	0.9717		mg/L		97	90 - 110
Nitrite as N	1.00	1.059		mg/L		106	90 - 110

Lab Sample ID: LCSD 490-540173/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540173

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	0.9838		mg/L		98	90 - 110	1	20
Nitrite as N	1.00	1.055		mg/L		105	90 - 110	0	20

Lab Sample ID: MB 490-541752/29 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			09/10/18 18:33	1
Chloride	ND		1.00	0.700	mg/L			09/10/18 18:33	1
Fluoride	ND		0.100	0.0600	mg/L			09/10/18 18:33	1
Sulfate	ND		1.00	0.600	mg/L			09/10/18 18:33	1

Lab Sample ID: MB 490-541752/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			09/10/18 13:27	1
Chloride	ND		1.00	0.700	mg/L			09/10/18 13:27	1
Fluoride	ND		0.100	0.0600	mg/L			09/10/18 13:27	1
Sulfate	ND		1.00	0.600	mg/L			09/10/18 13:27	1

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCS 490-541752/30 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.564		mg/L		95	90 - 110
Chloride	10.0	10.00		mg/L		100	90 - 110
Fluoride	1.00	0.9974		mg/L		100	90 - 110
Sulfate	10.0	9.754		mg/L		97	90 - 110

Lab Sample ID: LCS 490-541752/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.539		mg/L		95	90 - 110
Chloride	10.0	9.959		mg/L		99	90 - 110
Fluoride	1.00	0.9868		mg/L		99	90 - 110
Sulfate	10.0	9.879		mg/L		99	90 - 110

Lab Sample ID: LCSD 490-541752/31 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.574		mg/L		96	90 - 110	0	20
Chloride	10.0	10.01		mg/L		100	90 - 110	0	20
Fluoride	1.00	1.011		mg/L		101	90 - 110	1	20
Sulfate	10.0	9.913		mg/L		99	90 - 110	2	20

Lab Sample ID: LCSD 490-541752/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.524		mg/L		95	90 - 110	0	20
Chloride	10.0	9.928		mg/L		99	90 - 110	0	20
Fluoride	1.00	0.9806		mg/L		98	90 - 110	1	20
Sulfate	10.0	9.863		mg/L		98	90 - 110	0	20

Lab Sample ID: 490-158493-K-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	0.445	J	10.0	10.16		mg/L		97	80 - 120
Chloride	8.79		10.0	19.42		mg/L		106	80 - 120
Fluoride	0.101		1.00	1.078		mg/L		98	80 - 120
Sulfate	21.4		10.0	31.35		mg/L		99	80 - 120

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-540220/1-A
Matrix: Water
Analysis Batch: 541430

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 540220

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Beryllium	ND		0.00400	0.00200	mg/L		09/01/18 09:59	09/07/18 18:05	1
Copper	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Iron	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Vanadium	ND		0.0200	0.0100	mg/L		09/01/18 09:59	09/07/18 18:05	1

Lab Sample ID: MB 490-540220/1-A
Matrix: Water
Analysis Batch: 541550

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 540220

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Antimony	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Arsenic	ND		0.0100	0.00860	mg/L		09/01/18 09:59	09/08/18 19:17	1
Barium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Beryllium	ND		0.00400	0.00200	mg/L		09/01/18 09:59	09/08/18 19:17	1
Cadmium	ND		0.00100	0.000500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Calcium	ND		1.00	0.500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Cobalt	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Copper	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Iron	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Lead	ND		0.00500	0.00200	mg/L		09/01/18 09:59	09/08/18 19:17	1
Magnesium	ND		1.00	0.250	mg/L		09/01/18 09:59	09/08/18 19:17	1
Manganese	ND		0.0150	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Potassium	ND		1.00	0.500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Selenium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Silver	ND		0.00500	0.00300	mg/L		09/01/18 09:59	09/08/18 19:17	1
Sodium	ND		1.00	0.400	mg/L		09/01/18 09:59	09/08/18 19:17	1
Thallium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 19:17	1
Vanadium	ND		0.0200	0.0100	mg/L		09/01/18 09:59	09/08/18 19:17	1

Lab Sample ID: MB 490-540220/1-A
Matrix: Water
Analysis Batch: 541805

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 540220

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Sodium	ND		1.00	0.400	mg/L		09/01/18 09:59	09/10/18 19:25	1

Lab Sample ID: LCS 490-540220/24-A
Matrix: Water
Analysis Batch: 541550

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 540220

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Silver	0.0500	0.04800		mg/L		96	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-540220/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	0.9840		mg/L		98	85 - 115
Beryllium	0.100	0.1001		mg/L		100	85 - 115
Copper	0.100	0.1081		mg/L		108	85 - 115
Iron	1.00	1.003		mg/L		100	85 - 115
Vanadium	0.100	0.1042		mg/L		104	85 - 115

Lab Sample ID: LCS 490-540220/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541550 — **Prep Batch: 540220**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.038		mg/L		104	85 - 115
Antimony	0.100	0.1020		mg/L		102	85 - 115
Arsenic	0.100	0.1037		mg/L		104	85 - 115
Barium	0.100	0.1024		mg/L		102	85 - 115
Beryllium	0.100	0.1029		mg/L		103	85 - 115
Cadmium	0.100	0.1040		mg/L		104	85 - 115
Calcium	10.0	9.874		mg/L		99	85 - 115
Cobalt	0.100	0.1046		mg/L		105	85 - 115
Copper	0.100	0.09980		mg/L		100	85 - 115
Iron	1.00	0.9285		mg/L		93	85 - 115
Lead	0.100	0.1037		mg/L		104	85 - 115
Magnesium	10.0	10.41		mg/L		104	85 - 115
Manganese	0.100	0.1016		mg/L		102	85 - 115
Potassium	10.0	10.39		mg/L		104	85 - 115
Selenium	0.100	0.1148		mg/L		115	85 - 115
Sodium	10.0	9.928		mg/L		99	85 - 115
Thallium	0.100	0.1026		mg/L		103	85 - 115
Vanadium	0.100	0.1040		mg/L		104	85 - 115

Lab Sample ID: LCSD 490-540220/25-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541550 — **Prep Batch: 540220**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Silver	0.0500	0.04860		mg/L		97	85 - 115	1	20

Lab Sample ID: LCSD 490-540220/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	0.9816		mg/L		98	85 - 115	0	20
Beryllium	0.100	0.09990		mg/L		100	85 - 115	0	20
Copper	0.100	0.1091		mg/L		109	85 - 115	1	20
Iron	1.00	1.002		mg/L		100	85 - 115	0	20
Vanadium	0.100	0.1045		mg/L		105	85 - 115	0	20

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCSD 490-540220/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541550 — **Prep Batch: 540220**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	1.043		mg/L		104	85 - 115	0	20
Antimony	0.100	0.1002		mg/L		100	85 - 115	2	20
Arsenic	0.100	0.1015		mg/L		102	85 - 115	2	20
Barium	0.100	0.1024		mg/L		102	85 - 115	0	20
Beryllium	0.100	0.1033		mg/L		103	85 - 115	0	20
Cadmium	0.100	0.1043		mg/L		104	85 - 115	0	20
Calcium	10.0	9.913		mg/L		99	85 - 115	0	20
Cobalt	0.100	0.1053		mg/L		105	85 - 115	1	20
Copper	0.100	0.1036		mg/L		104	85 - 115	4	20
Iron	1.00	0.9325		mg/L		93	85 - 115	0	20
Lead	0.100	0.1034		mg/L		103	85 - 115	0	20
Magnesium	10.0	10.49		mg/L		105	85 - 115	1	20
Manganese	0.100	0.1017		mg/L		102	85 - 115	0	20
Potassium	10.0	10.46		mg/L		105	85 - 115	1	20
Selenium	0.100	0.1118		mg/L		112	85 - 115	3	20
Sodium	10.0	9.939		mg/L		99	85 - 115	0	20
Thallium	0.100	0.1037		mg/L		104	85 - 115	1	20
Vanadium	0.100	0.1062		mg/L		106	85 - 115	2	20

Lab Sample ID: 490-158268-A-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	0.120		1.00	1.077		mg/L		96	70 - 130
Beryllium	ND		0.100	0.1001		mg/L		100	70 - 130
Copper	0.0199		0.100	0.1210		mg/L		101	70 - 130
Iron	0.141		1.00	1.143		mg/L		100	70 - 130
Vanadium	ND		0.100	0.1030		mg/L		103	70 - 130

Lab Sample ID: 490-158268-A-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	0.120		1.00	0.9423		mg/L		82	70 - 130	13	20
Beryllium	ND		0.100	0.08800		mg/L		88	70 - 130	13	20
Copper	0.0199		0.100	0.1080		mg/L		88	70 - 130	11	20
Iron	0.141		1.00	1.005		mg/L		86	70 - 130	13	20
Vanadium	ND		0.100	0.09500		mg/L		95	70 - 130	8	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-540980/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/06/18 10:55	09/07/18 05:52	1

Lab Sample ID: LCS 490-540980/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	2.130		mg/L		107	90 - 110

Lab Sample ID: LCSD 490-540980/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.00	1.940		mg/L		97	90 - 110	9	20

Lab Sample ID: 490-158502-F-1-E MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	ND	F1	2.00	1.400	F1	mg/L		70	73 - 119

Lab Sample ID: 490-158502-F-1-F MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542066 — **Prep Batch: 540980**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	ND	F1	2.00	1.750		mg/L		88	73 - 119	22	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-541058/29 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			09/06/18 12:41	1
Alkalinity	ND		10.0	5.00	mg/L			09/06/18 12:41	1

Lab Sample ID: LCS 490-541058/30 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	94.76		mg/L		95	90 - 110

Method: SM 2320B - Alkalinity (Continued)

Lab Sample ID: LCSD 490-541058/46 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity			100	99.00		mg/L		99	90 - 110	4	20

Lab Sample ID: 490-158407-L-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	50.7			50.52		mg/L				0.3	20
Alkalinity	50.7			50.52		mg/L				0.3	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-538922/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 538922

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			09/01/18 18:40	1

Lab Sample ID: LCS 490-538922/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 538922

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Dissolved Solids			100	97.00		mg/L		97	90 - 110		

Lab Sample ID: 490-158146-H-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 538922

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	102			94.00		mg/L				8	20

Lab Sample ID: 490-158330-M-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 538922

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	393			398.0		mg/L				1	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-158397-H-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540195

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	7.6			7.6		SU				0	20

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: MB 490-540610/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			09/04/18 06:07	1

Lab Sample ID: LCS 490-540610/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	10.0	9.459		mg/L		95	90 - 110

Lab Sample ID: LCSD 490-540610/7 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	10.0	9.664		mg/L		97	90 - 110	2	20

Lab Sample ID: 490-158404-1 MS — **Client Sample ID: Alfalfa County Mississippi Line**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	34.4	F1 F2	20.0	40.30	F1	mg/L		30	74 - 134

Lab Sample ID: 490-158404-1 MSD — **Client Sample ID: Alfalfa County Mississippi Line**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	34.4	F1 F2	20.0	50.08	F2	mg/L		79	74 - 134	22	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-387783/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 387764 — **Prep Batch: 387783**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	38.69	U	110	110		107	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Actinium-228	2.277	U	36.4	36.4		45.9	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Bismuth-212	38.64	U	113	113		197	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Bismuth-214	-8.544	U	20.1	20.1		36.7	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Lead-210	143.5	U	154	157		205	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Lead-212	-3.859	U	18.0	18.0		31.3	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Lead-214	5.800	U	3.34	3.39		31.6	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Potassium-40	-29.40	U	125	125		184	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Protactinium-231	-0.00002294	U	342	342		590	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Radium-226	66.28	U G	158	158	125	268	pCi/L	09/07/18 09:32	09/07/18 14:30	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: MB 160-387783/1-A
Matrix: Water
Analysis Batch: 387764

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 387783

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Radium-228	2.277	U	36.4	36.4		45.9	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Thallium-208	-8.234	U	11.1	11.1		16.0	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Thorium-232	2.277	U	36.4	36.4		45.9	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Thorium-234	-102.2	U	121	122		212	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Uranium-235	24.58	U	50.0	50.0		81.0	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Uranium-238	-102.2	U	121	122		212	pCi/L	09/07/18 09:32	09/07/18 14:30	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/07/18 09:32*	*09/07/18 14:30*	*1*

Lab Sample ID: LCS 160-387783/2-A
Matrix: Water
Analysis Batch: 387765

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 387783

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Americium-241			136000	132600		15300		534	pCi/L	97	90 - 111		
Cesium-137			45400	43750		4390		160	pCi/L	96	90 - 111		
Cobalt-60			32400	31160		3090		93.7	pCi/L	96	89 - 110		

Lab Sample ID: 490-158404-1 DU
Matrix: Water
Analysis Batch: 387764

Client Sample ID: Alfalfa County Mississippi Line
Prep Type: Total/NA
Prep Batch: 387783

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Actinium-227	-16.2	U		64.74	U	127		120	pCi/L			0.44	1
Actinium-228	61.3			53.88		37.3		38.6	pCi/L			0.1	1
Bismuth-212	-15.6	U		-38.55	U	141		242	pCi/L			0.07	1
Bismuth-214	49.9			45.18		17.6		19.9	pCi/L			0.11	1
Lead-210	65.2	U		21.11	U	115		188	pCi/L			0.16	1
Lead-212	-8.25	U		-2.155	U	21.6		37.0	pCi/L			0.14	1
Lead-214	69.2			71.65		20.5		25.1	pCi/L			0.05	1
Potassium-40	196	U		370.9		145		145	pCi/L			0.52	1
Protactinium-231	104	U		0.0000	U	47.1		663	pCi/L			0.25	1
Radium-226	0.000	U G		-9.044	U G	172	125	299	pCi/L			0.02	1
Radium-228	61.3			53.88		37.3		38.6	pCi/L			0.1	1
Thallium-208	8.34	U		3.953	U	7.34		15.1	pCi/L			0.20	1
Thorium-232	61.3			53.88		37.3		38.6	pCi/L			0.1	1
Thorium-234	-241	U		86.65	U F	89.6		145	pCi/L			1.42	1
Uranium-235	29.8	U		-27.48	U	59.9		120	pCi/L			0.47	1
Uranium-238	-241	U		86.65	U F	89.6		145	pCi/L			1.42	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: 490-158404-1 DU — **Client Sample ID: Alfalfa County Mississippi Line**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 387764 — **Prep Batch: 387783**

Other Detected Radionuclides	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Other Detected Radionuclide	None			None					pCi/L				

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-388469/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.6611	U	0.553	0.558	3.00	0.831	pCi/L	09/11/18 10:38	09/12/18 10:51	1
Gross Beta	0.2506	U	0.533	0.533	4.00	0.895	pCi/L	09/11/18 10:38	09/12/18 10:51	1

Lab Sample ID: LCS 160-388469/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha			51.0	43.51		6.42	3.00	1.38	pCi/L	85	73 - 133		

Lab Sample ID: LCSB 160-388469/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte			Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta			87.8	89.78		9.52	4.00	1.19	pCi/L	102	75 - 125		

Lab Sample ID: 160-30465-A-3-D MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha	3.72	U G	291	255.0		39.6	3.00	11.5	pCi/L	86	60 - 140		

Lab Sample ID: 160-30465-A-3-E MSBT — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta	21.2	G	502	511.8	G	54.3	4.00	5.32	pCi/L	98	60 - 140		

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Method: 9310 - Gross Alpha / Beta (GFPC) (Continued)

Lab Sample ID: 160-30465-A-3-C DU
Matrix: Water
Analysis Batch: 388633

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 388469

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Gross Alpha	3.72	U G		-2.272	U G	5.97	3.00	12.5	pCi/L			0.49	1
Gross Beta	21.2	G		26.03	G	5.72	4.00	5.70	pCi/L			0.44	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

GC/MS VOA

Analysis Batch: 540000

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	8260B	
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	8260B	
MB 490-540000/6	Method Blank	Total/NA	Water	8260B	
LCS 490-540000/3	Lab Control Sample	Total/NA	Water	8260B	
490-158454-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-158454-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 540861

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	OK GRO	
MB 490-540861/5	Method Blank	Total/NA	Water	OK GRO	
LCS 490-540861/4	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-540861/36	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 540779

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	3510C	
MB 490-540779/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-540779/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-540779/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 540986

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	OK DRO	540779
MB 490-540779/1-A	Method Blank	Total/NA	Water	OK DRO	540779
LCS 490-540779/2-A	Lab Control Sample	Total/NA	Water	OK DRO	540779
LCSD 490-540779/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	540779

HPLC/IC

Analysis Batch: 540172

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	300.0	
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	300.0	
MB 490-540172/3	Method Blank	Total/NA	Water	300.0	
LCS 490-540172/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-540172/5	Lab Control Sample Dup	Total/NA	Water	300.0	

Analysis Batch: 540173

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	300.0	
MB 490-540173/3	Method Blank	Total/NA	Water	300.0	
LCS 490-540173/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-540173/5	Lab Control Sample Dup	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 541752

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	300.0	
MB 490-541752/29	Method Blank	Total/NA	Water	300.0	
MB 490-541752/3	Method Blank	Total/NA	Water	300.0	
LCS 490-541752/30	Lab Control Sample	Total/NA	Water	300.0	
LCS 490-541752/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-541752/31	Lab Control Sample Dup	Total/NA	Water	300.0	
LCSD 490-541752/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-158493-K-1 MS	Matrix Spike	Total/NA	Water	300.0	

Metals

Prep Batch: 540220

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	200.7	
MB 490-540220/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-540220/24-A	Lab Control Sample	Total/NA	Water	200.7	
LCS 490-540220/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-540220/25-A	Lab Control Sample Dup	Total/NA	Water	200.7	
LCSD 490-540220/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	
490-158268-A-1-B MS	Matrix Spike	Total/NA	Water	200.7	
490-158268-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	

Analysis Batch: 541430

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	200.7 Rev 4.4	540220
MB 490-540220/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	540220
LCS 490-540220/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	540220
LCSD 490-540220/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	540220
490-158268-A-1-B MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	540220
490-158268-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	540220

Analysis Batch: 541550

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	200.7 Rev 4.4	540220
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	200.7 Rev 4.4	540220
MB 490-540220/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	540220
LCS 490-540220/24-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	540220
LCS 490-540220/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	540220
LCSD 490-540220/25-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	540220
LCSD 490-540220/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	540220

Analysis Batch: 541805

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	200.7 Rev 4.4	540220
MB 490-540220/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	540220

Analysis Batch: 543312

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	SM 2340B	

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

General Chemistry

Analysis Batch: 538922

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	SM 2540C	
MB 490-538922/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-538922/2	Lab Control Sample	Total/NA	Water	SM 2540C	
490-158146-H-1 DU	Duplicate	Total/NA	Water	SM 2540C	
490-158330-M-1 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 540195

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	SM 4500 H+ B	
LCS 490-540195/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-158397-H-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 540610

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	SM 5310B	
MB 490-540610/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-540610/6	Lab Control Sample	Total/NA	Water	SM 5310B	
LCSD 490-540610/7	Lab Control Sample Dup	Total/NA	Water	SM 5310B	
490-158404-1 MS	Alfalfa County Mississippi Line	Total/NA	Water	SM 5310B	
490-158404-1 MSD	Alfalfa County Mississippi Line	Total/NA	Water	SM 5310B	

Prep Batch: 540980

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	365.2/365.3/365	
MB 490-540980/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-540980/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-540980/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-158502-F-1-E MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-158502-F-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 541058

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	SM 2320B	
MB 490-541058/29	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-541058/30	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-541058/46	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-158407-L-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Analysis Batch: 541324

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	365.4	540980
MB 490-540980/1-A	Method Blank	Total/NA	Water	365.4	540980
LCS 490-540980/2-A	Lab Control Sample	Total/NA	Water	365.4	540980
LCSD 490-540980/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	540980
490-158502-F-1-E MS	Matrix Spike	Total/NA	Water	365.4	540980

Analysis Batch: 542066

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158502-F-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	540980

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Rad

Prep Batch: 387783

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	Fill_Geo-0	
MB 160-387783/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-387783/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
490-158404-1 DU	Alfalfa County Mississippi Line	Total/NA	Water	Fill_Geo-0	

Prep Batch: 388469

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158404-1	Alfalfa County Mississippi Line	Total/NA	Water	Evaporation	
MB 160-388469/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-388469/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-388469/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
160-30465-A-3-D MS	Matrix Spike	Total/NA	Water	Evaporation	
160-30465-A-3-E MSBT	Matrix Spike	Total/NA	Water	Evaporation	
160-30465-A-3-C DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Client Sample ID: Alfalfa County Mississippi Line

Lab Sample ID: 490-158404-1

Date Collected: 08/30/18 12:30

Matrix: Water

Date Received: 08/31/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	5 mL	5 mL	540000	08/31/18 15:02	P1B	TAL NSH
Total/NA	Analysis	8260B		10	5 mL	5 mL	540000	08/31/18 15:55	P1B	TAL NSH
Total/NA	Analysis	OK GRO		5	5 mL	5 mL	540861	09/06/18 10:34	S1S	TAL NSH
Total/NA	Prep	3510C			1163.5 mL	1 mL	540779	09/05/18 15:04	KWS	TAL NSH
Total/NA	Analysis	OK DRO		5			540986	09/06/18 17:56	GMH	TAL NSH
Total/NA	Analysis	300.0		50			540172	08/31/18 19:19	SW1	TAL NSH
Total/NA	Analysis	300.0		200			540172	08/31/18 19:33	SW1	TAL NSH
Total/NA	Analysis	300.0		200			540173	08/31/18 19:33	SW1	TAL NSH
Total/NA	Analysis	300.0		10000			541752	09/10/18 19:08	JHS	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			541430	09/07/18 20:41	LDC	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			541550	09/08/18 20:52	LDC	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		10			541550	09/08/18 20:58	LDC	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		100			541805	09/10/18 19:41	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			543312	09/17/18 13:21	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	540980	09/06/18 10:55	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	541324	09/07/18 08:41	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	541058	09/06/18 13:58	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	538922	09/01/18 18:40	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			540195	08/31/18 18:07	JDG	TAL NSH
Total/NA	Analysis	SM 5310B		1	50 mL	50 mL	540610	09/04/18 06:07	CLJ	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	387783	09/07/18 09:32	PK	TAL SL
Total/NA	Analysis	901.1		1			387765	09/07/18 14:28	KLS	TAL SL
Total/NA	Prep	Evaporation			0.1 mL	1.0 g	388469	09/11/18 10:38	SCB	TAL SL
Total/NA	Analysis	9310		1			388633	09/12/18 10:51	CDR	TAL SL

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-19
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-19
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-19
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-19
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158404-1
SDG: Alfalfa County Mississippi Line

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-19
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-19
Nevada	State Program	9	MO000542018-1	07-31-19
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-19
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-19
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-18 *
West Virginia DEP	State Program	3	381	10-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-158404 Chain of Custody

Cooler Received/Opened On 8/31/2018 @ 1000

Time Samples Removed From Cooler_____ Time Samples Placed In Storage_____ (2 Hour Window)

1. Tracking # 8170 (last 4 digits, FedEx) Courier: FedEx

   IR Gun ID 14740456 pH Strip Lot_____ Chlorine Strip Lot_____

2. Temperature of rep. sample or temp blank when opened: 5.6 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 (front)

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) KD

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence # NA

I certify that I unloaded the cooler and answered questions 7-14 (intial) EA

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) EA

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) EA

I certify that I attached a label with the unique LIMS number to each container (intial) EA

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information

Client Contact: Dr. James Rosenblum
Company: CH2M Hill, Inc
Address: 12377 Merit Drive Suite 1000
City: Dallas
State, Zip: TX, 75251
Phone: 248-939-3216(Tel)
Email: james.rosenblum@ch2m.com
Project Name: OWRB Study Phase II
Site:

Sampler: Jarrod Maly
Phone: 580 541 0319

Due Date Requested:
TAT Requested (days):
PO #:
WO #
Project #: 49013620
SSOW#:

Lab PM: Gambill, Jennifer
E-Mail: jennifer.gambill@testamericainc.com

Carrier Tracking No(s):

COC No:
Page: Page of
Job #:

Loc: 490
158404

Alfalfa County Mississippi Line

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	8/30	12:30	G	W																	
Gross Alpha/Beta (1)	8/30	12:30	G	W																	
Alk/IC/pH (3)	8/30	12:30	G	W																	
Metals/Hardness (1)	8/30	12:30	G	W																	
TOC (1)	8/30	12:30	G	W																	
BTEX/GRO (6)	8/30	12:30	G	W																	
TDS (1)	8/30	12:30	G	W																	
DRO (2)	8/30	12:30	G	W																	
phosphorus (1)	8/30	12:30	G	W																	
			G	W																	

Preservation Codes:

A - HCL	M - Hexane
B - NaOH	N - None
C - Zn Acetate	O - AsNaO2
D - Nitric Acid	P - Na2O4S
E - NaHSO4	Q - Na2SO3
F - MeOH	R - Na2S2O3
G - Amchlor	S - H2SO4
H - Ascorbic Acid	T - TSP Dodecahydrate
I - Ice	U - Acetone
J - DI Water	V - MCAA
K - EDTA	W - pH 4-5
L - EDA	Z - other (specify)

Other:

Possible Hazard Identification
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return To Client ☐ Disposal By Lab ☐ Archive For ____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: Owen Mills Date: 8-8-18 Time 10:52 Method of Shipment: Hand delivered

Relinquished by	Date/Time	Company	Received by	Date/Time	Company
Jarrod Maly	8/30/18	DtB	Fed Ex		
				8-31-18 1000	NAS

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 5.4

Ver: 08/04/2016

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-158407-1
TestAmerica Sample Delivery Group: Alfalfa County Mississippi
Client Project/Site: OWRB Study Phase II
Revision: 1

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Dr. James Rosenblum

Jennifer Gambill

Authorized for release by:
9/20/2018 1:06:39 PM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

LINKS

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Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-158407-1	Alfalfa County Mississippi	Water	08/30/18 11:00	08/31/18 10:00

Job ID: 490-158407-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-158407-1

Revised Report
The following report has been revised to include the Gamma Spec NORM and Gross Alpha/Beta results.

Comments
No additional comments.

Receipt
The sample was received on 8/31/2018 10:00 AM; the sample arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 5.3º C.

GC/MS VOA
Method(s) 8260B: The following sample was collected in properly preserved vials for analysis of volatile organic compounds (VOCs): Alfalfa County Mississippi (490-158407-1). However, the pH was outside the required criteria when verified by the laboratory, and corrective action was not possible.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

HPLC/IC
Method(s) 300.0: The method blank for analytical batch 490-540172 contained Bromide above the method detection limit. This target analyte concentration was less than half the reporting limit (1/2RL); therefore, re-extraction and re-analysis of samples was not performed.

Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Alfalfa County Mississippi (490-158407-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: Due to the nature of the sample matrix, a matrix spike / matrix spike duplicate (MS/MSD) was not analyzed with 490-540172. However, the laboratory control sample / laboratory control sample duplicate (LCS/LCSD) recoveries were within the acceptance limits.

Method(s) 300.0: The continuing calibration verification (CCV) associated with batch 490-540173 recovered above the upper control limit for Nitrate as N and Nitrite as N. The following sample associated with this CCV was non-detect for the affected analytes; therefore, the data have been reported: (CCV 490-540173/14).

Method(s) 300.0: Due to the nature of the sample matrix, a matrix spike / matrix spike duplicate (MS/MSD) was not analyzed with 490-540173. However, the laboratory control sample / laboratory control sample duplicate (LCS/LCSD) recoveries were within the acceptance limits.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC VOA
Method(s) OK GRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate/sample duplicate (MS/MSD/DUP) associated with analytical batch 490-540861.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-540779 and analytical batch 490-540986.

Method(s) OK DRO: The following sample was diluted to bring the concentration of target analytes within the calibration range: Alfalfa County Mississippi (490-158407-1). Elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Job ID: 490-158407-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

General Chemistry
Method(s) 365.4: The matrix spike (MS) recovery for preparation batch 490-540980 and analytical batch 490-541324 was outside control limits. Non-homogeneity is suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD
Method(s) 901.1: Gamma Prep Batch 160-387783: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Alfalfa County Mississippi (490-158407-1), (LCS 160-387783/2-A), (MB 160-387783/1-A), (490-158404-O-1-A) and (490-158404-O-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-387783: The following sample exhibited a negative result greater in magnitude than the 3 sigma TPU: (490-158404-O-1-A). This occurrence was evaluated and determined to be random in nature. Sporadic occurrences such as this are statistically expected. No further action is required.

Method(s) 901.1: Gamma Prep Batch 160-384024: The relative percent difference (RPD) and replicate error ratio (RER) is outside of the acceptance limits of 40%/1 for the following samples: (490-158404-O-1-A) and (490-158404-O-1-B DU). Both the sample and duplicate activity are less than the minimum detectable concentration (MDC). The data have been reported with this narrative.

Method(s) 901.1: Gamma Prep Batch 160-387783: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative. Alfalfa County Mississippi (490-158407-1), (490-158404-O-1-A) and (490-158404-O-1-B DU).

Method(s) 9310: Gross Alpha/Beta Prep Batch 160-388469: The gross alpha and gross beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Alfalfa County Mississippi (490-158407-1), (160-30465-A-3-B) and (160-30465-A-3-C DU). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Definitions/Glossary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Qualifiers

HPLC/IC

Qualifier	Qualifier Description
B	Compound was found in the blank and sample.
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

Metals

Qualifier	Qualifier Description
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.

General Chemistry

Qualifier	Qualifier Description
F1	MS and/or MSD Recovery is outside acceptance limits.
F2	MS/MSD RPD exceeds control limits
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.
F	Duplicate RPD exceeds the control limit

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Client Sample ID: Alfalfa County Mississippi

Lab Sample ID: 490-158407-1

Date Collected: 08/30/18 11:00
Matrix: Water
Date Received: 08/31/18 10:00

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	**482**		10.0	2.00	ug/L			08/31/18 16:22	10
Ethylbenzene	**6.43**		1.00	0.190	ug/L			08/31/18 15:29	1
Toluene	**162**		1.00	0.170	ug/L			08/31/18 15:29	1
Xylenes, Total	**24.4**		3.00	0.580	ug/L			08/31/18 15:29	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*128*		*70 - 130*		*08/31/18 15:29*	*1*
1,2-Dichloroethane-d4 (Surr)	*116*		*70 - 130*		*08/31/18 16:22*	*10*
4-Bromofluorobenzene (Surr)	*109*		*70 - 130*		*08/31/18 15:29*	*1*
4-Bromofluorobenzene (Surr)	*116*		*70 - 130*		*08/31/18 16:22*	*10*
Dibromofluoromethane (Surr)	*100*		*70 - 130*		*08/31/18 15:29*	*1*
Dibromofluoromethane (Surr)	*99*		*70 - 130*		*08/31/18 16:22*	*10*
Toluene-d8 (Surr)	*95*		*70 - 130*		*08/31/18 15:29*	*1*
Toluene-d8 (Surr)	*93*		*70 - 130*		*08/31/18 16:22*	*10*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	**4520**		100	50.0	ug/L			09/06/18 11:05	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*81*		*70 - 130*		*09/06/18 11:05*	*5*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	**1440**		176	88.0	ug/L		09/05/18 15:04	09/06/18 18:18	2

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*86*		*50 - 150*	*09/05/18 15:04*	*09/06/18 18:18*	*2*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	**1580**	**B**	200	10.0	mg/L			08/31/18 20:32	200
Nitrate as N	ND		20.0	10.0	mg/L			08/31/18 20:32	200
Chloride	**210000**		10000	7000	mg/L			09/10/18 19:31	10000
Nitrite as N	ND		20.0	10.0	mg/L			08/31/18 20:32	200
Fluoride	ND		5.00	3.00	mg/L			08/31/18 20:18	50
Sulfate	**385**		50.0	30.0	mg/L			08/31/18 20:18	50

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	**0.224**		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 20:17	1
Antimony	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Arsenic	ND		0.100	0.0860	mg/L		09/01/18 09:59	09/08/18 20:28	10
Barium	**2.10**		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Beryllium	ND		0.00400	0.00200	mg/L		09/01/18 09:59	09/07/18 20:17	1
Cadmium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Calcium	**6920**		10.0	5.00	mg/L		09/01/18 09:59	09/08/18 20:28	10
Chromium	ND		0.0500	0.0300	mg/L		09/01/18 09:59	09/08/18 20:28	10
Cobalt	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Copper	**0.0202**		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 20:17	1
Iron	**27.7**		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 20:17	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Client Sample ID: Alfalfa County Mississippi

Lab Sample ID: 490-158407-1

Date Collected: 08/30/18 11:00
Matrix: Water
Date Received: 08/31/18 10:00

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Lead	**0.131**		0.0500	0.0200	mg/L		09/01/18 09:59	09/08/18 20:28	10
Magnesium	**1550**		10.0	2.50	mg/L		09/01/18 09:59	09/08/18 20:28	10
Manganese	**0.717**		0.150	0.0500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Nickel	**0.0320**	**J**	0.100	0.0300	mg/L		09/01/18 09:59	09/08/18 20:28	10
Potassium	**305**		10.0	5.00	mg/L		09/01/18 09:59	09/08/18 20:28	10
Selenium	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Silver	ND		0.0500	0.0300	mg/L		09/01/18 09:59	09/08/18 20:28	10
Sodium	**24800**		100	40.0	mg/L		09/01/18 09:59	09/10/18 19:31	100
Thallium	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/08/18 20:28	10
Vanadium	ND		0.0200	0.0100	mg/L		09/01/18 09:59	09/07/18 20:17	1
Zinc	ND		0.500	0.250	mg/L		09/01/18 09:59	09/08/18 20:28	10

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**23700**		10.0	5.00	mg/L			09/17/18 13:21	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/06/18 10:55	09/07/18 09:05	1
Bicarbonate Alkalinity as CaCO3	**50.7**		10.0	5.00	mg/L			09/06/18 14:04	1
Alkalinity	**50.7**		10.0	5.00	mg/L			09/06/18 14:04	1
Total Dissolved Solids	**186000**		1000	700	mg/L			09/05/18 20:48	1
pH	**6.3**	**HF**	0.1	0.1	SU			08/31/18 18:07	1
Total Organic Carbon	**54.7**		2.00	1.00	mg/L			09/04/18 06:07	2

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	32.4	U	89.7	89.8		180	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Actinium-228	14.0	U	33.3	33.3		78.7	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Bismuth-212	-14.4	U	168	168		272	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Bismuth-214	**452**		47.0	65.3		28.4	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Lead-210	-71.3	U	216	217		322	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Lead-212	0.599	U	33.7	33.7		56.9	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Lead-214	**479**		51.0	71.2		38.7	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Potassium-40	20.3	U	169	169		215	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Protactinium-231	0.000	U	166	166		1250	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Radium-226	**1320**	**G**	260	342	125	264	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Radium-228	14.0	U	33.3	33.3		78.7	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Thallium-208	3.59	U	10.5	10.5		13.1	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Thorium-232	14.0	U	33.3	33.3		78.7	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Thorium-234	-80.4	U	189	189		321	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Uranium-235	44.3	U	80.6	80.8		149	pCi/L	09/07/18 09:32	09/07/18 17:10	1
Uranium-238	-80.4	U	189	189		321	pCi/L	09/07/18 09:32	09/07/18 17:10	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/07/18 09:32*	*09/07/18 17:10*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Client Sample ID: Alfalfa County Mississippi

Lab Sample ID: 490-158407-1

Date Collected: 08/30/18 11:00
Matrix: Water
Date Received: 08/31/18 10:00

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	2210	U G	1740	1750	3.00	2550	pCi/L	09/11/18 10:38	09/12/18 10:52	1
Gross Beta	277	U G	1060	1060	4.00	1800	pCi/L	09/11/18 10:38	09/12/18 10:52	1

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-540000/6
Matrix: Water
Analysis Batch: 540000

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			08/31/18 12:38	1
Ethylbenzene	ND		1.00	0.190	ug/L			08/31/18 12:38	1
Toluene	ND		1.00	0.170	ug/L			08/31/18 12:38	1
Xylenes, Total	ND		3.00	0.580	ug/L			08/31/18 12:38	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*114*		*70 - 130*		*08/31/18 12:38*	*1*
4-Bromofluorobenzene (Surr)	*113*		*70 - 130*		*08/31/18 12:38*	*1*
Dibromofluoromethane (Surr)	*103*		*70 - 130*		*08/31/18 12:38*	*1*
Toluene-d8 (Surr)	*100*		*70 - 130*		*08/31/18 12:38*	*1*

Lab Sample ID: LCS 490-540000/3
Matrix: Water
Analysis Batch: 540000

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	22.56		ug/L		113	70 - 130
Ethylbenzene	20.0	23.68		ug/L		118	70 - 130
Toluene	20.0	20.43		ug/L		102	70 - 130
Xylenes, Total	40.0	47.67		ug/L		119	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*115*		*70 - 130*
4-Bromofluorobenzene (Surr)	*113*		*70 - 130*
Dibromofluoromethane (Surr)	*98*		*70 - 130*
Toluene-d8 (Surr)	*91*		*70 - 130*

Lab Sample ID: 490-158454-B-1 MS
Matrix: Water
Analysis Batch: 540000

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	22.06		ug/L		110	55 - 147
Ethylbenzene	ND		20.0	23.55		ug/L		118	65 - 139
Toluene	ND		20.0	21.73		ug/L		109	64 - 136
Xylenes, Total	ND		40.0	49.08		ug/L		123	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*115*		*70 - 130*
4-Bromofluorobenzene (Surr)	*116*		*70 - 130*
Dibromofluoromethane (Surr)	*98*		*70 - 130*
Toluene-d8 (Surr)	*101*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-158454-C-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540000

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	22.57		ug/L		113	55 - 147	2	22
Ethylbenzene	ND		20.0	24.77		ug/L		124	65 - 139	5	18
Toluene	ND		20.0	22.54		ug/L		113	64 - 136	4	18
Xylenes, Total	ND		40.0	50.31		ug/L		126	69 - 132	2	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*
4-Bromofluorobenzene (Surr)	*114*		*70 - 130*
Dibromofluoromethane (Surr)	*99*		*70 - 130*
Toluene-d8 (Surr)	*100*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-540861/5 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540861

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			09/06/18 08:41	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*102*		*70 - 130*		*09/06/18 08:41*	*1*

Lab Sample ID: LCS 490-540861/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540861

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
C6-C10 OK			200	200.7		ug/L		100	80 - 120		

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*102*		*70 - 130*

Lab Sample ID: LCSD 490-540861/36 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540861

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK			200	219.0		ug/L		110	80 - 120	9	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*104*		*70 - 130*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-540779/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540986 — **Prep Batch: 540779**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		09/05/18 15:03	09/06/18 13:33	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*85*		*50 - 150*	*09/05/18 15:03*	*09/06/18 13:33*	*1*

Lab Sample ID: LCS 490-540779/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540986 — **Prep Batch: 540779**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	443.6		ug/L		89	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*92*		*50 - 150*

Lab Sample ID: LCSD 490-540779/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540986 — **Prep Batch: 540779**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	470.1		ug/L		94	80 - 120	6	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*95*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-540172/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540172

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	0.3487	J	1.00	0.0500	mg/L			08/31/18 18:05	1
Chloride	ND		1.00	0.700	mg/L			08/31/18 18:05	1
Fluoride	ND		0.100	0.0600	mg/L			08/31/18 18:05	1
Sulfate	ND		1.00	0.600	mg/L			08/31/18 18:05	1

Lab Sample ID: LCS 490-540172/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540172

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.794		mg/L		98	90 - 110
Chloride	10.0	9.411		mg/L		94	90 - 110
Fluoride	1.00	1.036		mg/L		103	90 - 110
Sulfate	10.0	10.74		mg/L		107	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-540172/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540172

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.839		mg/L		98	90 - 110	0	20
Chloride	10.0	9.478		mg/L		95	90 - 110	1	20
Fluoride	1.00	1.048		mg/L		105	90 - 110	1	20
Sulfate	10.0	10.79		mg/L		108	90 - 110	0	20

Lab Sample ID: MB 490-540173/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540173

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			08/31/18 18:05	1
Nitrite as N	ND		0.100	0.0500	mg/L			08/31/18 18:05	1

Lab Sample ID: LCS 490-540173/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540173

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	0.9717		mg/L		97	90 - 110
Nitrite as N	1.00	1.059		mg/L		106	90 - 110

Lab Sample ID: LCSD 490-540173/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540173

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	0.9838		mg/L		98	90 - 110	1	20
Nitrite as N	1.00	1.055		mg/L		105	90 - 110	0	20

Lab Sample ID: MB 490-541752/29 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			09/10/18 18:33	1
Chloride	ND		1.00	0.700	mg/L			09/10/18 18:33	1
Fluoride	ND		0.100	0.0600	mg/L			09/10/18 18:33	1
Sulfate	ND		1.00	0.600	mg/L			09/10/18 18:33	1

Lab Sample ID: MB 490-541752/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			09/10/18 13:27	1
Chloride	ND		1.00	0.700	mg/L			09/10/18 13:27	1
Fluoride	ND		0.100	0.0600	mg/L			09/10/18 13:27	1
Sulfate	ND		1.00	0.600	mg/L			09/10/18 13:27	1

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCS 490-541752/30 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.564		mg/L		95	90 - 110
Chloride	10.0	10.00		mg/L		100	90 - 110
Fluoride	1.00	0.9974		mg/L		100	90 - 110
Sulfate	10.0	9.754		mg/L		97	90 - 110

Lab Sample ID: LCS 490-541752/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.539		mg/L		95	90 - 110
Chloride	10.0	9.959		mg/L		99	90 - 110
Fluoride	1.00	0.9868		mg/L		99	90 - 110
Sulfate	10.0	9.879		mg/L		99	90 - 110

Lab Sample ID: LCSD 490-541752/31 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.574		mg/L		96	90 - 110	0	20
Chloride	10.0	10.01		mg/L		100	90 - 110	0	20
Fluoride	1.00	1.011		mg/L		101	90 - 110	1	20
Sulfate	10.0	9.913		mg/L		99	90 - 110	2	20

Lab Sample ID: LCSD 490-541752/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.524		mg/L		95	90 - 110	0	20
Chloride	10.0	9.928		mg/L		99	90 - 110	0	20
Fluoride	1.00	0.9806		mg/L		98	90 - 110	1	20
Sulfate	10.0	9.863		mg/L		98	90 - 110	0	20

Lab Sample ID: 490-158493-K-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541752

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	0.445	J	10.0	10.16		mg/L		97	80 - 120
Chloride	8.79		10.0	19.42		mg/L		106	80 - 120
Fluoride	0.101		1.00	1.078		mg/L		98	80 - 120
Sulfate	21.4		10.0	31.35		mg/L		99	80 - 120

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-540220/1-A
Matrix: Water
Analysis Batch: 541430

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 540220

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Antimony	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Arsenic	ND		0.0100	0.00860	mg/L		09/01/18 09:59	09/07/18 18:05	1
Barium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Beryllium	ND		0.00400	0.00200	mg/L		09/01/18 09:59	09/07/18 18:05	1
Cadmium	ND		0.00100	0.000500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Calcium	ND		1.00	0.500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Chromium	ND		0.00500	0.00300	mg/L		09/01/18 09:59	09/07/18 18:05	1
Cobalt	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Copper	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Iron	ND		0.100	0.0500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Lead	ND		0.00500	0.00200	mg/L		09/01/18 09:59	09/07/18 18:05	1
Magnesium	ND		1.00	0.250	mg/L		09/01/18 09:59	09/07/18 18:05	1
Manganese	ND		0.0150	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Nickel	ND		0.0100	0.00300	mg/L		09/01/18 09:59	09/07/18 18:05	1
Potassium	ND		1.00	0.500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Selenium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Silver	ND		0.00500	0.00300	mg/L		09/01/18 09:59	09/07/18 18:05	1
Sodium	ND		1.00	0.400	mg/L		09/01/18 09:59	09/07/18 18:05	1
Thallium	ND		0.0100	0.00500	mg/L		09/01/18 09:59	09/07/18 18:05	1
Vanadium	ND		0.0200	0.0100	mg/L		09/01/18 09:59	09/07/18 18:05	1
Zinc	ND		0.0500	0.0250	mg/L		09/01/18 09:59	09/07/18 18:05	1

Lab Sample ID: LCS 490-540220/24-A
Matrix: Water
Analysis Batch: 541430

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 540220

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Silver	0.0500	0.04710		mg/L		94	85 - 115

Lab Sample ID: LCS 490-540220/2-A
Matrix: Water
Analysis Batch: 541430

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 540220

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	0.9840		mg/L		98	85 - 115
Antimony	0.100	0.09880		mg/L		99	85 - 115
Arsenic	0.100	0.1000		mg/L		100	85 - 115
Barium	0.100	0.1027		mg/L		103	85 - 115
Beryllium	0.100	0.1001		mg/L		100	85 - 115
Cadmium	0.100	0.1012		mg/L		101	85 - 115
Calcium	10.0	9.829		mg/L		98	85 - 115
Chromium	0.100	0.1029		mg/L		103	85 - 115
Cobalt	0.100	0.1048		mg/L		105	85 - 115
Copper	0.100	0.1081		mg/L		108	85 - 115
Iron	1.00	1.003		mg/L		100	85 - 115
Lead	0.100	0.1041		mg/L		104	85 - 115
Magnesium	10.0	10.39		mg/L		104	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-540220/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Manganese	0.100	0.09720		mg/L		97	85 - 115
Nickel	0.100	0.1050		mg/L		105	85 - 115
Potassium	10.0	10.14		mg/L		101	85 - 115
Selenium	0.100	0.1075		mg/L		108	85 - 115
Sodium	10.0	10.07		mg/L		101	85 - 115
Thallium	0.100	0.1007		mg/L		101	85 - 115
Vanadium	0.100	0.1042		mg/L		104	85 - 115
Zinc	0.100	0.1056		mg/L		106	85 - 115

Lab Sample ID: LCSD 490-540220/25-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Silver	0.0500	0.04890		mg/L		98	85 - 115	4	20

Lab Sample ID: LCSD 490-540220/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	1.00	0.9816		mg/L		98	85 - 115	0	20
Antimony	0.100	0.09870		mg/L		99	85 - 115	0	20
Arsenic	0.100	0.09990		mg/L		100	85 - 115	0	20
Barium	0.100	0.1022		mg/L		102	85 - 115	0	20
Beryllium	0.100	0.09990		mg/L		100	85 - 115	0	20
Cadmium	0.100	0.1009		mg/L		101	85 - 115	0	20
Calcium	10.0	9.790		mg/L		98	85 - 115	0	20
Chromium	0.100	0.1026		mg/L		103	85 - 115	0	20
Cobalt	0.100	0.1041		mg/L		104	85 - 115	1	20
Copper	0.100	0.1091		mg/L		109	85 - 115	1	20
Iron	1.00	1.002		mg/L		100	85 - 115	0	20
Lead	0.100	0.1039		mg/L		104	85 - 115	0	20
Magnesium	10.0	10.33		mg/L		103	85 - 115	1	20
Manganese	0.100	0.09690		mg/L		97	85 - 115	0	20
Nickel	0.100	0.1052		mg/L		105	85 - 115	0	20
Potassium	10.0	10.13		mg/L		101	85 - 115	0	20
Selenium	0.100	0.1113		mg/L		111	85 - 115	3	20
Sodium	10.0	10.01		mg/L		100	85 - 115	1	20
Thallium	0.100	0.1008		mg/L		101	85 - 115	0	20
Vanadium	0.100	0.1045		mg/L		105	85 - 115	0	20
Zinc	0.100	0.1060		mg/L		106	85 - 115	0	20

Lab Sample ID: 490-158268-A-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541430 — **Prep Batch: 540220**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	0.120		1.00	1.077		mg/L		96	70 - 130

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: 490-158268-A-1-B MS
Matrix: Water
Analysis Batch: 541430

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 540220

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Antimony	ND		0.100	0.1007		mg/L		101	70 - 130
Arsenic	ND		0.100	0.1014		mg/L		101	70 - 130
Barium	0.00510	J	0.100	0.1081		mg/L		103	70 - 130
Beryllium	ND		0.100	0.1001		mg/L		100	70 - 130
Cadmium	ND		0.100	0.1005		mg/L		101	70 - 130
Chromium	ND		0.100	0.1029		mg/L		103	70 - 130
Cobalt	ND		0.100	0.1044		mg/L		104	70 - 130
Copper	0.0199		0.100	0.1210		mg/L		101	70 - 130
Iron	0.141		1.00	1.143		mg/L		100	70 - 130
Lead	0.00210	J	0.100	0.1042		mg/L		102	70 - 130
Magnesium	0.898	J	10.0	11.20		mg/L		103	70 - 130
Manganese	0.00920	J	0.100	0.1049		mg/L		96	70 - 130
Nickel	ND		0.100	0.1055		mg/L		106	70 - 130
Selenium	ND		0.100	0.1087		mg/L		109	70 - 130
Thallium	ND		0.100	0.09950		mg/L		100	70 - 130
Vanadium	ND		0.100	0.1030		mg/L		103	70 - 130
Zinc	0.0254	J	0.100	0.1311		mg/L		106	70 - 130

Lab Sample ID: 490-158268-A-1-C MSD
Matrix: Water
Analysis Batch: 541430

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA
Prep Batch: 540220

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	0.120		1.00	0.9423		mg/L		82	70 - 130	13	20
Antimony	ND		0.100	0.08930		mg/L		89	70 - 130	12	20
Arsenic	ND		0.100	0.09070		mg/L		91	70 - 130	11	20
Barium	0.00510	J	0.100	0.09560		mg/L		91	70 - 130	12	20
Beryllium	ND		0.100	0.08800		mg/L		88	70 - 130	13	20
Cadmium	ND		0.100	0.08950		mg/L		90	70 - 130	12	20
Chromium	ND		0.100	0.09050		mg/L		91	70 - 130	13	20
Cobalt	ND		0.100	0.09190		mg/L		92	70 - 130	13	20
Copper	0.0199		0.100	0.1080		mg/L		88	70 - 130	11	20
Iron	0.141		1.00	1.005		mg/L		86	70 - 130	13	20
Lead	0.00210	J	0.100	0.09230		mg/L		90	70 - 130	12	20
Magnesium	0.898	J	10.0	9.883		mg/L		90	70 - 130	12	20
Manganese	0.00920	J	0.100	0.09500		mg/L		86	70 - 130	10	20
Nickel	ND		0.100	0.09270		mg/L		93	70 - 130	13	20
Selenium	ND		0.100	0.09410		mg/L		94	70 - 130	14	20
Thallium	ND		0.100	0.09110		mg/L		91	70 - 130	9	20
Vanadium	ND		0.100	0.09500		mg/L		95	70 - 130	8	20
Zinc	0.0254	J	0.100	0.1159		mg/L		91	70 - 130	12	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-540980/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/06/18 10:55	09/07/18 05:52	1

Lab Sample ID: LCS 490-540980/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	2.130		mg/L		107	90 - 110

Lab Sample ID: LCSD 490-540980/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.00	1.940		mg/L		97	90 - 110	9	20

Lab Sample ID: 490-158502-F-1-E MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541324 — **Prep Batch: 540980**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	ND	F1	2.00	1.400	F1	mg/L		70	73 - 119

Lab Sample ID: 490-158502-F-1-F MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542066 — **Prep Batch: 540980**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	ND	F1	2.00	1.750		mg/L		88	73 - 119	22	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-541058/29 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			09/06/18 12:41	1
Alkalinity	ND		10.0	5.00	mg/L			09/06/18 12:41	1

Lab Sample ID: LCS 490-541058/30 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	94.76		mg/L		95	90 - 110

Method: SM 2320B - Alkalinity (Continued)

Lab Sample ID: LCSD 490-541058/46 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity			100	99.00		mg/L		99	90 - 110	4	20

Lab Sample ID: 490-158407-1 DU — **Client Sample ID: Alfalfa County Mississippi**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 541058

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	50.7			50.52		mg/L				0.3	20
Alkalinity	50.7			50.52		mg/L				0.3	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-533218/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533218

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			09/05/18 20:48	1

Lab Sample ID: LCS 490-533218/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533218

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Dissolved Solids			100	94.00		mg/L		94	90 - 110		

Lab Sample ID: 490-158309-N-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 533218

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	240			263.0		mg/L				9	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-158397-H-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540195

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	7.6			7.6		SU				0	20

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: MB 490-540610/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			09/04/18 06:07	1

Lab Sample ID: LCS 490-540610/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	10.0	9.459		mg/L		95	90 - 110

Lab Sample ID: LCSD 490-540610/7 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	10.0	9.664		mg/L		97	90 - 110	2	20

Lab Sample ID: 490-158404-G-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	34.4	F1 F2	20.0	40.30	F1	mg/L		30	74 - 134

Lab Sample ID: 490-158404-G-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 540610

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	34.4	F1 F2	20.0	50.08	F2	mg/L		79	74 - 134	22	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-387783/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 387764 — **Prep Batch: 387783**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	38.69	U	110	110		107	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Actinium-228	2.277	U	36.4	36.4		45.9	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Bismuth-212	38.64	U	113	113		197	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Bismuth-214	-8.544	U	20.1	20.1		36.7	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Lead-210	143.5	U	154	157		205	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Lead-212	-3.859	U	18.0	18.0		31.3	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Lead-214	5.800	U	3.34	3.39		31.6	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Potassium-40	-29.40	U	125	125		184	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Protactinium-231	-0.00002294	U	342	342		590	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Radium-226	66.28	U G	158	158	125	268	pCi/L	09/07/18 09:32	09/07/18 14:30	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: MB 160-387783/1-A
Matrix: Water
Analysis Batch: 387764

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 387783

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Radium-228	2.277	U	36.4	36.4		45.9	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Thallium-208	-8.234	U	11.1	11.1		16.0	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Thorium-232	2.277	U	36.4	36.4		45.9	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Thorium-234	-102.2	U	121	122		212	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Uranium-235	24.58	U	50.0	50.0		81.0	pCi/L	09/07/18 09:32	09/07/18 14:30	1
Uranium-238	-102.2	U	121	122		212	pCi/L	09/07/18 09:32	09/07/18 14:30	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/07/18 09:32*	*09/07/18 14:30*	*1*

Lab Sample ID: LCS 160-387783/2-A
Matrix: Water
Analysis Batch: 387765

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 387783

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Americium-241			136000	132600		15300		534	pCi/L	97	90 - 111		
Cesium-137			45400	43750		4390		160	pCi/L	96	90 - 111		
Cobalt-60			32400	31160		3090		93.7	pCi/L	96	89 - 110		

Lab Sample ID: 490-158404-O-1-B DU
Matrix: Water
Analysis Batch: 387764

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 387783

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Actinium-227	-16.2	U		64.74	U	127		120	pCi/L			0.44	1
Actinium-228	61.3			53.88		37.3		38.6	pCi/L			0.1	1
Bismuth-212	-15.6	U		-38.55	U	141		242	pCi/L			0.07	1
Bismuth-214	49.9			45.18		17.6		19.9	pCi/L			0.11	1
Lead-210	65.2	U		21.11	U	115		188	pCi/L			0.16	1
Lead-212	-8.25	U		-2.155	U	21.6		37.0	pCi/L			0.14	1
Lead-214	69.2			71.65		20.5		25.1	pCi/L			0.05	1
Potassium-40	196	U		370.9		145		145	pCi/L			0.52	1
Protactinium-231	104	U		0.0000	U	47.1		663	pCi/L			0.25	1
Radium-226	0.000	U G		-9.044	U G	172	125	299	pCi/L			0.02	1
Radium-228	61.3			53.88		37.3		38.6	pCi/L			0.1	1
Thallium-208	8.34	U		3.953	U	7.34		15.1	pCi/L			0.20	1
Thorium-232	61.3			53.88		37.3		38.6	pCi/L			0.1	1
Thorium-234	-241	U		86.65	U F	89.6		145	pCi/L			1.42	1
Uranium-235	29.8	U		-27.48	U	59.9		120	pCi/L			0.47	1
Uranium-238	-241	U		86.65	U F	89.6		145	pCi/L			1.42	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: 490-158404-O-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 387764 — **Prep Batch: 387783**

Other Detected Radionuclides	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Other Detected Radionuclide	None			None					pCi/L				

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-388469/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.6611	U	0.553	0.558	3.00	0.831	pCi/L	09/11/18 10:38	09/12/18 10:51	1
Gross Beta	0.2506	U	0.533	0.533	4.00	0.895	pCi/L	09/11/18 10:38	09/12/18 10:51	1

Lab Sample ID: LCS 160-388469/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha			51.0	43.51		6.42	3.00	1.38	pCi/L	85	73 - 133		

Lab Sample ID: LCSB 160-388469/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte			Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta			87.8	89.78		9.52	4.00	1.19	pCi/L	102	75 - 125		

Lab Sample ID: 160-30465-A-3-D MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha	3.72	U G	291	255.0		39.6	3.00	11.5	pCi/L	86	60 - 140		

Lab Sample ID: 160-30465-A-3-E MSBT — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 388633 — **Prep Batch: 388469**

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta	21.2	G	502	511.8	G	54.3	4.00	5.32	pCi/L	98	60 - 140		

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Method: 9310 - Gross Alpha / Beta (GFPC) (Continued)

Lab Sample ID: 160-30465-A-3-C DU
Matrix: Water
Analysis Batch: 388633

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 388469

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Gross Alpha	3.72	U G		-2.272	U G	5.97	3.00	12.5	pCi/L			0.49	1
Gross Beta	21.2	G		26.03	G	5.72	4.00	5.70	pCi/L			0.44	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

GC/MS VOA

Analysis Batch: 540000

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	8260B	
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	8260B	
MB 490-540000/6	Method Blank	Total/NA	Water	8260B	
LCS 490-540000/3	Lab Control Sample	Total/NA	Water	8260B	
490-158454-B-1 MS	Matrix Spike	Total/NA	Water	8260B	
490-158454-C-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 540861

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	OK GRO	
MB 490-540861/5	Method Blank	Total/NA	Water	OK GRO	
LCS 490-540861/4	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-540861/36	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 540779

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	3510C	
MB 490-540779/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-540779/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-540779/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 540986

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	OK DRO	540779
MB 490-540779/1-A	Method Blank	Total/NA	Water	OK DRO	540779
LCS 490-540779/2-A	Lab Control Sample	Total/NA	Water	OK DRO	540779
LCSD 490-540779/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	540779

HPLC/IC

Analysis Batch: 540172

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	300.0	
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	300.0	
MB 490-540172/3	Method Blank	Total/NA	Water	300.0	
LCS 490-540172/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-540172/5	Lab Control Sample Dup	Total/NA	Water	300.0	

Analysis Batch: 540173

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	300.0	
MB 490-540173/3	Method Blank	Total/NA	Water	300.0	
LCS 490-540173/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-540173/5	Lab Control Sample Dup	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 541752

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	300.0	
MB 490-541752/29	Method Blank	Total/NA	Water	300.0	
MB 490-541752/3	Method Blank	Total/NA	Water	300.0	
LCS 490-541752/30	Lab Control Sample	Total/NA	Water	300.0	
LCS 490-541752/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-541752/31	Lab Control Sample Dup	Total/NA	Water	300.0	
LCSD 490-541752/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-158493-K-1 MS	Matrix Spike	Total/NA	Water	300.0	

Metals

Prep Batch: 540220

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	200.7	
MB 490-540220/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-540220/24-A	Lab Control Sample	Total/NA	Water	200.7	
LCS 490-540220/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-540220/25-A	Lab Control Sample Dup	Total/NA	Water	200.7	
LCSD 490-540220/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	
490-158268-A-1-B MS	Matrix Spike	Total/NA	Water	200.7	
490-158268-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7	

Analysis Batch: 541430

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	200.7 Rev 4.4	540220
MB 490-540220/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	540220
LCS 490-540220/24-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	540220
LCS 490-540220/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	540220
LCSD 490-540220/25-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	540220
LCSD 490-540220/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	540220
490-158268-A-1-B MS	Matrix Spike	Total/NA	Water	200.7 Rev 4.4	540220
490-158268-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	200.7 Rev 4.4	540220

Analysis Batch: 541550

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	200.7 Rev 4.4	540220

Analysis Batch: 541805

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	200.7 Rev 4.4	540220

Analysis Batch: 543312

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	SM 2340B	

General Chemistry

Analysis Batch: 533218

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	SM 2540C	

General Chemistry (Continued)

Analysis Batch: 533218 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-533218/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-533218/2	Lab Control Sample	Total/NA	Water	SM 2540C	
490-158309-N-1 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 540195

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	SM 4500 H+ B	
LCS 490-540195/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-158397-H-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Analysis Batch: 540610

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	SM 5310B	
MB 490-540610/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-540610/6	Lab Control Sample	Total/NA	Water	SM 5310B	
LCSD 490-540610/7	Lab Control Sample Dup	Total/NA	Water	SM 5310B	
490-158404-G-1 MS	Matrix Spike	Total/NA	Water	SM 5310B	
490-158404-G-1 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

Prep Batch: 540980

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	365.2/365.3/365	
MB 490-540980/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-540980/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-540980/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-158502-F-1-E MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-158502-F-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 541058

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	SM 2320B	
MB 490-541058/29	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-541058/30	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-541058/46	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-158407-1 DU	Alfalfa County Mississippi	Total/NA	Water	SM 2320B	

Analysis Batch: 541324

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	365.4	540980
MB 490-540980/1-A	Method Blank	Total/NA	Water	365.4	540980
LCS 490-540980/2-A	Lab Control Sample	Total/NA	Water	365.4	540980
LCSD 490-540980/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	540980
490-158502-F-1-E MS	Matrix Spike	Total/NA	Water	365.4	540980

Analysis Batch: 542066

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158502-F-1-F MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	540980

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Rad

Prep Batch: 387783

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	Fill_Geo-0	
MB 160-387783/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-387783/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
490-158404-O-1-B DU	Duplicate	Total/NA	Water	Fill_Geo-0	

Prep Batch: 388469

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-158407-1	Alfalfa County Mississippi	Total/NA	Water	Evaporation	
MB 160-388469/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-388469/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-388469/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
160-30465-A-3-D MS	Matrix Spike	Total/NA	Water	Evaporation	
160-30465-A-3-E MSBT	Matrix Spike	Total/NA	Water	Evaporation	
160-30465-A-3-C DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Client Sample ID: Alfalfa County Mississippi

Lab Sample ID: 490-158407-1

Date Collected: 08/30/18 11:00

Matrix: Water

Date Received: 08/31/18 10:00

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	5 mL	5 mL	540000	08/31/18 15:29	P1B	TAL NSH
Total/NA	Analysis	8260B		10	5 mL	5 mL	540000	08/31/18 16:22	P1B	TAL NSH
Total/NA	Analysis	OK GRO		5	5 mL	5 mL	540861	09/06/18 11:05	S1S	TAL NSH
Total/NA	Prep	3510C			1135.8 mL	1 mL	540779	09/05/18 15:04	KWS	TAL NSH
Total/NA	Analysis	OK DRO		2			540986	09/06/18 18:18	GMH	TAL NSH
Total/NA	Analysis	300.0		50			540172	08/31/18 20:18	SW1	TAL NSH
Total/NA	Analysis	300.0		200			540172	08/31/18 20:32	SW1	TAL NSH
Total/NA	Analysis	300.0		200			540173	08/31/18 20:32	SW1	TAL NSH
Total/NA	Analysis	300.0		10000			541752	09/10/18 19:31	JHS	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			541430	09/07/18 20:17	LDC	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		10			541550	09/08/18 20:28	LDC	TAL NSH
Total/NA	Prep	200.7			50.0 mL	50.0 mL	540220	09/01/18 09:59	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		100			541805	09/10/18 19:31	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			543312	09/17/18 13:21	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	540980	09/06/18 10:55	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	541324	09/07/18 09:05	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	541058	09/06/18 14:04	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	533218	09/05/18 20:48	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			540195	08/31/18 18:07	JDG	TAL NSH
Total/NA	Analysis	SM 5310B		2	50 mL	50 mL	540610	09/04/18 06:07	CLJ	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	387783	09/07/18 09:32	PK	TAL SL
Total/NA	Analysis	901.1		1			387764	09/07/18 17:10	KLS	TAL SL
Total/NA	Prep	Evaporation			0.1 mL	1.0 g	388469	09/11/18 10:38	SCB	TAL SL
Total/NA	Analysis	9310		1			388633	09/12/18 10:52	CDR	TAL SL

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-158407-1
SDG: Alfalfa County Mississippi

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-19
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-19
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-19
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-19
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-19
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-19
Nevada	State Program	9	MO000542018-1	07-31-19
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-19
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-19
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-18 *
West Virginia DEP	State Program	3	381	10-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-158407 Chain of Custody

Cooler Received/Opened On 8/31/2018 @ 1000

Time Samples Removed From Cooler_____ Time Samples Placed In Storage_____ (2 Hour Window)

1. Tracking # 8151 (last 4 digits, FedEx) Courier: FedEx

   IR Gun ID 31470366 pH Strip Lot_____ Chlorine Strip Lot_____

2. Temperature of rep. sample or temp blank when opened: 5.3 Degrees Celsius

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 front 1 back

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) _____

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence # NA

I certify that I unloaded the cooler and answered questions 7-14 (intial) EG

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) EG

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) EG

I certify that I attached a label with the unique LIMS number to each container (intial) EG

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment
Cooler Receipt Form.doc

LF-1
End of Form

Revised 8/23/17

9/20/2018 (Rev. 1)

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information

Client Contact: Dr. James Rosenblum
Company: CH2M Hill, Inc.
Address: 12377 Merit Drive Suite 1000
City: Dallas
State, Zip: TX, 75251
Phone: 248-939-3216(Tel)
Email: james.rosenblum@ch2m.com
Project Name: OWRB Study Phase II
Site:

Sampler: Jarrod Mays
Phone: 580 541 0319
Due Date Requested:
TAT Requested (days):
PO #:
WO #
Project #: 49013620
SSOW#:

Lab PM: Gambill, Jennifer
E-Mail: jennifer.gambill@testamericainc.com
Carrier Tracking No(s).
COC No:
Page: Page of
Job #:

Loc: 490
158407

Preservation Codes:

A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA, M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)

Other:

Alfalfa County Mississippi

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	8/30	11:00	G	W																	
Gross Alpha/Beta (1)	8/30	11:00	G	W																	
Alk/IC/pH (3)	8/30	11:00	G	W																	
Metals/Hardness (1)	8/30	11:00	G	W																	
TOC (1)	8/30	11:00	G	W																	
BTEX/GRO (6)	8/30	11:00	G	W																	
TDS (1)	8/30	11:00	G	W																	
DRO (2)	8/30	11:00	G	W																	
Phosphorus (1)	8/30	11:00	G	W																	
			G	W																	

Possible Hazard Identification
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return To Client ☐ Disposal By Lab ☐ Archive For _____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: Owen Mills Date: 8-8-18 Time: 10:52 Method of Shipment: Hand delivered

Relinquished by	Date/Time	Company	Received by	Date/Time	Company
Jarrod Mays	8/30/18	D&B	Fed Ex		
				8-31-18 1000	TA-NAS

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 5.3

Ver: 08/04/2016

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-159189-1
TestAmerica Sample Delivery Group: Rich SWD
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Mr. Michael Dunkel

Jennifer Gambill

Authorized for release by:
9/28/2018 6:52:47 PM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

The test results in this report meet all 2003 NELAC and 2009 TNI requirements for accredited parameters, exceptions are noted in this report. This report may not be reproduced except in full, and with written approval from the laboratory. For questions please contact the Project Manager at the e-mail address or telephone number listed on this page.

This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-159189-1	Rich SWD	Water	09/13/18 09:30	09/14/18 10:20
490-159189-2	Trip Blank	Water	09/13/18 00:01	09/14/18 10:20

Job ID: 490-159189-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-159189-1

Comments
No additional comments.

Receipt
The samples were received on 9/14/2018 10:20 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 4.1º C.

GC/MS VOA
Method(s) 8260B: Surrogate recovery for the following sample was outside control limits: Rich SWD (490-159189-1). Evidence of matrix interference is present; therefore, re-extraction and/or re-analysis was not performed.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

HPLC/IC
Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Rich SWD (490-159189-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: The matrix spike / matrix spike duplicate (MS/MSD) results for 490-542925 exceeded the calibration curve limit for chloride. (490-159206-E-6 MS) and (490-159206-E-6 MSD)

Method(s) 300.0: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-544169 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Method(s) 300.0: The method blank for analytical batch 490-544169 contained Bromide above the method detection limit. This target analyte concentration was less than half the reporting limit (1/2RL); therefore, re-extraction and re-analysis of samples was not performed.

Method(s) 300.0: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-544170 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Method(s) 300.0: Reanalysis of the following sample was performed outside of the analytical holding time due to samples matrix as well as failing QC: Rich SWD (490-159189-1).

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-544103 and analytical batch 490-544357.

Method(s) OK DRO: The following sample was diluted due to the abundance of target analytes: Rich SWD (490-159189-1). As such, surrogate recoveries are below the calibration range or are not reported, and elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Metals
Method(s) 200.7 Rev 4.4: The RPD of the laboratory control sample (LCS) and laboratory control sample duplicate (LCSD) for batch preparation batch 490-542965 and analytical batch 490-544281 recovered outside control limits for the following analytes: Aluminum, Arsenic, Barium, Chromium, Lead, Selenium, Beryllium, Cadmium, Calcium, Cobalt, Copper, Iron, Potassium, Magnesium, Manganese, Sodium, Nickel, Thallium, Vanadium and Zinc

Method(s) 200.7 Rev 4.4: The laboratory control sample duplicate (LCSD) for preparation batch 490-542965 and analytical batch

Job ID: 490-159189-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

490-544281 recovered outside control limits for the following analyte: Zinc. This analyte was biased high in the LCSD and was not detected in the associated samples; therefore, the data have been reported.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD

Method(s) 901.1: Gamma Prep Batch: 160-389656: The following samples, analyzed by gamma spectroscopy, did not meet the Ra-226 detection goal due to high concentrations of the analyte: (LCS 160-389656/2-A), (MB 160-389656/1-A), (160-30723-F-1-A) and (160-30723-F-1-B DU). The data have been reported.

Method(s) 901.1: Gamma Prep Batch 160-389656: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Rich SWD (490-159189-1), (LCS 160-389656/2-A), (MB 160-389656/1-A), (160-30723-F-1-A) and (160-30723-F-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-389656: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte. Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries: Rich SWD (490-159189-1), (LCS 160-389656/2-A), (MB 160-389656/1-A), (160-30723-F-1-A) and (160-30723-F-1-B DU). The results are estimated. The data have been reported with this narrative.

Method(s) 9310: Gamma Prep Batch 160-389969: The gross alpha detection goal was not met for the following samples due to a reduction of the sample size attributed to high residual mass: (160-30328-A-15-B) and (160-30328-A-15-E DU). Analytical results are reported with the detection limit achieved.

Method(s) 9310: Gamma Prep Batch 160-389969: The gross alpha and gross beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Rich SWD (490-159189-1). Analytical results are reported with the detection limit achieved.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Qualifiers

GC/MS VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

GC Semi VOA

Qualifier	Qualifier Description
X	Surrogate is outside control limits

HPLC/IC

Qualifier	Qualifier Description
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.
E	Result exceeded calibration range.
F1	MS and/or MSD Recovery is outside acceptance limits.
H	Sample was prepped or analyzed beyond the specified holding time

Metals

Qualifier	Qualifier Description
*	RPD of the LCS and LCSD exceeds the control limits
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.
*	LCS or LCSD is outside acceptance limits.

General Chemistry

Qualifier	Qualifier Description
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.
F	Duplicate RPD exceeds the control limit

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)

Glossary (Continued)

Abbreviation	These commonly used abbreviations may or may not be present in this report.
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Client Sample ID: Rich SWD

Date Collected: 09/13/18 09:30
Date Received: 09/14/18 10:20

Lab Sample ID: 490-159189-1

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	2290		25.0	5.00	ug/L			09/27/18 22:43	25
Ethylbenzene	351		10.0	1.90	ug/L			09/15/18 09:22	10
Toluene	1840		25.0	4.25	ug/L			09/27/18 22:43	25
Xylenes, Total	2440		30.0	5.80	ug/L			09/15/18 09:22	10

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*141*	*X*	*70 - 130*		*09/15/18 09:22*	*10*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*		*09/27/18 22:43*	*25*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*		*09/15/18 09:22*	*10*
4-Bromofluorobenzene (Surr)	*100*		*70 - 130*		*09/27/18 22:43*	*25*
Dibromofluoromethane (Surr)	*115*		*70 - 130*		*09/15/18 09:22*	*10*
Dibromofluoromethane (Surr)	*101*		*70 - 130*		*09/27/18 22:43*	*25*
Toluene-d8 (Surr)	*100*		*70 - 130*		*09/15/18 09:22*	*10*
Toluene-d8 (Surr)	*98*		*70 - 130*		*09/27/18 22:43*	*25*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	8110		200	100	ug/L			09/18/18 14:45	10

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*81*		*70 - 130*		*09/18/18 14:45*	*10*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	16600		1760	878	ug/L		09/20/18 08:30	09/21/18 15:21	20

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*0*	*X*	*50 - 150*	*09/20/18 08:30*	*09/21/18 15:21*	*20*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	711		200	10.0	mg/L			09/20/18 11:56	200
Nitrate as N	ND	H	20.0	10.0	mg/L			09/20/18 11:56	200
Chloride	89800		5000	3500	mg/L			09/20/18 12:08	5000
Nitrite as N	ND	H	20.0	10.0	mg/L			09/20/18 11:56	200
Fluoride	5.49		2.00	1.20	mg/L			09/15/18 00:34	20
Sulfate	553		20.0	12.0	mg/L			09/15/18 00:34	20

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND	*	0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Antimony	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Arsenic	ND	*	0.0100	0.00860	mg/L		09/15/18 09:53	09/20/18 14:01	1
Barium	0.0123	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Beryllium	ND	*	0.00400	0.00200	mg/L		09/15/18 09:53	09/20/18 14:01	1
Cadmium	ND	*	0.00100	0.000500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Calcium	13.0	*	1.00	0.500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Chromium	ND	*	0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 14:01	1
Cobalt	ND	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Copper	ND	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Iron	0.116	*	0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:01	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Client Sample ID: Rich SWD

Date Collected: 09/13/18 09:30
Date Received: 09/14/18 10:20

Lab Sample ID: 490-159189-1

Matrix: Water

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Lead	ND	*	0.00500	0.00200	mg/L		09/15/18 09:53	09/20/18 14:01	1
Magnesium	**0.457**	**J ***	1.00	0.250	mg/L		09/15/18 09:53	09/20/18 14:01	1
Manganese	**0.00520**	**J ***	0.0150	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Nickel	ND	*	0.0100	0.00300	mg/L		09/15/18 09:53	09/20/18 14:01	1
Potassium	**1.07**	*	1.00	0.500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Selenium	ND	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Silver	ND		0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 14:01	1
Sodium	**36.0**	*	1.00	0.400	mg/L		09/15/18 09:53	09/20/18 14:01	1
Thallium	ND	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:01	1
Vanadium	ND	*	0.0200	0.0100	mg/L		09/15/18 09:53	09/20/18 14:01	1
Zinc	ND	*	0.0500	0.0250	mg/L		09/15/18 09:53	09/20/18 14:01	1

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	**34.3**		10.0	5.00	mg/L			09/23/18 11:31	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	**2.68**		0.100	0.0500	mg/L		09/17/18 08:56	09/20/18 17:57	1
Bicarbonate Alkalinity as CaCO3	**125**		10.0	5.00	mg/L			09/18/18 15:47	1
Alkalinity	**125**		10.0	5.00	mg/L			09/18/18 15:47	1
Total Dissolved Solids	**136000**		1000	700	mg/L			09/18/18 20:15	1
pH	**7.1**	**HF**	0.1	0.1	SU			09/22/18 17:38	1
Total Organic Carbon	**157**		5.00	2.50	mg/L			09/15/18 16:14	5

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	-76.1	U	199	199		192	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Actinium-228	**165**		37.0	40.4		16.8	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Bismuth-212	27.7	U	163	163		283	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Bismuth-214	**273**		39.5	48.1		27.0	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Lead-210	-251	U	192	198		334	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Lead-212	**38.3**		14.5	15.3		20.0	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Lead-214	**296**		32.3	44.5		27.8	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Potassium-40	**391**		178	182		185	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Protactinium-231	136	U	461	461		1020	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Radium-226	**677**		242	268	350	290	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Radium-228	**165**		37.0	40.4		16.8	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Thallium-208	0.555	U	1.67	1.67		18.6	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Thorium-232	**165**		37.0	40.4		16.8	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Thorium-234	-91.1	U	197	197		334	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Uranium-235	-16.0	U	37.3	37.4		140	pCi/L	09/16/18 22:55	09/18/18 13:12	1
Uranium-238	-91.1	U	197	197		334	pCi/L	09/16/18 22:55	09/18/18 13:12	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/16/18 22:55*	*09/18/18 13:12*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Client Sample ID: Rich SWD

Date Collected: 09/13/18 09:30
Date Received: 09/14/18 10:20

Lab Sample ID: 490-159189-1

Matrix: Water

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	701	U G	618	624	3.00	962	pCi/L	09/18/18 09:54	09/20/18 13:40	1
Gross Beta	-40.5	U G	235	235	4.00	416	pCi/L	09/18/18 09:54	09/20/18 13:40	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Client Sample ID: Trip Blank

Lab Sample ID: 490-159189-2

Date Collected: 09/13/18 00:01
Date Received: 09/14/18 10:20

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/15/18 02:59	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/15/18 02:59	1
Toluene	ND		1.00	0.170	ug/L			09/15/18 02:59	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/15/18 02:59	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*119*		*70 - 130*		*09/15/18 02:59*	*1*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*		*09/15/18 02:59*	*1*
Dibromofluoromethane (Surr)	*115*		*70 - 130*		*09/15/18 02:59*	*1*
Toluene-d8 (Surr)	*99*		*70 - 130*		*09/15/18 02:59*	*1*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-542916/6
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/15/18 02:05	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/15/18 02:05	1
Toluene	ND		1.00	0.170	ug/L			09/15/18 02:05	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/15/18 02:05	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*118*		*70 - 130*		*09/15/18 02:05*	*1*
4-Bromofluorobenzene (Surr)	*96*		*70 - 130*		*09/15/18 02:05*	*1*
Dibromofluoromethane (Surr)	*111*		*70 - 130*		*09/15/18 02:05*	*1*
Toluene-d8 (Surr)	*98*		*70 - 130*		*09/15/18 02:05*	*1*

Lab Sample ID: LCS 490-542916/3
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	23.00		ug/L		115	70 - 130
Ethylbenzene	20.0	22.79		ug/L		114	70 - 130
Toluene	20.0	22.64		ug/L		113	70 - 130
Xylenes, Total	40.0	45.73		ug/L		114	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*121*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*101*		*70 - 130*
Toluene-d8 (Surr)	*98*		*70 - 130*

Lab Sample ID: LCSD 490-542916/4
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	24.12		ug/L		121	70 - 130	5	12
Ethylbenzene	20.0	22.98		ug/L		115	70 - 130	1	12
Toluene	20.0	23.44		ug/L		117	70 - 130	3	13
Xylenes, Total	40.0	46.00		ug/L		115	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*120*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*102*		*70 - 130*
Toluene-d8 (Surr)	*100*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-159197-B-1 MSD
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	25.94		ug/L		130	55 - 147	5	22
Ethylbenzene	ND		20.0	24.95		ug/L		125	65 - 139	10	18
Toluene	ND		20.0	24.87		ug/L		124	64 - 136	7	18
Xylenes, Total	ND		40.0	49.20		ug/L		123	69 - 132	10	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*124*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*103*		*70 - 130*
Toluene-d8 (Surr)	*97*		*70 - 130*

Lab Sample ID: 490-159197-C-1 MS
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	24.69		ug/L		123	55 - 147
Ethylbenzene	ND		20.0	22.53		ug/L		113	65 - 139
Toluene	ND		20.0	23.22		ug/L		116	64 - 136
Xylenes, Total	ND		40.0	44.37		ug/L		111	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*123*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*105*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Lab Sample ID: MB 490-545894/6
Matrix: Water
Analysis Batch: 545894

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/27/18 14:34	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/27/18 14:34	1
Toluene	ND		1.00	0.170	ug/L			09/27/18 14:34	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/27/18 14:34	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*		*09/27/18 14:34*	*1*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*		*09/27/18 14:34*	*1*
Dibromofluoromethane (Surr)	*101*		*70 - 130*		*09/27/18 14:34*	*1*
Toluene-d8 (Surr)	*98*		*70 - 130*		*09/27/18 14:34*	*1*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: LCS 490-545894/3
Matrix: Water
Analysis Batch: 545894

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	20.60		ug/L		103	70 - 130
Ethylbenzene	20.0	17.69		ug/L		88	70 - 130
Toluene	20.0	18.66		ug/L		93	70 - 130
Xylenes, Total	40.0	34.49		ug/L		86	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*105*		*70 - 130*
4-Bromofluorobenzene (Surr)	*102*		*70 - 130*
Dibromofluoromethane (Surr)	*96*		*70 - 130*
Toluene-d8 (Surr)	*99*		*70 - 130*

Lab Sample ID: LCSD 490-545894/4
Matrix: Water
Analysis Batch: 545894

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	20.50		ug/L		102	70 - 130	1	12
Ethylbenzene	20.0	17.75		ug/L		89	70 - 130	0	12
Toluene	20.0	18.64		ug/L		93	70 - 130	0	13
Xylenes, Total	40.0	34.78		ug/L		87	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*104*		*70 - 130*
4-Bromofluorobenzene (Surr)	*101*		*70 - 130*
Dibromofluoromethane (Surr)	*96*		*70 - 130*
Toluene-d8 (Surr)	*98*		*70 - 130*

Lab Sample ID: 280-114677-E-2 MS
Matrix: Water
Analysis Batch: 545894

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	21.50		ug/L		108	55 - 147
Ethylbenzene	ND		20.0	18.38		ug/L		92	65 - 139
Toluene	ND		20.0	19.08		ug/L		95	64 - 136
Xylenes, Total	ND		40.0	35.29		ug/L		88	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*103*		*70 - 130*
4-Bromofluorobenzene (Surr)	*100*		*70 - 130*
Dibromofluoromethane (Surr)	*96*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 280-114677-F-2 MSD
Matrix: Water
Analysis Batch: 545894

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	22.40		ug/L		112	55 - 147	4	22
Ethylbenzene	ND		20.0	18.84		ug/L		94	65 - 139	2	18
Toluene	ND		20.0	19.62		ug/L		98	64 - 136	3	18
Xylenes, Total	ND		40.0	36.67		ug/L		92	69 - 132	4	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*107*		*70 - 130*
4-Bromofluorobenzene (Surr)	*100*		*70 - 130*
Dibromofluoromethane (Surr)	*96*		*70 - 130*
Toluene-d8 (Surr)	*97*		*70 - 130*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-543592/8
Matrix: Water
Analysis Batch: 543592

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			09/18/18 11:20	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*104*		*70 - 130*		*09/18/18 11:20*	*1*

Lab Sample ID: LCS 490-543592/7
Matrix: Water
Analysis Batch: 543592

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
C6-C10 OK			200	215.5		ug/L		108	80 - 120		

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*104*		*70 - 130*

Lab Sample ID: LCSD 490-543592/20
Matrix: Water
Analysis Batch: 543592

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK			200	210.4		ug/L		105	80 - 120	2	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*103*		*70 - 130*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-544103/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544357 — **Prep Batch: 544103**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		09/20/18 08:29	09/20/18 23:37	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*91*		*50 - 150*	*09/20/18 08:29*	*09/20/18 23:37*	*1*

Lab Sample ID: LCS 490-544103/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544357 — **Prep Batch: 544103**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	497.2		ug/L		99	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*109*		*50 - 150*

Lab Sample ID: LCSD 490-544103/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544357 — **Prep Batch: 544103**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28	500	500.9		ug/L		100	80 - 120	1	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*108*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-542925/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	ND		1.00	0.700	mg/L			09/14/18 21:52	1
Fluoride	ND		0.100	0.0600	mg/L			09/14/18 21:52	1
Sulfate	ND		1.00	0.600	mg/L			09/14/18 21:52	1

Lab Sample ID: LCS 490-542925/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Chloride	10.0	9.580		mg/L		96	90 - 110
Fluoride	1.00	0.9829		mg/L		98	90 - 110
Sulfate	10.0	9.417		mg/L		94	90 - 110

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-542925/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride			10.0	9.591		mg/L		96	90 - 110	0	20
Fluoride			1.00	1.025		mg/L		102	90 - 110	4	20
Sulfate			10.0	9.547		mg/L		95	90 - 110	1	20

Lab Sample ID: 490-159206-E-6 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Bromide	0.594	J *	10.0	8.810		mg/L		82	80 - 120		
Chloride	37.8		10.0	45.89	E	mg/L		80	80 - 120		
Fluoride	0.137		1.00	1.055		mg/L		92	80 - 120		
Sulfate	14.6		10.0	24.32		mg/L		97	80 - 120		

Lab Sample ID: 490-159206-E-6 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	0.594	J *	10.0	8.839		mg/L		82	80 - 120	0	20
Chloride	37.8		10.0	45.93	E	mg/L		81	80 - 120	0	20
Fluoride	0.137		1.00	1.067		mg/L		93	80 - 120	1	20
Sulfate	14.6		10.0	24.38		mg/L		98	80 - 120	0	20

Lab Sample ID: MB 490-544169/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			09/20/18 10:00	1
Chloride	ND		1.00	0.700	mg/L			09/20/18 10:00	1
Fluoride	ND		0.100	0.0600	mg/L			09/20/18 10:00	1
Sulfate	ND		1.00	0.600	mg/L			09/20/18 10:00	1

Lab Sample ID: LCS 490-544169/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Bromide			10.0	9.681		mg/L		97	90 - 110		
Chloride			10.0	9.822		mg/L		98	90 - 110		
Sulfate			10.0	9.597		mg/L		96	90 - 110		

Lab Sample ID: LCSD 490-544169/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide			10.0	9.694		mg/L		97	90 - 110	0	20

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: LCSD 490-544169/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride			10.0	9.854		mg/L		98	90 - 110	0	20
Fluoride			1.00	0.9109		mg/L		91	90 - 110	2	20
Sulfate			10.0	9.764		mg/L		97	90 - 110	2	20

Lab Sample ID: 490-159182-J-11 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Bromide	5.53		10.0	17.19		mg/L		116	80 - 120		
Chloride	125	E	10.0	137.5	E 4	mg/L		123	80 - 120		
Fluoride	0.228	*	1.00	1.296		mg/L		107	80 - 120		
Sulfate	12.5	F1	10.0	25.12	F1	mg/L		125	80 - 120		

Lab Sample ID: 490-159182-J-11 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	5.53		10.0	16.48		mg/L		109	80 - 120	4	20
Chloride	125	E	10.0	137.9	E 4	mg/L		126	80 - 120	0	20
Fluoride	0.228	*	1.00	1.228		mg/L		100	80 - 120	5	20
Sulfate	12.5	F1	10.0	24.44		mg/L		119	80 - 120	3	20

Lab Sample ID: MB 490-544170/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			09/20/18 10:00	1
Nitrite as N	ND		0.100	0.0500	mg/L			09/20/18 10:00	1

Lab Sample ID: LCS 490-544170/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Nitrate as N			1.00	0.9557		mg/L		96	90 - 110		
Nitrite as N			1.00	0.9140		mg/L		91	90 - 110		

Lab Sample ID: LCSD 490-544170/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N			1.00	0.9534		mg/L		95	90 - 110	0	20
Nitrite as N			1.00	0.9123		mg/L		91	90 - 110	0	20

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: 490-159182-J-11 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	0.141	F1	1.00	1.400	F1	mg/L		126	80 - 120
Nitrite as N	ND	F1	1.00	0.7019	F1	mg/L		70	80 - 120

Lab Sample ID: 490-159182-J-11 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	0.141	F1	1.00	1.340		mg/L		120	80 - 120	4	20
Nitrite as N	ND	F1	1.00	0.6638	F1	mg/L		66	80 - 120	6	20

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-542965/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544281 — **Prep Batch: 542965**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Antimony	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Arsenic	ND		0.0100	0.00860	mg/L		09/15/18 09:53	09/20/18 13:33	1
Barium	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Beryllium	ND		0.00400	0.00200	mg/L		09/15/18 09:53	09/20/18 13:33	1
Cadmium	ND		0.00100	0.000500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Calcium	ND		1.00	0.500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Chromium	ND		0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 13:33	1
Cobalt	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Copper	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Iron	ND		0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Lead	ND		0.00500	0.00200	mg/L		09/15/18 09:53	09/20/18 13:33	1
Magnesium	ND		1.00	0.250	mg/L		09/15/18 09:53	09/20/18 13:33	1
Manganese	ND		0.0150	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Nickel	ND		0.0100	0.00300	mg/L		09/15/18 09:53	09/20/18 13:33	1
Potassium	ND		1.00	0.500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Selenium	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Silver	ND		0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 13:33	1
Sodium	ND		1.00	0.400	mg/L		09/15/18 09:53	09/20/18 13:33	1
Thallium	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Vanadium	ND		0.0200	0.0100	mg/L		09/15/18 09:53	09/20/18 13:33	1
Zinc	ND		0.0500	0.0250	mg/L		09/15/18 09:53	09/20/18 13:33	1

Lab Sample ID: LCS 490-542965/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544281 — **Prep Batch: 542965**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.017		mg/L		102	85 - 115
Antimony	0.100	0.1049		mg/L		105	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-542965/2-A
Matrix: Water
Analysis Batch: 544281

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 542965

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Arsenic	0.100	0.09990		mg/L		100	85 - 115
Barium	0.100	0.1032		mg/L		103	85 - 115
Beryllium	0.100	0.09920		mg/L		99	85 - 115
Cadmium	0.100	0.1089		mg/L		109	85 - 115
Calcium	10.0	9.676		mg/L		97	85 - 115
Chromium	0.100	0.1024		mg/L		102	85 - 115
Cobalt	0.100	0.1039		mg/L		104	85 - 115
Copper	0.100	0.09970		mg/L		100	85 - 115
Iron	1.00	0.9801		mg/L		98	85 - 115
Lead	0.100	0.09940		mg/L		99	85 - 115
Magnesium	10.0	10.12		mg/L		101	85 - 115
Manganese	0.100	0.09760		mg/L		98	85 - 115
Nickel	0.100	0.1021		mg/L		102	85 - 115
Potassium	10.0	9.842		mg/L		98	85 - 115
Selenium	0.100	0.1131		mg/L		113	85 - 115
Silver	0.100	0.08940		mg/L		89	85 - 115
Sodium	10.0	9.488		mg/L		95	85 - 115
Thallium	0.100	0.1037		mg/L		104	85 - 115
Vanadium	0.100	0.1051		mg/L		105	85 - 115
Zinc	0.100	0.1150		mg/L		115	85 - 115

Lab Sample ID: LCSD 490-542965/3-A
Matrix: Water
Analysis Batch: 544281

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA
Prep Batch: 542965

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	2.00	2.093	*	mg/L		105	85 - 115	69	20
Antimony	0.100	0.1093		mg/L		109	85 - 115	4	20
Arsenic	0.200	0.2108	*	mg/L		105	85 - 115	71	20
Barium	0.200	0.2138	*	mg/L		107	85 - 115	70	20
Beryllium	0.200	0.2056	*	mg/L		103	85 - 115	70	20
Cadmium	0.200	0.2243	*	mg/L		112	85 - 115	69	20
Calcium	20.0	20.75	*	mg/L		104	85 - 115	73	20
Chromium	0.200	0.2114	*	mg/L		106	85 - 115	69	20
Cobalt	0.200	0.2127	*	mg/L		106	85 - 115	69	20
Copper	0.200	0.2057	*	mg/L		103	85 - 115	69	20
Iron	2.00	2.022	*	mg/L		101	85 - 115	69	20
Lead	0.200	0.2042	*	mg/L		102	85 - 115	69	20
Magnesium	20.0	20.79	*	mg/L		104	85 - 115	69	20
Manganese	0.200	0.1996	*	mg/L		100	85 - 115	69	20
Nickel	0.200	0.2093	*	mg/L		105	85 - 115	69	20
Potassium	20.0	20.42	*	mg/L		102	85 - 115	70	20
Selenium	0.200	0.2300	*	mg/L		115	85 - 115	68	20
Silver	0.100	0.09060		mg/L		91	85 - 115	1	20
Sodium	20.0	19.56	*	mg/L		98	85 - 115	69	20
Thallium	0.200	0.2120	*	mg/L		106	85 - 115	69	20
Vanadium	0.200	0.2138	*	mg/L		107	85 - 115	68	20
Zinc	0.200	0.2355	*	mg/L		118	85 - 115	69	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-543181/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/17/18 08:56	09/20/18 17:54	1

Lab Sample ID: LCS 490-543181/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	1.880		mg/L		94	90 - 110

Lab Sample ID: LCSD 490-543181/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.00	1.840		mg/L		92	90 - 110	2	20

Lab Sample ID: 490-159219-A-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.93		2.00	4.990		mg/L		103	73 - 119

Lab Sample ID: 490-159219-A-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.93		2.00	4.830		mg/L		95	73 - 119	3	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-543924/29 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			09/18/18 15:07	1
Alkalinity	ND		10.0	5.00	mg/L			09/18/18 15:07	1

Lab Sample ID: LCS 490-543924/30 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Alkalinity	100	95.76		mg/L		96	90 - 110

Method: SM 2320B - Alkalinity (Continued)

Lab Sample ID: LCSD 490-543924/52 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity			100	98.27		mg/L		98	90 - 110	3	20

Lab Sample ID: 490-159198-J-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	167			167.0		mg/L				0.2	20
Alkalinity	167			167.0		mg/L				0.2	20

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-543706/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			09/18/18 20:15	1

Lab Sample ID: LCS 490-543706/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Total Dissolved Solids			100	104.0		mg/L		104	90 - 110		

Lab Sample ID: 490-159200-H-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	592			576.0		mg/L				3	20

Lab Sample ID: 590-9365-E-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Total Dissolved Solids	90.0			110.0		mg/L				20	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-159113-E-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544827

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
pH	8.4			8.4		SU				0	20

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: MB 490-543099/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			09/15/18 13:49	1

Lab Sample ID: LCS 490-543099/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	10.0	9.913		mg/L		99	90 - 110

Lab Sample ID: 490-159137-A-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	14.0		40.0	60.39		mg/L		116	74 - 134

Lab Sample ID: 490-159137-A-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	14.0		40.0	60.30		mg/L		116	74 - 134	0	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-389656/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 389815 — **Prep Batch: 389656**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	-16.45	U	32.6	32.6		121	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Actinium-228	9.426	U	18.5	18.5		41.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Bismuth-212	-48.91	U	129	129		221	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Bismuth-214	-28.43	U	17.7	17.9		67.7	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Lead-210	35.85	U	132	132		200	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Lead-212	-3.925	U	15.5	15.5		26.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Lead-214	-5.502	U	16.5	16.5		29.2	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Potassium-40	-71.97	U	136	136		195	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Protactinium-231	87.82	U	224	225		516	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Radium-226	268.5		152	158	350	171	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Radium-228	9.426	U	18.5	18.5		41.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Thallium-208	1.069	U	4.00	4.00		10.6	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Thorium-232	9.426	U	18.5	18.5		41.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Thorium-234	26.12	U	80.8	80.9		140	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Uranium-235	14.40	U	48.9	48.9		82.1	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Uranium-238	26.12	U	80.8	80.9		140	pCi/L	09/16/18 22:55	09/17/18 10:04	1

Other Detected Radionuclides	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Other Detected Radionuclide	None						pCi/L	09/16/18 22:55	09/17/18 10:04	1

Lab Sample ID: LCS 160-389656/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 389814 — **Prep Batch: 389656**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Americium-241	136000	133400		15400		502	pCi/L	98	90 - 111
Cesium-137	45300	43680		4390		152	pCi/L	96	90 - 111
Cobalt-60	32300	31230		3100		105	pCi/L	97	89 - 110

Lab Sample ID: 160-30723-F-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 389815 — **Prep Batch: 389656**

Analyte	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Actinium-227	-239	U	41.47	U	71.5		438	pCi/L	0.55	1
Actinium-228	1750		1743		198		111	pCi/L	0.02	1
Bismuth-212	-342	U	571.3	F	300		308	pCi/L	1.14	1
Bismuth-214	3600		4219		444		64.4	pCi/L	0.75	1
Lead-210	-523	U	-39.59	U	441		626	pCi/L	0.67	1
Lead-212	338		334.3		59.7		56.4	pCi/L	0.03	1
Lead-214	4140		4417		471		75.8	pCi/L	0.30	1
Potassium-40	-123	U	323.7	U	316		334	pCi/L	0.63	1
Protactinium-231	-546	U	-402.5	U	1850		3060	pCi/L	0.03	1
Radium-226	14800	G	13280	G	2360	350	922	pCi/L	0.30	1
Radium-228	1750		1743		198		111	pCi/L	0.02	1
Thallium-208	107		106.2		31.9		31.5	pCi/L	0.01	1
Thorium-232	1750		1743		198		111	pCi/L	0.02	1
Thorium-234	133	U	-35.89	U	961		1590	pCi/L	0.11	1
Uranium-235	-7.70	U	66.76	U	222		377	pCi/L	0.08	1
Uranium-238	133	U	-35.89	U	961		1590	pCi/L	0.11	1

Other Detected Radionuclides	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Other Detected Radionuclide	None		None					pCi/L		

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-389969/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.2193	U	0.564	0.564	3.00	1.01	pCi/L	09/18/18 09:54	09/20/18 13:39	1
Gross Beta	0.05579	U	0.557	0.557	4.00	0.977	pCi/L	09/18/18 09:54	09/20/18 13:39	1

Method: 9310 - Gross Alpha / Beta (GFPC) (Continued)

Lab Sample ID: LCS 160-389969/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Alpha	51.0	47.10		6.75	3.00	1.29	pCi/L	92	73 - 133

Lab Sample ID: LCSB 160-389969/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Beta	87.7	86.33		9.16	4.00	0.979	pCi/L	98	75 - 125

Lab Sample ID: 160-30328-A-15-C MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Alpha	3.25	G	112	116.9		16.8	3.00	3.67	pCi/L	101	60 - 140

Lab Sample ID: 160-30328-A-15-D MSBT — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Gross Beta	7.57		193	199.9		21.2	4.00	2.41	pCi/L	100	60 - 140

Lab Sample ID: 160-30328-A-15-E DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	Sample Result	Sample Qual	DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	RER	RER Limit
Gross Alpha	3.25	G	6.881	G	3.65	3.00	4.90	pCi/L	0.61	1
Gross Beta	7.57		10.17		2.33	4.00	2.39	pCi/L	0.58	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

GC/MS VOA

Analysis Batch: 542916

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	8260B	
490-159189-2	Trip Blank	Total/NA	Water	8260B	
MB 490-542916/6	Method Blank	Total/NA	Water	8260B	
LCS 490-542916/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-542916/4	Lab Control Sample Dup	Total/NA	Water	8260B	
490-159197-B-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	
490-159197-C-1 MS	Matrix Spike	Total/NA	Water	8260B	

Analysis Batch: 545894

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	8260B	
MB 490-545894/6	Method Blank	Total/NA	Water	8260B	
LCS 490-545894/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-545894/4	Lab Control Sample Dup	Total/NA	Water	8260B	
280-114677-E-2 MS	Matrix Spike	Total/NA	Water	8260B	
280-114677-F-2 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 543592

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	OK GRO	
MB 490-543592/8	Method Blank	Total/NA	Water	OK GRO	
LCS 490-543592/7	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-543592/20	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 544103

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	3510C	
MB 490-544103/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-544103/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-544103/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 544357

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-544103/1-A	Method Blank	Total/NA	Water	OK DRO	544103
LCS 490-544103/2-A	Lab Control Sample	Total/NA	Water	OK DRO	544103
LCSD 490-544103/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	544103

Analysis Batch: 544512

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	OK DRO	544103

HPLC/IC

Analysis Batch: 542925

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	300.0	

HPLC/IC (Continued)

Analysis Batch: 542925 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-542925/3	Method Blank	Total/NA	Water	300.0	
LCS 490-542925/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-542925/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-159206-E-6 MS	Matrix Spike	Total/NA	Water	300.0	
490-159206-E-6 MSD	Matrix Spike Duplicate	Total/NA	Water	300.0	

Analysis Batch: 544169

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	300.0	
490-159189-1	Rich SWD	Total/NA	Water	300.0	
MB 490-544169/3	Method Blank	Total/NA	Water	300.0	
LCS 490-544169/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-544169/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-159182-J-11 MS	Matrix Spike	Total/NA	Water	300.0	
490-159182-J-11 MSD	Matrix Spike Duplicate	Total/NA	Water	300.0	

Analysis Batch: 544170

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	300.0	
MB 490-544170/3	Method Blank	Total/NA	Water	300.0	
LCS 490-544170/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-544170/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-159182-J-11 MS	Matrix Spike	Total/NA	Water	300.0	
490-159182-J-11 MSD	Matrix Spike Duplicate	Total/NA	Water	300.0	

Metals

Prep Batch: 542965

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	200.7	
MB 490-542965/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-542965/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-542965/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	

Analysis Batch: 544281

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	200.7 Rev 4.4	542965
MB 490-542965/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	542965
LCS 490-542965/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	542965
LCSD 490-542965/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	542965

Analysis Batch: 544886

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	SM 2340B	

General Chemistry

Analysis Batch: 543099

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	SM 5310B	

General Chemistry (Continued)

Analysis Batch: 543099 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-543099/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-543099/6	Lab Control Sample	Total/NA	Water	SM 5310B	
490-159137-A-1 MS	Matrix Spike	Total/NA	Water	SM 5310B	
490-159137-A-1 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

Prep Batch: 543181

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	365.2/365.3/365	
MB 490-543181/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-543181/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-543181/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-159219-A-1-B MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-159219-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 543706

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	SM 2540C	
MB 490-543706/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-543706/2	Lab Control Sample	Total/NA	Water	SM 2540C	
490-159200-H-1 DU	Duplicate	Total/NA	Water	SM 2540C	
590-9365-E-1 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 543924

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	SM 2320B	
MB 490-543924/29	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-543924/30	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-543924/52	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-159198-J-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Analysis Batch: 544073

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	365.4	543181
MB 490-543181/1-A	Method Blank	Total/NA	Water	365.4	543181
LCS 490-543181/2-A	Lab Control Sample	Total/NA	Water	365.4	543181
LCSD 490-543181/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	543181
490-159219-A-1-B MS	Matrix Spike	Total/NA	Water	365.4	543181
490-159219-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	543181

Analysis Batch: 544827

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	SM 4500 H+ B	
LCS 490-544827/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-159113-E-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Rad

Prep Batch: 389656

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	Fill_Geo-0	

Rad (Continued)

Prep Batch: 389656 (Continued)

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 160-389656/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-389656/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
160-30723-F-1-B DU	Duplicate	Total/NA	Water	Fill_Geo-0	

Prep Batch: 389969

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159189-1	Rich SWD	Total/NA	Water	Evaporation	
MB 160-389969/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-389969/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-389969/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
160-30328-A-15-C MS	Matrix Spike	Total/NA	Water	Evaporation	
160-30328-A-15-D MSBT	Matrix Spike	Total/NA	Water	Evaporation	
160-30328-A-15-E DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Client Sample ID: Rich SWD

Lab Sample ID: 490-159189-1
Matrix: Water

Date Collected: 09/13/18 09:30
Date Received: 09/14/18 10:20

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		10	10 mL	10 mL	542916	09/15/18 09:22	AK1	TAL NSH
Total/NA	Analysis	8260B		25	10 mL	10 mL	545894	09/27/18 22:43	AK1	TAL NSH
Total/NA	Analysis	OK GRO		10	5 mL	5 mL	543592	09/18/18 14:45	GWM	TAL NSH
Total/NA	Prep	3510C			1138.5 mL	1 mL	544103	09/20/18 08:30	TJB	TAL NSH
Total/NA	Analysis	OK DRO		20			544512	09/21/18 15:21	JDJ	TAL NSH
Total/NA	Analysis	300.0		20			542925	09/15/18 00:34	SW1	TAL NSH
Total/NA	Analysis	300.0		200			544169	09/20/18 11:56	SW1	TAL NSH
Total/NA	Analysis	300.0		200			544170	09/20/18 11:56	SW1	TAL NSH
Total/NA	Analysis	300.0		5000			544169	09/20/18 12:08	SW1	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	542965	09/15/18 09:53	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			544281	09/20/18 14:01	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			544886	09/23/18 11:31	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	543181	09/17/18 08:56	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	544073	09/20/18 17:57	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	543924	09/18/18 15:47	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	543706	09/18/18 20:15	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			544827	09/22/18 17:38	MXX	TAL NSH
Total/NA	Analysis	SM 5310B		5	50 mL	50 mL	543099	09/15/18 16:14	CLJ	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	389656	09/16/18 22:55	SJS	TAL SL
Total/NA	Analysis	901.1		1			389996	09/18/18 13:12	CDR	TAL SL
Total/NA	Prep	Evaporation			0.5 mL	1.0 g	389969	09/18/18 09:54	MRB	TAL SL
Total/NA	Analysis	9310		1			390511	09/20/18 13:40	RTM	TAL SL

Client Sample ID: Trip Blank

Lab Sample ID: 490-159189-2
Matrix: Water

Date Collected: 09/13/18 00:01
Date Received: 09/14/18 10:20

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	10 mL	10 mL	542916	09/15/18 02:59	AK1	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159189-1
SDG: Rich SWD

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-19
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-19
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-19
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-19
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-19
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-19
Nevada	State Program	9	MO000542018-1	07-31-19
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-19
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-19
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-19
West Virginia DEP	State Program	3	381	10-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-159189 Chain of Custody

Cooler Received/Opened On 9/14/2018 @ 10:20

Time Samples Removed From Cooler 12:20 Time Samples Placed In Storage 12:40 (2 Hour Window)

1. Tracking # 8180 (last 4 digits, FedEx) Courier: FedEx

   IR Gun ID 17960358 pH Strip Lot HC849161 Chlorine Strip Lot 040518K

2. Temperature of rep. sample or temp blank when opened: 4.1 *Degrees Celsius*

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 front

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) [signature]

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #_____

I certify that I unloaded the cooler and answered questions 7-14 (intial) KD

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) KD

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) KD

I certify that I attached a label with the unique LIMS number to each container (intial) KD

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information

Client Contact: Dr. James Rosenblum
Company: CH2M Hill, Inc.
Address: 12377 Merit Drive Suite 1000
City: Dallas
State, Zip: TX, 75251
Phone: 248-939-3216(Tel)
Email: james.rosenblum@ch2m.com
Project Name: OWRB Study Phase II
Site: Rich SWD

Sampler: Jarrod Maly
Phone: 580 541 0319

Lab PM: Gambill, Jennifer
E-Mail: jennifer.gambill@testamericainc.com

Carrier Tracking No(s):

COC No:
Page: Page of
Job #:

Due Date Requested:
TAT Requested (days):
PO #:
WO #:
Project #: 49013620
SSOW#:

Analysis Requested

Preservation Codes:
A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA
M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)
Other:

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	9-13	930A	G	W																	
Gross Alpha/Beta (1)	9-13	930A	G	W																	
Alk/IC/pH (3)	9-13	930A	G	W																	
Metals/Hardness (1)	9-13	930A	G	W																	
TOC (1)	9-13	930A	G	W																	
BTEX/GRO (6)	9-13	930A	G	W																	
TDS (1)	9-13	930A	G	W																	
DRO (2)	9-13	930A	G	W																	
phosphorus (1)	9-13	930A	G	W																	
			G	W																	

Loc: 490
159189

Possible Hazard Identification: ☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month): ☐ Return To Client ☐ Disposal By Lab ☐ Archive For ____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: Owen Mills Date: 8-8-18 Time: 10:52 Method of Shipment: Hand delivered

Relinquished by	Date/Time	Company	Received by	Date/Time	Company
D&B Jarrod Maly	9-13-18	D&B	Fed Ex		
			[signature]	09-14-2018 10:20	TA-NAS

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 4.1

Ver: 08/04/2016

TestAmerica

THE LEADER IN ENVIRONMENTAL TESTING

ANALYTICAL REPORT

TestAmerica Laboratories, Inc.
TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Tel: (615)726-0177

TestAmerica Job ID: 490-159194-1
TestAmerica SDG: Woods County Lower OSage
Client Project/Site: OWRB Study Phase II

For:
CH2M Hill, Inc.
12377 Merit Drive
Suite 1000
Dallas, Texas 75251

Attn: Mr. Michael Dunkel

Jennifer Gambill

Authorized for release by:
9/28/2018 7:01:13 PM

Jennifer Gambill, Project Manager I
(615)301-5044
jennifer.gambill@testamericainc.com

The test results in this report meet all 2003 NELAC and 2009 TNI requirements for accredited parameters, exceptions are noted in this report. This report may not be reproduced except in full, and with written approval from the laboratory. For questions please contact the Project Manager at the e-mail address or telephone number listed on this page.

This report has been electronically signed and authorized by the signatory. Electronic signature is intended to be the legally binding equivalent of a traditionally handwritten signature.

Results relate only to the items tested and the sample(s) as received by the laboratory.

Table of Contents

Sample Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Lab Sample ID	Client Sample ID	Matrix	Collected	Received
490-159194-1	Woods County Lower OSage	Water	09/13/18 10:30	09/14/18 10:20
490-159194-2	Trip Blank	Water	09/13/18 00:01	09/14/18 10:20

Job ID: 490-159194-1

Laboratory: TestAmerica Nashville

Narrative

Job Narrative
490-159194-1

Comments
No additional comments.

Receipt
The samples were received on 9/14/2018 10:20 AM; the samples arrived in good condition, properly preserved and, where required, on ice. The temperature of the cooler at receipt was 12.4º C which is outside the required temperature criteria.

HPLC/IC
Method(s) 300.0: The following sample was diluted due to the nature of the sample matrix: Woods County Lower OSage (490-159194-1). Elevated reporting limits (RLs) are provided.

Method(s) 300.0: The matrix spike / matrix spike duplicate (MS/MSD) results for 490-542925 exceeded the calibration curve limit for chloride. (490-159206-E-6 MS) and (490-159206-E-6 MSD)

Method(s) 300.0: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-544169 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Method(s) 300.0: The method blank for analytical batch 490-544169 contained Bromide above the method detection limit. This target analyte concentration was less than half the reporting limit (1/2RL); therefore, re-extraction and re-analysis of samples was not performed.

Method(s) 300.0: The matrix spike / matrix spike duplicate (MS/MSD) recoveries for analytical batch 490-544170 were outside control limits. Sample matrix interference and/or non-homogeneity are suspected because the associated laboratory control sample (LCS) recovery was within acceptance limits.

Method(s) 300.0: Reanalysis of the following sample was performed outside of the analytical holding time due to samples matrix as well as failing QC : Woods County Lower OSage (490-159194-1).

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

GC Semi VOA
Method(s) OK DRO: Insufficient sample volume was available to perform a matrix spike/matrix spike duplicate (MS/MSD) associated with preparation batch 490-544103 and analytical batch 490-544357.

Method(s) OK DRO: The following sample was diluted to bring the concentration of target analytes within the calibration range: Woods County Lower OSage (490-159194-1). Elevated reporting limits (RLs) are provided.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Metals
Method(s) 200.7 Rev 4.4: The RPD of the laboratory control sample (LCS) and laboratory control sample duplicate (LCSD) for batch preparation batch 490-542965 and analytical batch 490-543594 recovered outside control limits for the following analytes: Aluminum, Arsenic, Barium, Chromium, Lead, Selenium, Silver, Antimony, Beryllium, Cadmium, Calcium, Cobalt, Copper, Iron, Potassium, Magnesium, Manganese, Sodium, Nickel, Thallium, Vanadium and Zinc .

Method(s) 200.7 Rev 4.4: The RPD of the laboratory control sample (LCS) and laboratory control sample duplicate (LCSD) for batch preparation batch 490-542965 and analytical batch 490-544892 recovered outside control limits for the following analyte: Sodium.

Method(s) 200.7 Rev 4.4: Internal Standard (IS) is within laboratory requirements of 60-140%: (CCB 490-544892/64) and (CCV 490-544892/63).

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Job ID: 490-159194-1 (Continued)

Laboratory: TestAmerica Nashville (Continued)

General Chemistry
Method(s) SM 2540C: The minimum analysis volume of 1 mL was used for the following sample which produced a base result greater than 200mg before calculation of the final result: Woods County Lower OSage (490-159194-1). The reference method specifies that no more than 200mg of weight be recovered for a chosen sample analysis volume in order to produce the best data precision. As such, the data has been qualified.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Narrative

RAD
Method(s) 901.1: Gamma Prep Batch: 160-389656: The following samples, analyzed by gamma spectroscopy, did not meet the Ra-226 detection goal due to high concentrations of the analyte: (LCS 160-389656/2-A), (MB 160-389656/1-A), (160-30723-F-1-A) and (160-30723-F-1-B DU). The data have been reported.

Method(s) 901.1: Gamma Prep Batch 160-389656: Ra-226 by gamma spectroscopy is typically determined by inference from daughters (e.g. Bi-214) after sealing the sample in an appropriate counting geometry/container and waiting 21 days to allow the Ra-226 decay chain through Rn-222 to reach secular equilibrium. Such an approach is considered to be the most reliable and representative means for establishing the true Ra-226 concentration in the sample. The method requested by the client to report Ra-226, using its own 186 keV gamma-ray emission, is subject to interference and potential bias due to the 185.7 keV U-235 gamma ray. Experience also indicates gamma spectroscopy software does not consistently assign accurate peak areas to Ra-226 (186 keV), with the problem compounded by slight drift of the instrumentation. The laboratory considers Ra-226 reported based upon the 186 keV gamma-ray emission to be best used by the client in a qualitative fashion.
The following samples were affected: Woods County Lower OSage (490-159194-1), (LCS 160-389656/2-A), (MB 160-389656/1-A), (160-30723-F-1-A) and (160-30723-F-1-B DU).

Method(s) 901.1: Gamma Prep Batch 160-389656: The following samples, analyzed by gamma spectroscopy, have lead-210 as a requested analyte: Woods County Lower OSage (490-159194-1), (LCS 160-389656/2-A), (MB 160-389656/1-A), (160-30723-F-1-A) and (160-30723-F-1-B DU). Lead-210, energy 46.54 keV, is out of calibration range for water and Density-equals-one geometries. The results are estimated. The data have been reported with this narrative.

Method(s) 9310: Gamma Prep Batch 160-389969: The gross alpha detection goal was not met for the following samples due to a reduction of the sample size attributed to high residual mass: (160-30328-A-15-B) and (160-30328-A-15-E DU). Analytical results are reported with the detection limit achieved.

Method(s) 9310: Gamma Prep Batch 160-389969: The gross alpha and gross beta detection goals were not met for the following samples due to a reduction of the sample size attributed to high residual mass: Woods County Lower OSage (490-159194-1). Analytical results are reported with the detection limit achieved.

Method(s) Evaporation: Gross Alpha/Beta preparation batch 160-389969: The following samples Woods County Lower OSage (490-159194-1) had a final mass above the 100 mg limit. A 1:2 dilution was preformed and is reflected in the initial amount used.

No additional analytical or quality issues were noted, other than those described above or in the Definitions/Glossary page.

Definitions/Glossary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Qualifiers

HPLC/IC

Qualifier	Qualifier Description
4	MS, MSD: The analyte present in the original sample is greater than 4 times the matrix spike concentration; therefore, control limits are not applicable.
E	Result exceeded calibration range.
F1	MS and/or MSD Recovery is outside acceptance limits.
H	Sample was prepped or analyzed beyond the specified holding time

Metals

Qualifier	Qualifier Description
*	RPD of the LCS and LCSD exceeds the control limits
J	Result is less than the RL but greater than or equal to the MDL and the concentration is an approximate value.
*	LCS or LCSD is outside acceptance limits.

General Chemistry

Qualifier	Qualifier Description
E	Result exceeded calibration range.
HF	Field parameter with a holding time of 15 minutes. Test performed by laboratory at client's request.

Rad

Qualifier	Qualifier Description
U	Result is less than the sample detection limit.
G	The Sample MDC is greater than the requested RL.
F	Duplicate RPD exceeds the control limit

Glossary

Abbreviation	These commonly used abbreviations may or may not be present in this report.
¤	Listed under the "D" column to designate that the result is reported on a dry weight basis
%R	Percent Recovery
CFL	Contains Free Liquid
CNF	Contains No Free Liquid
DER	Duplicate Error Ratio (normalized absolute difference)
Dil Fac	Dilution Factor
DL	Detection Limit (DoD/DOE)
DL, RA, RE, IN	Indicates a Dilution, Re-analysis, Re-extraction, or additional Initial metals/anion analysis of the sample
DLC	Decision Level Concentration (Radiochemistry)
EDL	Estimated Detection Limit (Dioxin)
LOD	Limit of Detection (DoD/DOE)
LOQ	Limit of Quantitation (DoD/DOE)
MDA	Minimum Detectable Activity (Radiochemistry)
MDC	Minimum Detectable Concentration (Radiochemistry)
MDL	Method Detection Limit
ML	Minimum Level (Dioxin)
NC	Not Calculated
ND	Not Detected at the reporting limit (or MDL or EDL if shown)
PQL	Practical Quantitation Limit
QC	Quality Control
RER	Relative Error Ratio (Radiochemistry)
RL	Reporting Limit or Requested Limit (Radiochemistry)
RPD	Relative Percent Difference, a measure of the relative difference between two points
TEF	Toxicity Equivalent Factor (Dioxin)
TEQ	Toxicity Equivalent Quotient (Dioxin)

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Client Sample ID: Woods County Lower OSage

Lab Sample ID: 490-159194-1
Date Collected: 09/13/18 10:30
Matrix: Water
Date Received: 09/14/18 10:20

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	2100		10.0	2.00	ug/L			09/20/18 16:43	10
Ethylbenzene	139		10.0	1.90	ug/L			09/20/18 16:43	10
Toluene	1400		10.0	1.70	ug/L			09/20/18 16:43	10
Xylenes, Total	417		30.0	5.80	ug/L			09/20/18 16:43	10

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*		*09/18/18 21:37*	*50*
1,2-Dichloroethane-d4 (Surr)	*116*		*70 - 130*		*09/20/18 16:43*	*10*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*		*09/18/18 21:37*	*50*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*		*09/20/18 16:43*	*10*
Dibromofluoromethane (Surr)	*98*		*70 - 130*		*09/18/18 21:37*	*50*
Dibromofluoromethane (Surr)	*101*		*70 - 130*		*09/20/18 16:43*	*10*
Toluene-d8 (Surr)	*96*		*70 - 130*		*09/18/18 21:37*	*50*
Toluene-d8 (Surr)	*100*		*70 - 130*		*09/20/18 16:43*	*10*

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	4970		200	100	ug/L			09/18/18 15:16	10

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*97*		*70 - 130*		*09/18/18 15:16*	*10*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	4310		426	213	ug/L		09/20/18 08:30	09/21/18 14:58	5

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*106*		*50 - 150*	*09/20/18 08:30*	*09/21/18 14:58*	*5*

Method: 300.0 - Anions, Ion Chromatography

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	1150		200	10.0	mg/L			09/20/18 12:31	200
Nitrate as N	ND	H	20.0	10.0	mg/L			09/20/18 12:31	200
Chloride	142000		5000	3500	mg/L			09/20/18 12:42	5000
Nitrite as N	ND	H	20.0	10.0	mg/L			09/20/18 12:31	200
Fluoride	ND		2.00	1.20	mg/L			09/15/18 01:33	20
Sulfate	369		20.0	12.0	mg/L			09/15/18 01:33	20

Method: 200.7 Rev 4.4 - Metals (ICP)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	0.115	*	0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Antimony	ND		0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:23	10
Arsenic	0.0200	*	0.0100	0.00860	mg/L		09/15/18 09:53	09/20/18 14:17	1
Barium	23.9	*	0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:23	10
Beryllium	ND	*	0.00400	0.00200	mg/L		09/15/18 09:53	09/20/18 14:17	1
Cadmium	0.00270	*	0.00100	0.000500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Calcium	12800	*	100	50.0	mg/L		09/15/18 09:53	09/20/18 14:36	100
Chromium	ND	*	0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 14:17	1
Cobalt	ND	*	0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:23	10
Copper	0.0155	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Iron	17.2	*	0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 14:17	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Client Sample ID: Woods County Lower OSage

Lab Sample ID: 490-159194-1
Date Collected: 09/13/18 10:30
Matrix: Water
Date Received: 09/14/18 10:20

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Lead	0.0316	*	0.00500	0.00200	mg/L		09/15/18 09:53	09/20/18 14:17	1
Magnesium	3170	*	10.0	2.50	mg/L		09/15/18 09:53	09/20/18 14:23	10
Manganese	1.63	*	0.0150	0.00500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Nickel	0.00800	J *	0.0100	0.00300	mg/L		09/15/18 09:53	09/20/18 14:17	1
Potassium	375	*	1.00	0.500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Selenium	ND	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Silver	ND		0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 14:17	1
Sodium	60900	*	500	200	mg/L		09/15/18 09:53	09/22/18 21:36	500
Thallium	ND	*	0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 14:17	1
Vanadium	ND	*	0.0200	0.0100	mg/L		09/15/18 09:53	09/20/18 14:17	1
Zinc	0.106	*	0.0500	0.0250	mg/L		09/15/18 09:53	09/20/18 14:17	1

Method: SM 2340B - Total Hardness (as CaCO3) by calculation

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Hardness as calcium carbonate	45000		10.0	5.00	mg/L			09/23/18 11:31	1

General Chemistry

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/17/18 08:56	09/20/18 17:58	1
Bicarbonate Alkalinity as CaCO3	35.8		10.0	5.00	mg/L			09/18/18 16:09	1
Alkalinity	35.8		10.0	5.00	mg/L			09/18/18 16:09	1
Total Dissolved Solids	210000	E	1000	700	mg/L			09/18/18 20:15	1
pH	6.7	HF	0.1	0.1	SU			09/22/18 17:38	1
Total Organic Carbon	18.1		1.00	0.500	mg/L			09/15/18 16:29	1

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	-66.8	U	183	183		169	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Actinium-228	130		32.7	35.1		26.5	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Bismuth-212	-47.2	U	168	168		289	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Bismuth-214	212		32.4	38.8		22.1	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Lead-210	43.8	U	145	145		225	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Lead-212	24.5	U	16.3	16.6		25.1	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Lead-214	212		34.0	40.5		29.8	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Potassium-40	272		195	197		216	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Protactinium-231	10.8	U	563	563		953	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Radium-226	531		245	260	350	293	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Radium-228	130		32.7	35.1		26.5	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Thallium-208	12.7	U	10.0	10.1		17.1	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Thorium-232	130		32.7	35.1		26.5	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Thorium-234	-155	U	112	113		311	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Uranium-235	27.0	U	66.4	66.5		112	pCi/L	09/16/18 22:55	09/18/18 14:29	1
Uranium-238	-155	U	112	113		311	pCi/L	09/16/18 22:55	09/18/18 14:29	1

Other Detected Radionuclides	*Result*	*Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/16/18 22:55*	*09/18/18 14:29*	*1*

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Client Sample ID: Woods County Lower OSage

Lab Sample ID: 490-159194-1

Date Collected: 09/13/18 10:30

Matrix: Water

Date Received: 09/14/18 10:20

Method: 9310 - Gross Alpha / Beta (GFPC)

Analyte	Result	Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	1240	U G	953	963	3.00	1400	pCi/L	09/18/18 09:54	09/20/18 13:40	1
Gross Beta	173	U G	441	441	4.00	739	pCi/L	09/18/18 09:54	09/20/18 13:40	1

Client Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Client Sample ID: Trip Blank

Lab Sample ID: 490-159194-2

Date Collected: 09/13/18 00:01
Date Received: 09/14/18 10:20

Matrix: Water

Method: 8260B - Volatile Organic Compounds (GC/MS)

Analyte	Result	Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/15/18 02:32	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/15/18 02:32	1
Toluene	ND		1.00	0.170	ug/L			09/15/18 02:32	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/15/18 02:32	1

Surrogate	*%Recovery*	*Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*114*		*70 - 130*		*09/15/18 02:32*	*1*
4-Bromofluorobenzene (Surr)	*95*		*70 - 130*		*09/15/18 02:32*	*1*
Dibromofluoromethane (Surr)	*110*		*70 - 130*		*09/15/18 02:32*	*1*
Toluene-d8 (Surr)	*98*		*70 - 130*		*09/15/18 02:32*	*1*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Method: 8260B - Volatile Organic Compounds (GC/MS)

Lab Sample ID: MB 490-542916/6
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/15/18 02:05	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/15/18 02:05	1
Toluene	ND		1.00	0.170	ug/L			09/15/18 02:05	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/15/18 02:05	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*118*		*70 - 130*		*09/15/18 02:05*	*1*
4-Bromofluorobenzene (Surr)	*96*		*70 - 130*		*09/15/18 02:05*	*1*
Dibromofluoromethane (Surr)	*111*		*70 - 130*		*09/15/18 02:05*	*1*
Toluene-d8 (Surr)	*98*		*70 - 130*		*09/15/18 02:05*	*1*

Lab Sample ID: LCS 490-542916/3
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	23.00		ug/L		115	70 - 130
Ethylbenzene	20.0	22.79		ug/L		114	70 - 130
Toluene	20.0	22.64		ug/L		113	70 - 130
Xylenes, Total	40.0	45.73		ug/L		114	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*121*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*101*		*70 - 130*
Toluene-d8 (Surr)	*98*		*70 - 130*

Lab Sample ID: LCSD 490-542916/4
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	24.12		ug/L		121	70 - 130	5	12
Ethylbenzene	20.0	22.98		ug/L		115	70 - 130	1	12
Toluene	20.0	23.44		ug/L		117	70 - 130	3	13
Xylenes, Total	40.0	46.00		ug/L		115	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*120*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*102*		*70 - 130*
Toluene-d8 (Surr)	*100*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-159197-B-1 MSD
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		20.0	25.94		ug/L		130	55 - 147	5	22
Ethylbenzene	ND		20.0	24.95		ug/L		125	65 - 139	10	18
Toluene	ND		20.0	24.87		ug/L		124	64 - 136	7	18
Xylenes, Total	ND		40.0	49.20		ug/L		123	69 - 132	10	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*124*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*103*		*70 - 130*
Toluene-d8 (Surr)	*97*		*70 - 130*

Lab Sample ID: 490-159197-C-1 MS
Matrix: Water
Analysis Batch: 542916

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	ND		20.0	24.69		ug/L		123	55 - 147
Ethylbenzene	ND		20.0	22.53		ug/L		113	65 - 139
Toluene	ND		20.0	23.22		ug/L		116	64 - 136
Xylenes, Total	ND		40.0	44.37		ug/L		111	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*123*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*105*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Lab Sample ID: MB 490-543503/8
Matrix: Water
Analysis Batch: 543503

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/18/18 13:55	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/18/18 13:55	1
Toluene	ND		1.00	0.170	ug/L			09/18/18 13:55	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/18/18 13:55	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*		*09/18/18 13:55*	*1*
4-Bromofluorobenzene (Surr)	*108*		*70 - 130*		*09/18/18 13:55*	*1*
Dibromofluoromethane (Surr)	*101*		*70 - 130*		*09/18/18 13:55*	*1*
Toluene-d8 (Surr)	*100*		*70 - 130*		*09/18/18 13:55*	*1*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: LCS 490-543503/3
Matrix: Water
Analysis Batch: 543503

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	22.21		ug/L		111	70 - 130
Ethylbenzene	20.0	20.29		ug/L		101	70 - 130
Toluene	20.0	20.16		ug/L		101	70 - 130
Xylenes, Total	40.0	39.50		ug/L		99	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*105*		*70 - 130*
4-Bromofluorobenzene (Surr)	*106*		*70 - 130*
Dibromofluoromethane (Surr)	*94*		*70 - 130*
Toluene-d8 (Surr)	*97*		*70 - 130*

Lab Sample ID: LCSD 490-543503/4
Matrix: Water
Analysis Batch: 543503

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	20.0	22.10		ug/L		110	70 - 130	1	12
Ethylbenzene	20.0	19.69		ug/L		98	70 - 130	3	12
Toluene	20.0	19.84		ug/L		99	70 - 130	2	13
Xylenes, Total	40.0	38.99		ug/L		97	70 - 132	1	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*108*		*70 - 130*
4-Bromofluorobenzene (Surr)	*108*		*70 - 130*
Dibromofluoromethane (Surr)	*94*		*70 - 130*
Toluene-d8 (Surr)	*97*		*70 - 130*

Lab Sample ID: 490-159194-1 MS
Matrix: Water
Analysis Batch: 543503

Client Sample ID: Woods County Lower OSage
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	2380		1000	3259		ug/L		88	55 - 147
Ethylbenzene	127		1000	1109		ug/L		98	65 - 139
Toluene	1370		1000	2279		ug/L		91	64 - 136
Xylenes, Total	369		2000	2305		ug/L		97	69 - 132

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*108*		*70 - 130*
4-Bromofluorobenzene (Surr)	*105*		*70 - 130*
Dibromofluoromethane (Surr)	*94*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: 490-159194-1 MSD — **Client Sample ID: Woods County Lower OSage**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543503

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	2380		1000	3331		ug/L		95	55 - 147	2	22
Ethylbenzene	127		1000	1108		ug/L		98	65 - 139	0	18
Toluene	1370		1000	2290		ug/L		92	64 - 136	0	18
Xylenes, Total	369		2000	2314		ug/L		97	69 - 132	0	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*110*		*70 - 130*
4-Bromofluorobenzene (Surr)	*107*		*70 - 130*
Dibromofluoromethane (Surr)	*95*		*70 - 130*
Toluene-d8 (Surr)	*96*		*70 - 130*

Lab Sample ID: MB 490-544177/6 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544177

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Benzene	ND		1.00	0.200	ug/L			09/20/18 14:25	1
Ethylbenzene	ND		1.00	0.190	ug/L			09/20/18 14:25	1
Toluene	ND		1.00	0.170	ug/L			09/20/18 14:25	1
Xylenes, Total	ND		3.00	0.580	ug/L			09/20/18 14:25	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
1,2-Dichloroethane-d4 (Surr)	*116*		*70 - 130*		*09/20/18 14:25*	*1*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*		*09/20/18 14:25*	*1*
Dibromofluoromethane (Surr)	*105*		*70 - 130*		*09/20/18 14:25*	*1*
Toluene-d8 (Surr)	*99*		*70 - 130*		*09/20/18 14:25*	*1*

Lab Sample ID: LCS 490-544177/3 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544177

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Benzene	20.0	23.33		ug/L		117	70 - 130
Ethylbenzene	20.0	23.04		ug/L		115	70 - 130
Toluene	20.0	23.48		ug/L		117	70 - 130
Xylenes, Total	40.0	45.77		ug/L		114	70 - 132

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*108*		*70 - 130*
4-Bromofluorobenzene (Surr)	*98*		*70 - 130*
Dibromofluoromethane (Surr)	*99*		*70 - 130*
Toluene-d8 (Surr)	*100*		*70 - 130*

Method: 8260B - Volatile Organic Compounds (GC/MS) (Continued)

Lab Sample ID: LCSD 490-544177/4
Matrix: Water
Analysis Batch: 544177

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene			20.0	23.12		ug/L		116	70 - 130	1	12
Ethylbenzene			20.0	22.71		ug/L		114	70 - 130	1	12
Toluene			20.0	22.80		ug/L		114	70 - 130	3	13
Xylenes, Total			40.0	44.70		ug/L		112	70 - 132	2	11

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*111*		*70 - 130*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*
Dibromofluoromethane (Surr)	*100*		*70 - 130*
Toluene-d8 (Surr)	*101*		*70 - 130*

Lab Sample ID: 240-101382-B-2 MS
Matrix: Water
Analysis Batch: 544177

Client Sample ID: Matrix Spike
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Benzene	ND		1000	1130		ug/L		113	55 - 147		
Ethylbenzene	ND		1000	1098		ug/L		110	65 - 139		
Toluene	ND		1000	1138		ug/L		114	64 - 136		
Xylenes, Total	ND		2000	2133		ug/L		107	69 - 132		

Surrogate	*MS %Recovery*	*MS Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*109*		*70 - 130*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*
Dibromofluoromethane (Surr)	*98*		*70 - 130*
Toluene-d8 (Surr)	*101*		*70 - 130*

Lab Sample ID: 240-101382-B-2 MSD
Matrix: Water
Analysis Batch: 544177

Client Sample ID: Matrix Spike Duplicate
Prep Type: Total/NA

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Benzene	ND		1000	1133		ug/L		113	55 - 147	0	22
Ethylbenzene	ND		1000	1094		ug/L		109	65 - 139	0	18
Toluene	ND		1000	1146		ug/L		115	64 - 136	1	18
Xylenes, Total	ND		2000	2159		ug/L		108	69 - 132	1	17

Surrogate	*MSD %Recovery*	*MSD Qualifier*	*Limits*
1,2-Dichloroethane-d4 (Surr)	*110*		*70 - 130*
4-Bromofluorobenzene (Surr)	*97*		*70 - 130*
Dibromofluoromethane (Surr)	*97*		*70 - 130*
Toluene-d8 (Surr)	*102*		*70 - 130*

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Method: OK GRO - Oklahoma - Gasoline Range Organic (GC)

Lab Sample ID: MB 490-543592/8
Matrix: Water
Analysis Batch: 543592

Client Sample ID: Method Blank
Prep Type: Total/NA

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C6-C10 OK	ND		20.0	10.0	ug/L			09/18/18 11:20	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
a,a,a-Trifluorotoluene	*104*		*70 - 130*		*09/18/18 11:20*	*1*

Lab Sample ID: LCS 490-543592/7
Matrix: Water
Analysis Batch: 543592

Client Sample ID: Lab Control Sample
Prep Type: Total/NA

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C6-C10 OK	200	215.5		ug/L		108	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*104*		*70 - 130*

Lab Sample ID: LCSD 490-543592/20
Matrix: Water
Analysis Batch: 543592

Client Sample ID: Lab Control Sample Dup
Prep Type: Total/NA

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C6-C10 OK	200	210.4		ug/L		105	80 - 120	2	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
a,a,a-Trifluorotoluene	*103*		*70 - 130*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC)

Lab Sample ID: MB 490-544103/1-A
Matrix: Water
Analysis Batch: 544357

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 544103

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
C10-C28	ND		100	50.0	ug/L		09/20/18 08:29	09/20/18 23:37	1

Surrogate	*MB %Recovery*	*MB Qualifier*	*Limits*	*Prepared*	*Analyzed*	*Dil Fac*
o-Terphenyl	*91*		*50 - 150*	*09/20/18 08:29*	*09/20/18 23:37*	*1*

Lab Sample ID: LCS 490-544103/2-A
Matrix: Water
Analysis Batch: 544357

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 544103

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
C10-C28	500	497.2		ug/L		99	80 - 120

Surrogate	*LCS %Recovery*	*LCS Qualifier*	*Limits*
o-Terphenyl	*109*		*50 - 150*

Method: OK DRO - Oklahoma - Diesel Range Organics (GC) (Continued)

Lab Sample ID: LCSD 490-544103/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544357 — **Prep Batch: 544103**

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
C10-C28			500	500.9		ug/L		100	80 - 120	1	20

Surrogate	*LCSD %Recovery*	*LCSD Qualifier*	*Limits*
o-Terphenyl	*108*		*50 - 150*

Method: 300.0 - Anions, Ion Chromatography

Lab Sample ID: MB 490-542925/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Chloride	ND		1.00	0.700	mg/L			09/14/18 21:52	1
Fluoride	ND		0.100	0.0600	mg/L			09/14/18 21:52	1
Sulfate	ND		1.00	0.600	mg/L			09/14/18 21:52	1

Lab Sample ID: LCS 490-542925/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Chloride			10.0	9.580		mg/L		96	90 - 110		
Fluoride			1.00	0.9829		mg/L		98	90 - 110		
Sulfate			10.0	9.417		mg/L		94	90 - 110		

Lab Sample ID: LCSD 490-542925/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Chloride			10.0	9.591		mg/L		96	90 - 110	0	20
Fluoride			1.00	1.025		mg/L		102	90 - 110	4	20
Sulfate			10.0	9.547		mg/L		95	90 - 110	1	20

Lab Sample ID: 490-159206-E-6 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Bromide	0.594	J *	10.0	8.810		mg/L		82	80 - 120		
Chloride	37.8		10.0	45.89	E	mg/L		80	80 - 120		
Fluoride	0.137		1.00	1.055		mg/L		92	80 - 120		
Sulfate	14.6		10.0	24.32		mg/L		97	80 - 120		

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: 490-159206-E-6 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 542925

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	0.594	J *	10.0	8.839		mg/L		82	80 - 120	0	20
Chloride	37.8		10.0	45.93	E	mg/L		81	80 - 120	0	20
Fluoride	0.137		1.00	1.067		mg/L		93	80 - 120	1	20
Sulfate	14.6		10.0	24.38		mg/L		98	80 - 120	0	20

Lab Sample ID: MB 490-544169/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bromide	ND		1.00	0.0500	mg/L			09/20/18 10:00	1
Chloride	ND		1.00	0.700	mg/L			09/20/18 10:00	1
Fluoride	ND		0.100	0.0600	mg/L			09/20/18 10:00	1
Sulfate	ND		1.00	0.600	mg/L			09/20/18 10:00	1

Lab Sample ID: LCS 490-544169/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	10.0	9.681		mg/L		97	90 - 110
Chloride	10.0	9.822		mg/L		98	90 - 110
Sulfate	10.0	9.597		mg/L		96	90 - 110

Lab Sample ID: LCSD 490-544169/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	10.0	9.694		mg/L		97	90 - 110	0	20
Chloride	10.0	9.854		mg/L		98	90 - 110	0	20
Fluoride	1.00	0.9109		mg/L		91	90 - 110	2	20
Sulfate	10.0	9.764		mg/L		97	90 - 110	2	20

Lab Sample ID: 490-159182-J-11 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Bromide	5.53		10.0	17.19		mg/L		116	80 - 120
Chloride	125	E	10.0	137.5	E 4	mg/L		123	80 - 120
Fluoride	0.228	*	1.00	1.296		mg/L		107	80 - 120
Sulfate	12.5	F1	10.0	25.12	F1	mg/L		125	80 - 120

Method: 300.0 - Anions, Ion Chromatography (Continued)

Lab Sample ID: 490-159182-J-11 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544169

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Bromide	5.53		10.0	16.48		mg/L		109	80 - 120	4	20
Chloride	125	E	10.0	137.9	E 4	mg/L		126	80 - 120	0	20
Fluoride	0.228	*	1.00	1.228		mg/L		100	80 - 120	5	20
Sulfate	12.5	F1	10.0	24.44		mg/L		119	80 - 120	3	20

Lab Sample ID: MB 490-544170/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Nitrate as N	ND		0.100	0.0500	mg/L			09/20/18 10:00	1
Nitrite as N	ND		0.100	0.0500	mg/L			09/20/18 10:00	1

Lab Sample ID: LCS 490-544170/4 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	1.00	0.9557		mg/L		96	90 - 110
Nitrite as N	1.00	0.9140		mg/L		91	90 - 110

Lab Sample ID: LCSD 490-544170/5 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	1.00	0.9534		mg/L		95	90 - 110	0	20
Nitrite as N	1.00	0.9123		mg/L		91	90 - 110	0	20

Lab Sample ID: 490-159182-J-11 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Nitrate as N	0.141	F1	1.00	1.400	F1	mg/L		126	80 - 120
Nitrite as N	ND	F1	1.00	0.7019	F1	mg/L		70	80 - 120

Lab Sample ID: 490-159182-J-11 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544170

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Nitrate as N	0.141	F1	1.00	1.340		mg/L		120	80 - 120	4	20
Nitrite as N	ND	F1	1.00	0.6638	F1	mg/L		66	80 - 120	6	20

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Method: 200.7 Rev 4.4 - Metals (ICP)

Lab Sample ID: MB 490-542965/1-A
Matrix: Water
Analysis Batch: 544281

Client Sample ID: Method Blank
Prep Type: Total/NA
Prep Batch: 542965

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Aluminum	ND		0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Antimony	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Arsenic	ND		0.0100	0.00860	mg/L		09/15/18 09:53	09/20/18 13:33	1
Barium	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Beryllium	ND		0.00400	0.00200	mg/L		09/15/18 09:53	09/20/18 13:33	1
Cadmium	ND		0.00100	0.000500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Calcium	ND		1.00	0.500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Chromium	ND		0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 13:33	1
Cobalt	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Copper	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Iron	ND		0.100	0.0500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Lead	ND		0.00500	0.00200	mg/L		09/15/18 09:53	09/20/18 13:33	1
Magnesium	ND		1.00	0.250	mg/L		09/15/18 09:53	09/20/18 13:33	1
Manganese	ND		0.0150	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Nickel	ND		0.0100	0.00300	mg/L		09/15/18 09:53	09/20/18 13:33	1
Potassium	ND		1.00	0.500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Selenium	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Silver	ND		0.00500	0.00300	mg/L		09/15/18 09:53	09/20/18 13:33	1
Sodium	ND		1.00	0.400	mg/L		09/15/18 09:53	09/20/18 13:33	1
Thallium	ND		0.0100	0.00500	mg/L		09/15/18 09:53	09/20/18 13:33	1
Vanadium	ND		0.0200	0.0100	mg/L		09/15/18 09:53	09/20/18 13:33	1
Zinc	ND		0.0500	0.0250	mg/L		09/15/18 09:53	09/20/18 13:33	1

Lab Sample ID: LCS 490-542965/2-A
Matrix: Water
Analysis Batch: 544281

Client Sample ID: Lab Control Sample
Prep Type: Total/NA
Prep Batch: 542965

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Aluminum	1.00	1.017		mg/L		102	85 - 115
Antimony	0.100	0.1049		mg/L		105	85 - 115
Arsenic	0.100	0.09990		mg/L		100	85 - 115
Barium	0.100	0.1032		mg/L		103	85 - 115
Beryllium	0.100	0.09920		mg/L		99	85 - 115
Cadmium	0.100	0.1089		mg/L		109	85 - 115
Calcium	10.0	9.676		mg/L		97	85 - 115
Chromium	0.100	0.1024		mg/L		102	85 - 115
Cobalt	0.100	0.1039		mg/L		104	85 - 115
Copper	0.100	0.09970		mg/L		100	85 - 115
Iron	1.00	0.9801		mg/L		98	85 - 115
Lead	0.100	0.09940		mg/L		99	85 - 115
Magnesium	10.0	10.12		mg/L		101	85 - 115
Manganese	0.100	0.09760		mg/L		98	85 - 115
Nickel	0.100	0.1021		mg/L		102	85 - 115
Potassium	10.0	9.842		mg/L		98	85 - 115
Selenium	0.100	0.1131		mg/L		113	85 - 115
Silver	0.100	0.08940		mg/L		89	85 - 115
Sodium	10.0	9.488		mg/L		95	85 - 115
Thallium	0.100	0.1037		mg/L		104	85 - 115

Method: 200.7 Rev 4.4 - Metals (ICP) (Continued)

Lab Sample ID: LCS 490-542965/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544281 — **Prep Batch: 542965**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Vanadium	0.100	0.1051		mg/L		105	85 - 115
Zinc	0.100	0.1150		mg/L		115	85 - 115

Lab Sample ID: LCSD 490-542965/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544281 — **Prep Batch: 542965**

Analyte	Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Aluminum	2.00	2.093	*	mg/L		105	85 - 115	69	20
Antimony	0.100	0.1093		mg/L		109	85 - 115	4	20
Arsenic	0.200	0.2108	*	mg/L		105	85 - 115	71	20
Barium	0.200	0.2138	*	mg/L		107	85 - 115	70	20
Beryllium	0.200	0.2056	*	mg/L		103	85 - 115	70	20
Cadmium	0.200	0.2243	*	mg/L		112	85 - 115	69	20
Calcium	20.0	20.75	*	mg/L		104	85 - 115	73	20
Chromium	0.200	0.2114	*	mg/L		106	85 - 115	69	20
Cobalt	0.200	0.2127	*	mg/L		106	85 - 115	69	20
Copper	0.200	0.2057	*	mg/L		103	85 - 115	69	20
Iron	2.00	2.022	*	mg/L		101	85 - 115	69	20
Lead	0.200	0.2042	*	mg/L		102	85 - 115	69	20
Magnesium	20.0	20.79	*	mg/L		104	85 - 115	69	20
Manganese	0.200	0.1996	*	mg/L		100	85 - 115	69	20
Nickel	0.200	0.2093	*	mg/L		105	85 - 115	69	20
Potassium	20.0	20.42	*	mg/L		102	85 - 115	70	20
Selenium	0.200	0.2300	*	mg/L		115	85 - 115	68	20
Silver	0.100	0.09060		mg/L		91	85 - 115	1	20
Sodium	20.0	19.56	*	mg/L		98	85 - 115	69	20
Thallium	0.200	0.2120	*	mg/L		106	85 - 115	69	20
Vanadium	0.200	0.2138	*	mg/L		107	85 - 115	68	20
Zinc	0.200	0.2355	*	mg/L		118	85 - 115	69	20

Method: 365.4 - Phosphorus, Total

Lab Sample ID: MB 490-543181/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Phosphorus, Total	ND		0.100	0.0500	mg/L		09/17/18 08:56	09/20/18 17:54	1

Lab Sample ID: LCS 490-543181/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Phosphorus, Total	2.00	1.880		mg/L		94	90 - 110

Method: 365.4 - Phosphorus, Total (Continued)

Lab Sample ID: LCSD 490-543181/3-A — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total			2.00	1.840		mg/L		92	90 - 110	2	20

Lab Sample ID: 490-159219-A-1-B MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits		
Phosphorus, Total	2.93		2.00	4.990		mg/L		103	73 - 119		

Lab Sample ID: 490-159219-A-1-C MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544073 — **Prep Batch: 543181**

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Phosphorus, Total	2.93		2.00	4.830		mg/L		95	73 - 119	3	20

Method: SM 2320B - Alkalinity

Lab Sample ID: MB 490-543924/29 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Bicarbonate Alkalinity as CaCO3	ND		10.0	5.00	mg/L			09/18/18 15:07	1
Alkalinity	ND		10.0	5.00	mg/L			09/18/18 15:07	1

Lab Sample ID: LCS 490-543924/30 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte			Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits		
Alkalinity			100	95.76		mg/L		96	90 - 110		

Lab Sample ID: LCSD 490-543924/52 — **Client Sample ID: Lab Control Sample Dup**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte			Spike Added	LCSD Result	LCSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Alkalinity			100	98.27		mg/L		98	90 - 110	3	20

Lab Sample ID: 490-159198-J-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543924

Analyte	Sample Result	Sample Qualifier		DU Result	DU Qualifier	Unit	D			RPD	RPD Limit
Bicarbonate Alkalinity as CaCO3	167			167.0		mg/L				0.2	20
Alkalinity	167			167.0		mg/L				0.2	20

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Method: SM 2540C - Solids, Total Dissolved (TDS)

Lab Sample ID: MB 490-543706/1 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Dissolved Solids	ND		10.0	7.00	mg/L			09/18/18 20:15	1

Lab Sample ID: LCS 490-543706/2 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Dissolved Solids	100	104.0		mg/L		104	90 - 110

Lab Sample ID: 490-159200-H-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Total Dissolved Solids	592		576.0		mg/L		3	20

Lab Sample ID: 590-9365-E-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543706

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
Total Dissolved Solids	90.0		110.0		mg/L		20	20

Method: SM 4500 H+ B - pH

Lab Sample ID: 490-159113-E-1 DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 544827

Analyte	Sample Result	Sample Qualifier	DU Result	DU Qualifier	Unit	D	RPD	RPD Limit
pH	8.4		8.4		SU		0	20

Method: SM 5310B - Organic Carbon, Total (TOC)

Lab Sample ID: MB 490-543099/3 — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	MB Result	MB Qualifier	RL	MDL	Unit	D	Prepared	Analyzed	Dil Fac
Total Organic Carbon	ND		1.00	0.500	mg/L			09/15/18 13:49	1

Lab Sample ID: LCS 490-543099/6 — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	Spike Added	LCS Result	LCS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	10.0	9.913		mg/L		99	90 - 110

Method: SM 5310B - Organic Carbon, Total (TOC) (Continued)

Lab Sample ID: 490-159137-A-1 MS — **Client Sample ID: Matrix Spike**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	Sample Result	Sample Qualifier	Spike Added	MS Result	MS Qualifier	Unit	D	%Rec	%Rec. Limits
Total Organic Carbon	14.0		40.0	60.39		mg/L		116	74 - 134

Lab Sample ID: 490-159137-A-1 MSD — **Client Sample ID: Matrix Spike Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 543099

Analyte	Sample Result	Sample Qualifier	Spike Added	MSD Result	MSD Qualifier	Unit	D	%Rec	%Rec. Limits	RPD	RPD Limit
Total Organic Carbon	14.0		40.0	60.30		mg/L		116	74 - 134	0	20

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS)

Lab Sample ID: MB 160-389656/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 389815 — **Prep Batch: 389656**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Actinium-227	-16.45	U	32.6	32.6		121	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Actinium-228	9.426	U	18.5	18.5		41.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Bismuth-212	-48.91	U	129	129		221	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Bismuth-214	-28.43	U	17.7	17.9		67.7	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Lead-210	35.85	U	132	132		200	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Lead-212	-3.925	U	15.5	15.5		26.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Lead-214	-5.502	U	16.5	16.5		29.2	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Potassium-40	-71.97	U	136	136		195	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Protactinium-231	87.82	U	224	225		516	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Radium-226	268.5		152	158	350	171	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Radium-228	9.426	U	18.5	18.5		41.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Thallium-208	1.069	U	4.00	4.00		10.6	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Thorium-232	9.426	U	18.5	18.5		41.8	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Thorium-234	26.12	U	80.8	80.9		140	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Uranium-235	14.40	U	48.9	48.9		82.1	pCi/L	09/16/18 22:55	09/17/18 10:04	1
Uranium-238	26.12	U	80.8	80.9		140	pCi/L	09/16/18 22:55	09/17/18 10:04	1

Other Detected Radionuclides	*MB Result*	*MB Qualifier*	*Count Uncert. (2σ+/-)*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*	*Prepared*	*Analyzed*	*Dil Fac*
Other Detected Radionuclide	*None*						*pCi/L*	*09/16/18 22:55*	*09/17/18 10:04*	*1*

Lab Sample ID: LCS 160-389656/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 389814 — **Prep Batch: 389656**

Analyte	Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits
Americium-241	136000	133400		15400		502	pCi/L	98	90 - 111
Cesium-137	45300	43680		4390		152	pCi/L	96	90 - 111
Cobalt-60	32300	31230		3100		105	pCi/L	97	89 - 110

Method: 901.1 - Radium-226 & Other Gamma Emitters (GS) (Continued)

Lab Sample ID: 160-30723-F-1-B DU — **Client Sample ID: Duplicate**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 389815 — **Prep Batch: 389656**

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Actinium-227	-239	U		41.47	U	71.5		438	pCi/L			0.55	1
Actinium-228	1750			1743		198		111	pCi/L			0.02	1
Bismuth-212	-342	U		571.3	F	300		308	pCi/L			1.14	1
Bismuth-214	3600			4219		444		64.4	pCi/L			0.75	1
Lead-210	-523	U		-39.59	U	441		626	pCi/L			0.67	1
Lead-212	338			334.3		59.7		56.4	pCi/L			0.03	1
Lead-214	4140			4417		471		75.8	pCi/L			0.30	1
Potassium-40	-123	U		323.7	U	316		334	pCi/L			0.63	1
Protactinium-231	-546	U		-402.5	U	1850		3060	pCi/L			0.03	1
Radium-226	14800	G		13280	G	2360	350	922	pCi/L			0.30	1
Radium-228	1750			1743		198		111	pCi/L			0.02	1
Thallium-208	107			106.2		31.9		31.5	pCi/L			0.01	1
Thorium-232	1750			1743		198		111	pCi/L			0.02	1
Thorium-234	133	U		-35.89	U	961		1590	pCi/L			0.11	1
Uranium-235	-7.70	U		66.76	U	222		377	pCi/L			0.08	1
Uranium-238	133	U		-35.89	U	961		1590	pCi/L			0.11	1

Other Detected Radionuclides	*Sample Result*	*Sample Qual*		*DU Result*	*DU Qual*	*Total Uncert. (2σ+/-)*	*RL*	*MDC*	*Unit*			*RER*	*RER Limit*
Other Detected Radionuclide	*None*			*None*					*pCi/L*				

Method: 9310 - Gross Alpha / Beta (GFPC)

Lab Sample ID: MB 160-389969/1-A — **Client Sample ID: Method Blank**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte	MB Result	MB Qualifier	Count Uncert. (2σ+/-)	Total Uncert. (2σ+/-)	RL	MDC	Unit	Prepared	Analyzed	Dil Fac
Gross Alpha	0.2193	U	0.564	0.564	3.00	1.01	pCi/L	09/18/18 09:54	09/20/18 13:39	1
Gross Beta	0.05579	U	0.557	0.557	4.00	0.977	pCi/L	09/18/18 09:54	09/20/18 13:39	1

Lab Sample ID: LCS 160-389969/2-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte			Spike Added	LCS Result	LCS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha			51.0	47.10		6.75	3.00	1.29	pCi/L	92	73 - 133		

Lab Sample ID: LCSB 160-389969/3-A — **Client Sample ID: Lab Control Sample**
Matrix: Water — **Prep Type: Total/NA**
Analysis Batch: 390511 — **Prep Batch: 389969**

Analyte			Spike Added	LCSB Result	LCSB Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta			87.7	86.33		9.16	4.00	0.979	pCi/L	98	75 - 125		

QC Sample Results

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Lab Sample ID: 160-30328-A-15-C MS
Matrix: Water
Analysis Batch: 390511

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 389969

Analyte	Sample Result	Sample Qual	Spike Added	MS Result	MS Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Alpha	3.25	G	112	116.9		16.8	3.00	3.67	pCi/L	101	60 - 140		

Lab Sample ID: 160-30328-A-15-D MSBT
Matrix: Water
Analysis Batch: 390511

Client Sample ID: Matrix Spike
Prep Type: Total/NA
Prep Batch: 389969

Analyte	Sample Result	Sample Qual	Spike Added	MSBT Result	MSBT Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit	%Rec	%Rec. Limits		
Gross Beta	7.57		193	199.9		21.2	4.00	2.41	pCi/L	100	60 - 140		

Lab Sample ID: 160-30328-A-15-E DU
Matrix: Water
Analysis Batch: 390511

Client Sample ID: Duplicate
Prep Type: Total/NA
Prep Batch: 389969

Analyte	Sample Result	Sample Qual		DU Result	DU Qual	Total Uncert. (2σ+/-)	RL	MDC	Unit			RER	RER Limit
Gross Alpha	3.25	G		6.881	G	3.65	3.00	4.90	pCi/L			0.61	1
Gross Beta	7.57			10.17		2.33	4.00	2.39	pCi/L			0.58	1

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

GC/MS VOA

Analysis Batch: 542916

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-2	Trip Blank	Total/NA	Water	8260B	
MB 490-542916/6	Method Blank	Total/NA	Water	8260B	
LCS 490-542916/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-542916/4	Lab Control Sample Dup	Total/NA	Water	8260B	
490-159197-B-1 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	
490-159197-C-1 MS	Matrix Spike	Total/NA	Water	8260B	

Analysis Batch: 543503

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	8260B	
MB 490-543503/8	Method Blank	Total/NA	Water	8260B	
LCS 490-543503/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-543503/4	Lab Control Sample Dup	Total/NA	Water	8260B	
490-159194-1 MS	Woods County Lower OSage	Total/NA	Water	8260B	
490-159194-1 MSD	Woods County Lower OSage	Total/NA	Water	8260B	

Analysis Batch: 544177

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	8260B	
MB 490-544177/6	Method Blank	Total/NA	Water	8260B	
LCS 490-544177/3	Lab Control Sample	Total/NA	Water	8260B	
LCSD 490-544177/4	Lab Control Sample Dup	Total/NA	Water	8260B	
240-101382-B-2 MS	Matrix Spike	Total/NA	Water	8260B	
240-101382-B-2 MSD	Matrix Spike Duplicate	Total/NA	Water	8260B	

GC VOA

Analysis Batch: 543592

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	OK GRO	
MB 490-543592/8	Method Blank	Total/NA	Water	OK GRO	
LCS 490-543592/7	Lab Control Sample	Total/NA	Water	OK GRO	
LCSD 490-543592/20	Lab Control Sample Dup	Total/NA	Water	OK GRO	

GC Semi VOA

Prep Batch: 544103

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	3510C	
MB 490-544103/1-A	Method Blank	Total/NA	Water	3510C	
LCS 490-544103/2-A	Lab Control Sample	Total/NA	Water	3510C	
LCSD 490-544103/3-A	Lab Control Sample Dup	Total/NA	Water	3510C	

Analysis Batch: 544357

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
MB 490-544103/1-A	Method Blank	Total/NA	Water	OK DRO	544103
LCS 490-544103/2-A	Lab Control Sample	Total/NA	Water	OK DRO	544103
LCSD 490-544103/3-A	Lab Control Sample Dup	Total/NA	Water	OK DRO	544103

GC Semi VOA (Continued)

Analysis Batch: 544512

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	OK DRO	544103

HPLC/IC

Analysis Batch: 542925

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	300.0	
MB 490-542925/3	Method Blank	Total/NA	Water	300.0	
LCS 490-542925/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-542925/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-159206-E-6 MS	Matrix Spike	Total/NA	Water	300.0	
490-159206-E-6 MSD	Matrix Spike Duplicate	Total/NA	Water	300.0	

Analysis Batch: 544169

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	300.0	
490-159194-1	Woods County Lower OSage	Total/NA	Water	300.0	
MB 490-544169/3	Method Blank	Total/NA	Water	300.0	
LCS 490-544169/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-544169/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-159182-J-11 MS	Matrix Spike	Total/NA	Water	300.0	
490-159182-J-11 MSD	Matrix Spike Duplicate	Total/NA	Water	300.0	

Analysis Batch: 544170

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	300.0	
MB 490-544170/3	Method Blank	Total/NA	Water	300.0	
LCS 490-544170/4	Lab Control Sample	Total/NA	Water	300.0	
LCSD 490-544170/5	Lab Control Sample Dup	Total/NA	Water	300.0	
490-159182-J-11 MS	Matrix Spike	Total/NA	Water	300.0	
490-159182-J-11 MSD	Matrix Spike Duplicate	Total/NA	Water	300.0	

Metals

Prep Batch: 542965

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	200.7	
MB 490-542965/1-A	Method Blank	Total/NA	Water	200.7	
LCS 490-542965/2-A	Lab Control Sample	Total/NA	Water	200.7	
LCSD 490-542965/3-A	Lab Control Sample Dup	Total/NA	Water	200.7	

Analysis Batch: 544281

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	200.7 Rev 4.4	542965
490-159194-1	Woods County Lower OSage	Total/NA	Water	200.7 Rev 4.4	542965
490-159194-1	Woods County Lower OSage	Total/NA	Water	200.7 Rev 4.4	542965
MB 490-542965/1-A	Method Blank	Total/NA	Water	200.7 Rev 4.4	542965
LCS 490-542965/2-A	Lab Control Sample	Total/NA	Water	200.7 Rev 4.4	542965
LCSD 490-542965/3-A	Lab Control Sample Dup	Total/NA	Water	200.7 Rev 4.4	542965

Metals (Continued)

Analysis Batch: 544886

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	SM 2340B	

Analysis Batch: 544892

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	200.7 Rev 4.4	542965

General Chemistry

Analysis Batch: 543099

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	SM 5310B	
MB 490-543099/3	Method Blank	Total/NA	Water	SM 5310B	
LCS 490-543099/6	Lab Control Sample	Total/NA	Water	SM 5310B	
490-159137-A-1 MS	Matrix Spike	Total/NA	Water	SM 5310B	
490-159137-A-1 MSD	Matrix Spike Duplicate	Total/NA	Water	SM 5310B	

Prep Batch: 543181

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	365.2/365.3/365	
MB 490-543181/1-A	Method Blank	Total/NA	Water	365.2/365.3/365	
LCS 490-543181/2-A	Lab Control Sample	Total/NA	Water	365.2/365.3/365	
LCSD 490-543181/3-A	Lab Control Sample Dup	Total/NA	Water	365.2/365.3/365	
490-159219-A-1-B MS	Matrix Spike	Total/NA	Water	365.2/365.3/365	
490-159219-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	365.2/365.3/365	

Analysis Batch: 543706

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	SM 2540C	
MB 490-543706/1	Method Blank	Total/NA	Water	SM 2540C	
LCS 490-543706/2	Lab Control Sample	Total/NA	Water	SM 2540C	
490-159200-H-1 DU	Duplicate	Total/NA	Water	SM 2540C	
590-9365-E-1 DU	Duplicate	Total/NA	Water	SM 2540C	

Analysis Batch: 543924

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	SM 2320B	
MB 490-543924/29	Method Blank	Total/NA	Water	SM 2320B	
LCS 490-543924/30	Lab Control Sample	Total/NA	Water	SM 2320B	
LCSD 490-543924/52	Lab Control Sample Dup	Total/NA	Water	SM 2320B	
490-159198-J-1 DU	Duplicate	Total/NA	Water	SM 2320B	

Analysis Batch: 544073

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	365.4	543181
MB 490-543181/1-A	Method Blank	Total/NA	Water	365.4	543181
LCS 490-543181/2-A	Lab Control Sample	Total/NA	Water	365.4	543181
LCSD 490-543181/3-A	Lab Control Sample Dup	Total/NA	Water	365.4	543181
490-159219-A-1-B MS	Matrix Spike	Total/NA	Water	365.4	543181
490-159219-A-1-C MSD	Matrix Spike Duplicate	Total/NA	Water	365.4	543181

QC Association Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

General Chemistry (Continued)

Analysis Batch: 544827

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	SM 4500 H+ B	
LCS 490-544827/1	Lab Control Sample	Total/NA	Water	SM 4500 H+ B	
490-159113-E-1 DU	Duplicate	Total/NA	Water	SM 4500 H+ B	

Rad

Prep Batch: 389656

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	Fill_Geo-0	
MB 160-389656/1-A	Method Blank	Total/NA	Water	Fill_Geo-0	
LCS 160-389656/2-A	Lab Control Sample	Total/NA	Water	Fill_Geo-0	
160-30723-F-1-B DU	Duplicate	Total/NA	Water	Fill_Geo-0	

Prep Batch: 389969

Lab Sample ID	Client Sample ID	Prep Type	Matrix	Method	Prep Batch
490-159194-1	Woods County Lower OSage	Total/NA	Water	Evaporation	
MB 160-389969/1-A	Method Blank	Total/NA	Water	Evaporation	
LCS 160-389969/2-A	Lab Control Sample	Total/NA	Water	Evaporation	
LCSB 160-389969/3-A	Lab Control Sample	Total/NA	Water	Evaporation	
160-30328-A-15-C MS	Matrix Spike	Total/NA	Water	Evaporation	
160-30328-A-15-D MSBT	Matrix Spike	Total/NA	Water	Evaporation	
160-30328-A-15-E DU	Duplicate	Total/NA	Water	Evaporation	

Lab Chronicle

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Client Sample ID: Woods County Lower OSage

Lab Sample ID: 490-159194-1
Date Collected: 09/13/18 10:30
Matrix: Water
Date Received: 09/14/18 10:20

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		10	10 mL	10 mL	544177	09/20/18 16:43	BBR	TAL NSH
Total/NA	Analysis	8260B		50	10 mL	10 mL	543503	09/18/18 21:37	RP	TAL NSH
Total/NA	Analysis	OK GRO		10	5 mL	5 mL	543592	09/18/18 15:16	GWM	TAL NSH
Total/NA	Prep	3510C			1173.8 mL	1 mL	544103	09/20/18 08:30	TJB	TAL NSH
Total/NA	Analysis	OK DRO		5			544512	09/21/18 14:58	JDJ	TAL NSH
Total/NA	Analysis	300.0		20			542925	09/15/18 01:33	SW1	TAL NSH
Total/NA	Analysis	300.0		200			544169	09/20/18 12:31	SW1	TAL NSH
Total/NA	Analysis	300.0		200			544170	09/20/18 12:31	SW1	TAL NSH
Total/NA	Analysis	300.0		5000			544169	09/20/18 12:42	SW1	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	542965	09/15/18 09:53	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		1			544281	09/20/18 14:17	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	542965	09/15/18 09:53	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		10			544281	09/20/18 14:23	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	542965	09/15/18 09:53	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		100			544281	09/20/18 14:36	LDC	TAL NSH
Total/NA	Prep	200.7			50 mL	50 mL	542965	09/15/18 09:53	WJE	TAL NSH
Total/NA	Analysis	200.7 Rev 4.4		500			544892	09/22/18 21:36	LDC	TAL NSH
Total/NA	Analysis	SM 2340B		1			544886	09/23/18 11:31	LEG	TAL NSH
Total/NA	Prep	365.2/365.3/365			20 mL	20 mL	543181	09/17/18 08:56	LDT	TAL NSH
Total/NA	Analysis	365.4		1	20 mL	20 mL	544073	09/20/18 17:58	SDL	TAL NSH
Total/NA	Analysis	SM 2320B		1	35 mL	35 mL	543924	09/18/18 16:09	BMC	TAL NSH
Total/NA	Analysis	SM 2540C		1	1 mL	100 mL	543706	09/18/18 20:15	AEC	TAL NSH
Total/NA	Analysis	SM 4500 H+ B		1			544827	09/22/18 17:38	MXX	TAL NSH
Total/NA	Analysis	SM 5310B		1	50 mL	50 mL	543099	09/15/18 16:29	CLJ	TAL NSH
Total/NA	Prep	Fill_Geo-0			1000 mL	1.0 mL	389656	09/16/18 22:55	SJS	TAL SL
Total/NA	Analysis	901.1		1			389996	09/18/18 14:29	CDR	TAL SL
Total/NA	Prep	Evaporation			0.25 mL	1.0 g	389969	09/18/18 09:54	MRB	TAL SL
Total/NA	Analysis	9310		1			390511	09/20/18 13:40	RTM	TAL SL

Client Sample ID: Trip Blank

Lab Sample ID: 490-159194-2
Date Collected: 09/13/18 00:01
Matrix: Water
Date Received: 09/14/18 10:20

Prep Type	Batch Type	Batch Method	Run	Dil Factor	Initial Amount	Final Amount	Batch Number	Prepared or Analyzed	Analyst	Lab
Total/NA	Analysis	8260B		1	10 mL	10 mL	542916	09/15/18 02:32	AK1	TAL NSH

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Method Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Method	Method Description	Protocol	Laboratory
8260B	Volatile Organic Compounds (GC/MS)	SW846	TAL NSH
OK GRO	Oklahoma - Gasoline Range Organic (GC)	OK-DEQ	TAL NSH
OK DRO	Oklahoma - Diesel Range Organics (GC)	OK-DEQ	TAL NSH
300.0	Anions, Ion Chromatography	MCAWW	TAL NSH
200.7 Rev 4.4	Metals (ICP)	EPA	TAL NSH
SM 2340B	Total Hardness (as CaCO3) by calculation	SM	TAL NSH
365.4	Phosphorus, Total	EPA	TAL NSH
SM 2320B	Alkalinity	SM	TAL NSH
SM 2540C	Solids, Total Dissolved (TDS)	SM	TAL NSH
SM 4500 H+ B	pH	SM	TAL NSH
SM 5310B	Organic Carbon, Total (TOC)	SM	TAL NSH
200.7	Preparation, Total Metals	EPA	TAL NSH
3510C	Liquid-Liquid Extraction (Separatory Funnel)	SW846	TAL NSH
365.2/365.3/365	Phosphorus, Total	MCAWW	TAL NSH
5030B	Purge and Trap	SW846	TAL NSH

Protocol References:

EPA = US Environmental Protection Agency
MCAWW = "Methods For Chemical Analysis Of Water And Wastes", EPA-600/4-79-020, March 1983 And Subsequent Revisions.
OK-DEQ = "Oklahoma Department of Environmental Quality"
SM = "Standard Methods For The Examination Of Water And Wastewater"
SW846 = "Test Methods For Evaluating Solid Waste, Physical/Chemical Methods", Third Edition, November 1986 And Its Updates.

Laboratory References:

TAL NSH = TestAmerica Nashville, 2960 Foster Creighton Drive, Nashville, TN 37204, TEL (615)726-0177

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Laboratory: TestAmerica Nashville

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
A2LA	ISO/IEC 17025		0453.07	12-31-19
Alaska (UST)	State Program	10	UST-087	06-30-19
Arizona	State Program	9	AZ0473	05-05-19
Arkansas DEQ	State Program	6	88-0737	04-25-19
California	State Program	9	2938	10-31-18
Connecticut	State Program	1	PH-0220	12-31-19
Florida	NELAP	4	E87358	06-30-19
Georgia	State Program	4	NA: NELAP & A2LA	12-31-19
Illinois	NELAP	5	200010	12-09-18
Iowa	State Program	7	131	04-01-20
Kansas	NELAP	7	E-10229	10-31-18
Kentucky (UST)	State Program	4	19	06-30-19
Kentucky (WW)	State Program	4	90038	12-31-18
Louisiana	NELAP	6	30613	06-30-19
Maine	State Program	1	TN00032	11-03-19
Maryland	State Program	3	316	03-31-19
Massachusetts	State Program	1	M-TN032	06-30-19
Minnesota	NELAP	5	047-999-345	12-31-18
Mississippi	State Program	4	N/A	06-30-19
Montana (UST)	State Program	8	NA	02-24-20
Nevada	State Program	9	TN00032	07-31-19
New Hampshire	NELAP	1	2963	10-09-18
New Jersey	NELAP	2	TN965	06-30-19
New York	NELAP	2	11342	03-31-19
North Carolina (WW/SW)	State Program	4	387	12-31-18
North Dakota	State Program	8	R-146	06-30-19
Ohio VAP	State Program	5	CL0033	07-06-19
Oklahoma	State Program	6	9412	08-31-19
Oregon	NELAP	10	TN200001	04-26-19
Pennsylvania	NELAP	3	68-00585	07-31-19
Rhode Island	State Program	1	LAO00268	12-30-18
South Carolina	State Program	4	84009 (001)	02-28-19
Tennessee	State Program	4	2008	02-23-20
Texas	NELAP	6	T104704077	08-31-19
USDA	Federal		P330-13-00306	12-01-19
Utah	NELAP	8	TN00032	07-31-19
Virginia	NELAP	3	460152	06-14-19
Washington	State Program	10	C789	07-19-19
West Virginia DEP	State Program	3	219	02-28-19
Wisconsin	State Program	5	998020430	08-31-19
Wyoming (UST)	A2LA	8	453.07	12-31-19

Laboratory: TestAmerica St. Louis

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Alaska	State Program	10	MO00054	06-30-19
ANAB	DoD ELAP		L2305	04-06-19
Arizona	State Program	9	AZ0813	12-08-18
California	State Program	9	2886	06-30-19

Accreditation/Certification Summary

Client: CH2M Hill, Inc.
Project/Site: OWRB Study Phase II

TestAmerica Job ID: 490-159194-1
SDG: Woods County Lower OSage

Laboratory: TestAmerica St. Louis (Continued)

All accreditations/certifications held by this laboratory are listed. Not all accreditations/certifications are applicable to this report.

Authority	Program	EPA Region	Identification Number	Expiration Date
Connecticut	State Program	1	PH-0241	03-31-19
Florida	NELAP	4	E87689	06-30-19
Illinois	NELAP	5	200023	11-30-18
Iowa	State Program	7	373	12-01-18
Kansas	NELAP	7	E-10236	10-31-18
Kentucky (DW)	State Program	4	90125	12-31-18
Louisiana	NELAP	6	04080	06-30-19
Louisiana (DW)	NELAP	6	LA180017	12-31-18
Maryland	State Program	3	310	09-30-19
Michigan	State Program	5	9005	06-30-18 *
Missouri	State Program	7	780	06-30-19
Nevada	State Program	9	MO000542018-1	07-31-19
New Jersey	NELAP	2	MO002	06-30-19
New York	NELAP	2	11616	03-31-19
North Dakota	State Program	8	R207	06-30-19
NRC	NRC		24-24817-01	12-31-22
Oklahoma	State Program	6	9997	08-31-19
Pennsylvania	NELAP	3	68-00540	02-28-19
South Carolina	State Program	4	85002001	06-30-19
Texas	NELAP	6	T104704193-18-12	07-31-19
US Fish & Wildlife	Federal		058448	07-31-19
USDA	Federal		P330-17-0028	02-02-20
Utah	NELAP	8	MO000542016-8	07-31-18 *
Virginia	NELAP	3	460230	06-14-19
Washington	State Program	10	C592	08-30-19
West Virginia DEP	State Program	3	381	10-31-18 *

* Accreditation/Certification renewal pending - accreditation/certification considered valid.

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING
Nashville, TN

COOLER RECEIPT FORM

490-159194 Chain of Custody

Cooler Received/Opened On 9/14/2018 @ 1020

Time Samples Removed From Cooler 12:55 Time Samples Placed In Storage 13:04 (2 Hour Window)

1. Tracking # 8169 (last 4 digits, FedEx) Courier: FedEx

   IR Gun ID 17960357 pH Strip Lot HC849161 Chlorine Strip Lot 040578K 14740456

2. Temperature of rep. sample or temp blank when opened: 12.4 Degrees Celsius 14.5

3. If Item #2 temperature is 0°C or less, was the representative sample or temp blank frozen? YES NO...NA

4. Were custody seals on outside of cooler? YES...NO...NA

   If yes, how many and where: 1 front

5. Were the seals intact, signed, and dated correctly? YES...NO...NA

6. Were custody papers inside cooler? YES...NO...NA

I certify that I opened the cooler and answered questions 1-6 (intial) GH

7. Were custody seals on containers: YES NO and Intact YES...NO...NA

   Were these signed and dated correctly? YES...NO...NA

8. Packing mat'l used? Bubblewrap Plastic bag Peanuts Vermiculite Foam Insert Paper Other None

9. Cooling process: Ice Ice-pack Ice (direct contact) Dry ice Other None Water only

10. Did all containers arrive in good condition (unbroken)? YES...NO...NA

11. Were all container labels complete (#, date, signed, pres., etc)? YES...NO...NA

12. Did all container labels and tags agree with custody papers? YES...NO...NA

13a. Were VOA vials received? YES...NO...NA

   b. Was there any observable headspace present in any VOA vial? YES...NO...NA

Larger than this.

14. Was there a Trip Blank in this cooler? YES...NO...NA If multiple coolers, sequence #_____

I certify that I unloaded the cooler and answered questions 7-14 (intial) KD

15a. On pres'd bottles, did pH test strips suggest preservation reached the correct pH level? YES...NO...NA

   b. Did the bottle labels indicate that the correct preservatives were used YES...NO...NA

16. Was residual chlorine present? YES...NO...NA

I certify that I checked for chlorine and pH as per SOP and answered questions 15-16 (intial) KD

17. Were custody papers properly filled out (ink, signed, etc)? YES...NO...NA

18. Did you sign the custody papers in the appropriate place? YES...NO...NA

19. Were correct containers used for the analysis requested? YES...NO...NA

20. Was sufficient amount of sample sent in each container? YES...NO...NA

I certify that I entered this project into LIMS and answered questions 17-20 (intial) KD

I certify that I attached a label with the unique LIMS number to each container (intial) KD

21. Were there Non-Conformance issues at login? YES...NO Was a NCM generated? YES...NO...#_____

BIS = Broken in shipment
Cooler Receipt Form.doc

LF-1
End of Form

Revised 8/23/17

TestAmerica Nashville
2960 Foster Creighton Drive
Nashville, TN 37204
Phone (615) 726-0177 Fax (615) 726-3404

Chain of Custody Record

TestAmerica
THE LEADER IN ENVIRONMENTAL TESTING

Client Information

Client Contact: Dr. James Rosenblum
Company: CH2M Hill, Inc.
Address: 12377 Merit Drive Suite 1000
City: Dallas
State, Zip: TX, 75251
Phone: 248-939-3216(Tel)
Email: james.rosenblum@ch2m.com
Project Name: OWRB Study Phase II
Site:

Sampler: Jarrod Maly
Phone: 580 541 0319
Due Date Requested:
TAT Requested (days):
PO #:
WO #:
Project #: 49013620
SSOW#:

Lab PM: Gambill, Jennifer
E-Mail: jennifer.gambill@testamericainc.com
Carrier Tracking No(s):
COC No:
Page: Page of
Job #:

Analysis Requested

Preservation Codes:
A - HCL, B - NaOH, C - Zn Acetate, D - Nitric Acid, E - NaHSO4, F - MeOH, G - Amchlor, H - Ascorbic Acid, I - Ice, J - DI Water, K - EDTA, L - EDA
M - Hexane, N - None, O - AsNaO2, P - Na2O4S, Q - Na2SO3, R - Na2S2O3, S - H2SO4, T - TSP Dodecahydrate, U - Acetone, V - MCAA, W - pH 4-5, Z - other (specify)
Other:

Woods County Lower OSage

Sample Identification	Sample Date	Sample Time	Sample Type (C=comp, G=grab)	Matrix (W=water, S=solid, O=waste/oil, BT=Tissue, A=Air)	Field Filtered Sample (Yes or No)	Perform MS/MSD (Yes or No)	200.7 Custom Metals	Hardness	Alkalinity & Bicarbonate	TDS / pH	Chloride / Sulfate / Bromide / Fluoride	Nitrate / Nitrite	BTEX	DRO	GRO	TOC	Phosphorus	Gross Alpha / Beta	Gamma Spec NORM	Total Number of containers	Special Instructions/Note:
			Preservation Code:																		
NORM (1)	9-13	1030A	G	W																	
Gross Alpha/Beta (1)	9-13	1030A	G	W																	
Alk/IC/pH (3)	9-13	1030A	G	W																	
Metals/Hardness (1)	9-13	1030A	G	W																	
TOC (1)	9-13	1030A	G	W																	
BTEX/GRO (6)	9-13	1030A	G	W																	
TDS (1)	9-13	1030A	G	W																	
DRO (2)	9-13	1030A	G	W																	
phosphorus (1)	9-13	1030A	G	W																	
			G	W																	

Loc: 490
159194

Possible Hazard Identification
☐ Non-Hazard ☐ Flammable ☐ Skin Irritant ☐ Poison B ☐ Unknown ☐ Radiological

Sample Disposal (A fee may be assessed if samples are retained longer than 1 month)
☐ Return To Client ☐ Disposal By Lab ☐ Archive For ____ Months

Deliverable Requested: I, II, III, IV, Other (specify)

Special Instructions/QC Requirements:

Empty Kit Relinquished by: Owen Mills Date: 8-8-18 Time: 10:52 Method of Shipment: Hand delivered

Relinquished by	Date/Time	Company	Received by	Date/Time	Company
Jarrod Maly	9-13	DrB	Fed Ex		
			Received by: [signature]	09-14-2018 10:20	TA-NAS
			Received by		

Custody Seals Intact: Δ Yes Δ No
Custody Seal No.:
Cooler Temperature(s) °C and Other Remarks: 12.4

Ver: 08/04/2016

Appendix C
Regulatory Considerations

TITLE 165: CORPORATION COMMISSION
CHAPTER 10: OIL AND GAS CONSERVATION

Effective September 14, 2018

Last Amended
The Oklahoma Register
Volume 35, Number 24
September 4, 2018 publication
Pages 705 - 2322

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CHAPTER 10. OIL AND GAS CONSERVATION

[**Authority:** 52 O. S. §§ 86.2 through 320, 528 through 614]

[**Source:** Codified 12-31-91]

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SUBCHAPTER 1. ADMINISTRATION

PART 1. GENERAL PROVISIONS

PART 3. SURETY

PART 5. SPACING

PART 7. MARKET DEMAND

PART 9. PURCHASERS AND TRANSPORTERS

PART 1. GENERAL PROVISIONS

165:10-1-1. Purpose

The rules of this Chapter were promulgated in furtherance of the public policy and statutory laws of the State of Oklahoma to prevent the waste of oil and gas, to assure the greatest ultimate recovery from the State's reservoirs, to protect the correlative rights of all interest owners, and to prevent pollution.

165:10-1-2. Definitions

The following words and terms, when used in this Chapter, shall have the following meaning unless the context clearly indicates otherwise:

"Agent" means any person authorized by another person to act for him.

"Aquifer" means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

"Area of exposure" means an area within a circle constructed with the point of escape of poisonous gas (hydrogen sulfide) as its center and the radius of exposure as its radius.

"Associated gas" means any gas produced from a Commission ordered combination oil and gas reservoir in which allowed rates of production are based upon volumetric withdrawals.

"BS&W" means basic sediment and water which is that portion of fluids and/or solids that settle in the bottom of storage tanks and/or treating vessels and is unsaleable to the first purchaser in its present form. BS&W usually consists of water, paraffin, sand, scale, rust, and other sediments.

"Barrel" means 42 (U.S.) gallons at 60 F at atmospheric pressure.

"Basic sediment pit" means a pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank.

"Blowout" means the uncontrolled escape of oil or gas, or both, from any formation.

"Blowout preventer" means a heavy casinghead control fitted with special gates and/or rams which can be closed around the drill pipe or which completely closes the top of the casing.

"Blowout preventer stack" means the assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casinghead.

"Business day" means a day that is not a Saturday, Sunday, or legal holiday.

"Carrier", or **"transporter"**, or **"taker"** means any person moving or transporting oil or gas away from a lease or from any common source of supply.

"Casing pressure" means the pressure within the casing or between the casing and tubing at the wellhead.

"Choke manifold" means an assembly of valves, chokes, gauges, and lines used to control the rate of flow from the well when the blowout preventers are closed.

"Closure" means the practice of dewatering, trenching, filling, leveling, terracing, and/or vegetating a pit site after its useful life is reached in order to restore or reclaim the site to near its original condition.

"Commercial disposal well" means a well where the operator receives and disposes of produced water or any deleterious substance from multiple well owners/operators and receives compensation for these services and where the operator's primary business objective is to provide these services.

"Commercial pit" is a disposal facility which is authorized by Commission order and used for the disposal, storage, and handling substances or soils contaminated by deleterious substances produced, obtained, or used in connection with drilling and/or production operations. This does not include a disposal well pit.

"Commercial recycling facility" means a facility that is authorized by Commission order to recycle materials defined as deleterious substances in OAC 165:10-1-2. Such substances must undergo at least one treatment process and must be recycled into a marketable product for resale and/or have some beneficial use. This definition does not include the reuse of drilling mud that was previously utilized in drilling or plugging operations.

"Commercial soil farming" means the practice of soil farming or land applying drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling of a well or wells at an off-site location. Multiple applications to the same land are likely.

"Commission" means the Corporation Commission of the State of Oklahoma.

"Common source of supply" or **"pool"** means "that area which is underlaid or which, from geological or other scientific data, or from drilling operations, or other evidence, appears to be underlaid by a common accumulation of oil and/or gas; provided that, if any such area is underlaid, or appears from geological or other scientific data or from drilling operations, or other evidence, to be underlaid by more than one common accumulation of oil or gas or both, separated from each other by strata of earth and not connected with each other, then such area shall, as to each said common accumulation of oil or gas or both, shall be deemed a separate common source of supply." [52. O.S.A. §86.1(c)].

"Completion/fracture/workover pit" means a pit used for temporary storage of spent completion fluids, frac fluids, workover fluids, drilling fluids, silt, debris, water, brine, oil scum, paraffin, or other deleterious substances which have been cleaned out of the wellbore of a well being completed, fractured, recompleted, or worked over.

"Condensate" means a liquid hydrocarbon which:

(A) Was produced as a liquid at the surface,

(B) Existed as gas in the reservoir, and

(C) Has an API gravity greater than or equal to fifty degrees, unless otherwise proven.

"Conductor casing" means a casing string which is often set and cemented at a shallow depth to support and protect the top of the borehole from erosion while circulating and drilling the surface casing hole.

"Conservation Division" means the Division of the Commission charged with the administration and enforcement of the rules of this Chapter.

"Contingency plan" is a written document which provides for an organized plan of action for alerting and protecting the public within an area of exposure following the accidental release of a potentially hazardous volume of poisonous gas such as hydrogen sulfide.

"Contractor" means any person who contracts with another person for the performance of prescribed work.

"Cubic foot of gas" means the volume of gas contained in one cubic foot of space at an absolute pressure of 14.65 pounds per square inch and at a temperature of 60°F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle's Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge.

"Date of completion" means:

(A) For an oil well, the date that the well first produces oil into the lease tanks through permanent wellhead equipment.

(B) For a gas well, the date of completion of a gas well is the date that gas is capable of being delivered to a pipeline purchaser.

(C) For a well, which does not produce either oil or gas, is the date on which attempts to obtain production from the well cease.

"Day" means a period of 24 consecutive hours. For reporting purposes, it shall be from 7:00 a.m. to 7:00 a.m. the following day.

"Deleterious substances" means any chemical, salt water, oil field brine, waste oil, waste emulsified oil, basic sediment, mud, or injurious substance produced or used in the drilling, development, production, transportation, refining, and processing of oil, gas and/or brine mining.

"Design mud weight" means the planned drilling mud weight to be used. This mud weight is used in the design of the casing strings.

"Design wellhead pressure" means the maximum anticipated wellhead pressure which is expected to be experienced on the inside of the casing string and on wellhead equipment. This pressure is used to design the casing string and to select wellhead equipment with sufficient working pressure rating.

"Development" means any work which actively looks toward bringing in production, such as erecting rigs, building tankage, drilling wells, etc.

"Directional drilling" means intentional changing of the direction of the well from the vertical.

"Director of Conservation" means the person in official charge of the Conservation Division.

"Discharge" means the release or setting free by any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of substances.

"Distressed well" means a well authorized by Commission order to produce at an unrestricted rate in the interest of public safety due to technical difficulties which temporarily cannot be controlled.

"Diverter" means a device attached to the wellhead to close the vertical access and direct any flow into a line away from the rig. Diverters differ from blowout preventers in that flow is not stopped but rather the flow path is redirected away from the rig.

"Duly authorized representative" means, for the purpose of underground injection well applications, that person or position having a responsibility for the underground injection well.

"Emergency pit" means a pit used for the storage of excessive or unanticipated amounts of fluids during an immediate emergency situation in the drilling or operation of a well, such as a well blowout or a pipeline rupture. This does not include a spill prevention structure required by local, state, or federal regulations.

"Enhanced recovery operation" means the introduction of fluid or energy into a common source of supply for the purpose of increasing the recovery of oil therefrom according to a plan which has been approved by the Commission after notice and hearing.

"Enhanced recovery well" means a well producing in an enhanced recovery operation in accordance with Commission order.

"Exchangeable Sodium Percentage (ESP)" is the relative amount of the sodium ion present on the soil surface, expressed as a percentage of the total Cation Exchange Capacity (CEC). Since the determination of CEC is time consuming and expensive, a practical and satisfactory correlation between the Sodium Adsorption Ratio (SAR) and ESP was established. The SAR is defined elsewhere in this Section. ESP can be estimated by the following empirical formula:

$$ESP = \frac{100 \quad (-0.0126 + 0.01475 \times SAR)}{1 + (-0.0126 + 0.01475 \times SAR)}$$

"Exempted aquifer" means an aquifer or its portion that meets the criteria in the definition of "underground source of drinking water" or in the definition of "treatable water", but which has been exempted according to the procedures in 165:5-7-28 and 165:10-5-14.

"Facility" means, for the purposes of 165:10-21-15, any building(s), parts of a building, equipment, property, or vehicles that are actively engaged in the reuse, recycling, or ultimate destruction of deleterious substances pursuant to 68 O.S. Supp. 1986, §2357.14-§2357.20.

"Field" means the general area underlaid by one or more common sources of supply.

"Flare pit" means a pit which contains flare equipment and which is used for temporary storage of liquid hydrocarbons which are sent to the flare but are not burned due to equipment malfunction. Flare pits may be used in conjunction with tank batteries or wells.

"Flowing well" means any well from which oil or gas is produced naturally and without artificial lifting equipment.

"Fresh water strata" means a strata from which fresh water may be produced in economical quantities.

"Gas" means any petroleum hydrocarbon existing in the gaseous phase.

(A) Casinghead gas means any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(B) Dry gas or dry natural gas means any gas produced in which there are no appreciable hydrocarbon liquids recoverable by separation at the wellhead.

(C) Condensate gas means any gas which is produced with condensate as defined as "condensate".

"Gas allowable" or **"allowable gas"** means the amount of natural gas authorized to be produced from any well by order of the Commission or as provided by statute.

"Gas lift" means any method of lifting liquid to the surface by injecting gas into the well bore from which production is obtained.

"Gas repressuring" means the injection of gas into a common source of supply to restore or increase the gas energy of a reservoir.

"GOR (Gas/Oil Ratio)" means the ratio of the gas produced in standard cubic feet to one barrel of oil produced during any stated period. Condensate and load oil excepted under 165:10-13-6 shall not be considered as oil for purposes of determining GOR.

"Hardship well" means a well authorized by Commission order to produce at a specified rate because reasonable cause exists to expect that production below said rate would damage the well and cause waste.

"Hydraulic fracturing operations" means operations on a well wherein fluid is applied for the express purpose of initiating or propagating fractures in a target geologic formation.

"Hydrogen sulfide gas (H_2S)" means a toxic poisonous gas with a chemical composition of H_2S which is sometimes found mixed with and produced with fluids from oil and gas wells.

"Hydrologically sensitive area" means a principal bedrock aquifer, the recharge or potential recharge area of a principal bedrock aquifer, or an unconsolidated alluvium or terrace deposit, according to the Oklahoma Geological Survey "Maps Showing Principal Groundwater Resources and Recharge Areas in Oklahoma" or other maps approved by the Commission.

"Hydrostatic head" or **"hydrostatic pressure"** means the pressure which exists at any point in the wellbore due to the weight of the column of fluid or gas above that point.

"Illegal gas" means gas which has been produced within the State from any well or wells in violation of any rule, regulation, or order of the Commission, as distinguished from gas produced within the State not in violation of any such rule, regulation, or order which is "legal gas".

"Illegal oil" means oil which has been produced within the State from any well or wells in violation of any rule, regulation or order of the Commission, as distinguished from oil produced within the State not in violation of any such rule, regulation, or order which is "legal oil".

"Intermediate casing" means the casing string or strings run after setting the surface casing and prior to setting the production string or liner.

"Kick" means the intrusion of formation liquids or gas that results in an increase in circulation pit volume. Without corrective measures, this condition can result in a blowout.

"Land application" is the application of deleterious substances and/or soils contaminated by deleterious substances to the land for the purpose of disposal or land treatment; also known as soil farming.

"Lease allowable" means the total of the allowables of the individual wells on the lease.

"Liner" means a length of casing used downhole as an extension to a previously installed casing string to case the hole for further drilling operations and/or for producing operations.

"Meter" means an instrument for measuring and indicating or recording the volumes of gases or liquids.

"Mud" means any mixture of water and clay or other material as the term is commonly used in the industry.

"Multi-well system" means two or more wells that have intersecting wellbores or laterals.

"Multiple zone completion" means the completion of any well so as to permit the production from more than one common source of supply, with such common sources of supply completely segregated.

"Noncommercial pit" means an earthen pit which is located either on-site or off-site and is used for the handling, storage, or disposal of deleterious substances or soils contaminated by deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste. This does not include a disposal well pit.

"Normal pressure" means a formation pore pressure, proportional to depth, which is roughly equal to the hydrostatic pressure gradient of a column of salt water (.465 psi/ft).

"Off-site reserve pit" means a pit located off-site which is used for the handling, storage, or disposal of drilling fluids and/or cuttings.

"Oil" or **"crude oil"**, means, for purposes of these regulations, any petroleum hydrocarbon, except condensate, produced from a well in liquid form by ordinary production methods.

"Oil allowable" or **"allowable oil"** means the amount of oil authorized to be produced from any well by order of the Commission.

"Operator" means the person who is duly authorized and in charge of the development of a lease or the operation of a producing property.

"Overage" means the oil or gas delivered to a carrier, transporter, or taker in excess of the allowable set by the Commission for any given period.

"Owner" means the person or persons who have the right to drill into and to produce from any common source of supply, and to appropriate the production either for himself, or for himself and others.

"Person" means any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, fiduciary, or representative of any kind, and shall include the plural.

"Plug" means the closing off, in a manner prescribed by the Commission, of all oil, gas, and waterbearing formations in any producing or nonproducing wellbore before such well is abandoned.

"Pollution" means the contamination of fresh water or soil, either surface or subsurface, by salt water, mineral brines, waste oil, oil, gas, and/or other deleterious substances produced from or obtained or used in connection with the drilling, development, producing, refining, transporting, or processing of oil or gas within the State of Oklahoma.

"Pool" See "common source of supply".

"Potential" means the properly determined capacity of a well to produce oil or gas, or both, under conditions prescribed by the Commission.

"Primary well" means a wellbore that, as part of a multi-well system, serves as the conduit through which oil and gas is produced to the surface.

"Producer" See "Operator" or "Owner".

"Production casing" means the casing string set above or through the producing zone of a well which serves the purpose of confining and/or producing the well production fluids.

"Productivity index" means the daily production of oil in barrels per unit pressure differential between the static reservoir pressure and the stabilized flowing pressure during flow at a stated rate.

"Proration period" means:

(A) The proration period for any well, other than an unallocated gas well, shall be one calendar month which shall begin at 7 a.m. on the first day of such month and end at 7 a.m. on the first day of the next succeeding month unless otherwise specified by order of the Commission.

(B) The proration period for any unallocated gas well shall be one calendar year which shall begin at 7:00 a.m. the first day of such year and end at 7:00 a.m. on the first day of the next succeeding year unless otherwise specified by order of the Commission.

"Public area" means a dwelling place, a business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can reasonably be expected to be populated by humans.

"Public street" or **"road"** means any federal, state, county, or municipal street or road owned or maintained for public access or use.

"Public water supply well(s)" or **"public water well(s)"** means wells in a system for the provision to the public of water for human consumption through pipes or other constructed conveyances, and which wells are identified in a database maintained by the Oklahoma Department of Environmental Quality.

"Purchaser" or **"transporter"** means any person who acting alone or jointly with any person or persons, via his own, affiliated or designated carrier, transporter, or taker, shall directly or indirectly purchase, take, or transport by any means whatsoever or otherwise remove from any lease, oil or gas, and/or other hydrocarbons produced from any common source of supply in this State, excepting royalty portions from leases owned by that person.

"Radius of exposure" means that radius constructed with the point of escape of poisonous (hydrogen sulfide) gas as its starting point and its length calculated by use of the Pasquill-Gifford equations.

"Reclaimed water" means wastewater from municipal wastewater treatment and/or public water supply treatment plants that has gone through various treatment processes to meet specific water quality criteria with the intent of being used in a beneficial manner.

"Reclaimer" or **"reclamation plant"** includes any person licensed by the Oklahoma Tax Commission pursuant to 68 O.S.§1015.1 who reclaims or salvages or in any way removes or extracts oil from waste products associated with the production, storage, or transportation of oil including, but not limited to BS&W, tank bottoms, pit and waste oil, and/or waste oil residue.

"Recomplete" or **"recompletion"** means any operation to:

(A) Convert an existing well from an injection well or disposal well, to a producing well, or

(B) Add or change common sources of supply in an existing well.

"Recycling" is the reuse, processing, reclaiming, treating, neutralizing, or refining of materials and by-products into a product of beneficial use which, if discarded, would be deleterious substances.

"Recycling/reuse pit" means a pit which is used for the recycling or reuse of deleterious substances, is located off-site, and is operated by the generator of the waste.

"Re-enter" or **"re-entry"** is the act of entering a plugged well for the purpose of utilizing said well for the production of oil or gas, for the disposal of fluids therein, for a service well, or for the salvaging of tubing or casing therefrom.

"Regular mail" means first class United States Mail, postage prepaid, and includes hand delivery. Wherever in OAC 165:10 a person is directed to mail by regular mail, such directive shall not preclude mailing by restricted mail.

"Remediation pit" means a pit which is used for the handling, storage, or disposal of deleterious substances and/or soils contaminated by deleterious substances which are relocated to the pit for the purpose of remediating a site which is known to be or suspected to be causing pollution.

"Reserve pit" or **"circulation pit"** means a pit located either on-site or off-site which is used in conjunction with a drilling rig for the handling, storage, or disposal of drilling fluids and/or cuttings.

"Reservoir" See "common source of supply".

"Reservoir pressure" means the static or stabilized pressure in pounds per square inch existing at the face of the formation of an oil or gas well.

"Reuse" is the introduction (or reintroduction) into an industrial, manufacturing, or disposal process of a material which would otherwise be classified as a deleterious substance. A material will be considered "used or reused" if it is either:

(A) Employed as an ingredient (including use as an intermediate) in an industrial, manufacturing, or disposal process to make or recover a product.

(B) Employed in a particular function or application as an effective substitute for a commercial product or non-deleterious substance.

"Rotating head" means a rotating, pressure sealing device used in drilling operations utilizing air, gas, foam, or any other drilling fluid whose hydrostatic pressure is less than the formation pressure.

"Secretary" means the duly appointed and qualified Secretary, Assistant Secretary or Acting Secretary of the Commission, or any person appointed by the Commission to act as such Secretary during the absence, inability, or disqualification of the Secretary to act.

"Separator" means any apparatus for separating oil, gas, and water as they are produced from a well at the surface.

"Service well" means a well that, as part of a multi-well system, is used for drilling laterals, stimulation, or maintenance, or functions in any capacity other than as a conduit to the surface for the production of oil and gas.

"Slick spot" means a small area of soil having a puddled, crusted, or smooth surface and an excess of exchangeable sodium. The soil is generally silty or clayey, is slippery when wet, and is low in productivity.

"Slit trench" means a pit or bermed area at the drilling site used for the temporary storage of drilling fluids and/or cuttings to provide access for equipment to remove the contents off site.

"Sodium Adsorption Ratio (SAR)" means the index which indicates the relative abundance of sodium ions in solution as compared to the combined concentration of calcium and magnesium ions. It is calculated as follows:

$$SAR = \frac{(Na\ ppm/23.0)}{\text{sq. root of } [\ \{(Ca\ ppm/20.02) + (Mg\ ppm/12.16)\} / 2]}$$

where Na=Sodium
Ca=Calcium
Mg=Magnesium

"Soil farming" means the application of oilfield drilling or produced wastes to the soil for the purpose of disposing of the waste without being a detriment to water or land; also known as land application.

"Spill containment pit" mean a permanent pit which is used for the emergency storage of oil and/or saltwater spilled as a result of any equipment malfunction.

"Subnormal pressure" means the formation pore pressure, proportional to depth, which is less than a hydrostatic pressure gradient of .465 psi/ft.

"Sulfide stress cracking" means the cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

"Surface casing" means the first casing string designed and run to protect the treatable water formations and/or control fluid or gas flow from the well.

"Tank bottoms" means the liquids and/or solids in that portion of a storage facility below the sales line or connection that are unsaleable to the crude oil first purchaser in its present form. Tank bottoms may consist of a combination of several elements including, but not limited to, oil, BS&W, and treating fluids.

"Treatable water" means, for purposes of setting surface casing and other casing strings, subsurface water in its natural state, useful or potentially useful for drinking water for human consumption, domestic livestock, irrigation, industrial, municipal, and recreational purposes, and which will support aquatic life, and contains less than 10,000 mg/liter total dissolved solids or less than 5,000 ppm chlorides. Treatable water includes, but is not limited to, fresh water.

"Trenching" means the practice of constructing trenches in or adjacent to a pit for the purpose of relocating all or a portion of the solids so as to facilitate closure.

"Truck wash pit" means a pit used for the temporary storage of fluids generated from the washing or cleaning of a motor vehicle, trailer or container used to transport or store deleterious substances.

"Ultimate destruction" means the treatment of a deleterious substance such that both its weight and volume remaining for disposal have been substantially reduced, and there is no demonstrated process or technology commercially available to further reduce its weight and volume and remove or reduce its harmful properties, if any. For the purposes of demonstrating a substantial reduction in weight and volume, any aqueous portion separated from the balance of a waste that meets drinking water standards or is evaporated into the ambient air shall count toward the weight and volume reduction.

"Underage" means the volume of allowable oil or gas not actually delivered to a carrier, transporter, or taker during any given proration period.

"Underground Source of Drinking Water (USDW)" means an aquifer or its portion which:

(A) Supplies any public water system; or

(B) Contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(C) Is not an exempted aquifer.

"Unit operations" means a unit consisting of a portion of a lease, a lease, or more than one lease or portions thereof which covers contiguous lands containing one or more common sources of supply which has been approved by Commission order as a unit for the purpose of unitized management, after notice and hearing.

"Vacuum" means pressure below the prevailing pressure of the atmosphere.

"Waste" means:

(A) As applied to the production of oil, in addition to its ordinary meaning, "shall include economic waste, underground waste, including water encroachment in the oil or gas bearing strata; the use of reservoir energy for oil producing purposes by means or methods that unreasonably interfere with obtaining from the common source of supply the largest ultimate recovery of oil; surface waste and waste incident to the production of oil in excess of transportation or marketing facilities or reasonable market demands." [52 O.S.A., 86.2]

(B) As applied to gas, in addition to its ordinary meaning, shall include economic waste; "the inefficient or wasteful utilization of gas in the operation of oil wells drilled to and producing from a common source of supply; the inefficient or wasteful utilization of gas in the operation of gas wells drilled to and producing from a common source of supply; the production of gas in such quantities or in such manner as unreasonably to reduce reservoir pressure or unreasonably to diminish the quantity of oil or gas that might be recovered from a common source of supply; the escape, directly or indirectly, of gas from oil wells producing from a common source of supply into the open air in excess of the amount necessary in the efficient drilling, completion or operation thereof; waste incident to the production of natural gas in excess of transportation and marketing facilities or reasonable market demand; the escape, blowing, or releasing, directly or indirectly, into the open air, of gas from well productive of gas only, drilled into any common source of supply, save only such as is necessary in the efficient drilling and completion thereof; and the unnecessary depletion or inefficient utilization of gas energy contained in a common source of supply." [52 O.S.A. §86.3]

(C) The use of gas for the manufacture of carbon black or similar products predominately carbon, except as specifically authorized by the Commission, shall constitute waste.

(D) The flaring of tail gas at gasoline, pressure maintenance, or recycling plants where a market is available.

"Waste oil" shall include, but not be limited to, crude oil or other hydrocarbons used or produced in the process of drilling for, developing, producing, or processing oil or gas from wells, oil retained on cuttings as a result of the use of oil-based drilling muds, or any residue from any oil storage facility on a producing lease or on a commercial disposal operation or pit. The term "waste oil" shall not include any refined hydrocarbons to which lead has been added.

"Waste oil residue" means that portion of waste oil remaining after treatment and after the saleable liquids and water have been extracted. Waste oil residue is a type of waste oil.

"Well log" or **"well record"** means a systematic, detailed and correct record of formations encountered in the drilling of a well.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 97000002); Amended at 16 Ok Reg 842, eff 1-5-99 (emergency RM 980000020); Amended at 16 Ok Reg 2190, eff 7-1-99 (980000034); Amended at 17 Ok Reg 1860, eff 7-1-00 (RM 200000002); Amended at 24 OK Reg 1785, eff 7-1-07 (RM 200700004); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002) Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-1-3. Scope of rules

All rules of general application in this Chapter promulgated to prevent waste, assure the greatest ultimate recovery from the reservoirs of this state, protect the correlative rights of all interests, and to prevent pollution shall be effective throughout the State of Oklahoma and be in force in all pools except as amended, modified, altered, or enlarged in specific individual pools by orders now in effect or hereafter issued by the Commission.

165:10-1-4. Citation effective date

(a) These rules shall be cited as OAC Title 165 Chapter 10 (OAC 165:10).

(b) The effective date of the rules of this Chapter is as set out below:

(1) Order No. 937 - Effective 06/16/15
(2) Order No. 1299 - Effective 08/20/17
(3) Order No. 1986 - Effective 01/05/22
(4) Order No. 6251 - Effective 04/12/33
(5) Order No. 6252 - Effective 04/15/33
(6) Order No. 6393 - Effective 07/19/33
(7) Order No. 6394 - Effective 07/20/33
(8) Order No. 7263 - Effective 04/10/34
(9) Order No. 8229 - Effective 10/31/33
(10) Order No. 17528 - Effective 01/24/45
(11) Order No. 19334 - Effective 10/24/46
(12) Order No. 29232 - Effective 10/06/54
(13) Order No. 30712 - Effective 09/09/55
(14) Order No. 44297 - Effective 04/01/61
(15) Order No. 47397 - Effective 12/01/61
(16) Order No. 53568 - Effective 12/08/63
(17) Order No. 53749 - Effective 01/03/64
(18) Order No. 62481 - Effective 05/11/66
(19) Order No. 62631 - Effective 06/01/66
(20) Order No. 63817 - Effective 10/04/66
(21) Order No. 64203 - Effective 11/10/66

(22) Order No. 64207 - Effective 12/01/66
(23) Order No. 65747 - Effective 05/05/67
(24) Order No. 66006 - Effective 06/08/67
(25) Order No. 66778 - Effective 09/05/67
(26) Order No. 67113 - Effective 10/09/67
(27) Order No. 67379 - Effective 11/06/67
(28) Order No. 69103 - Effective 06/01/68
(29) Order No. 69104 - Effective 06/01/68
(30) Order No. 69340 - Effective 07/01/68
(31) Order No. 70704 - Effective 01/03/69
(32) Order No. 75248 - Effective 07/01/69
(33) Order No. 77627 - Effective 01/01/70
(34) Order No. 78830 - Effective 01/01/70
(35) Order No. 78831 - Effective 01/01/70
(36) Order No. 79460 - Effective 04/01/70
(37) Order No. 79461 - Effective 04/01/70
(38) Order No. 80401 - Effective 06/01/70
(39) Order No. 80402 - Effective 06/01/70
(40) Order No. 81221 - Effective 08/01/70
(41) Order No. 81222 - Effective 08/01/70
(42) Order No. 83168 - Effective 01-01-71
(43) Order No. 84223 - Effective 04-01-71
(44) Order No. 84224 - Effective 04-01-71
(45) Order No. 84318 - Effective 03-29-71
(46) Order No. 85138 - Effective 06-01-71
(47) Order No. 85139 - Effective 06-01-71
(48) Order No. 87730 - Effective 01-01-72
(49) Order No. 87829 - Effective 01-01-72
(50) Order No. 93381 - Effective 10-05-72
(51) Order No. 93382 - Effective 10-05-72
(52) Order No. 94418 - Effective 01-01-73
(53) Order No. 96671 - Effective 04-01-73
(54) Order No. 87829 - Effective 01-01-72
(55) Order No. 94418 - Effective 01-01-73
(56) Order No. 102096 - Effective 01-01-74
(57) Order No. 109595 - Effective 01-01-75
(58) Order No. 117899 - Effective 03-01-76
(59) Order No. 128534 - Effective 03-01-77
(60) Order No. 128781 - Effective 03-01-77
(61) Order No. 138348 - Effective 03-01-78
(62) Order No. 151077 - Effective 03-23-79
(63) Order No. 161968 - Effective 01-03-80
(64) Order No. 164345 - Effective 03-17-80
(65) Order No. 164346 - Effective 02-14-80
(66) Order No. 164347 - Effective 02-14-80
(67) Order No. 165935 - Effective 04-01-80
(68) Order No. 185407 - Effective 03-09-81
(69) Order No. 185890 - Effective 03-16-81
(70) Order No. 211505 - Effective 03-30-82
(71) Order No. 228675 - Effective 01-01-83
(72) Order No. 230515 - Effective 01-01-83
(73) Order No. 230781 - Effective 01-01-83
(74) Order No. 246797 - Effective 01-01-84
(75) Order No. 250273 - Effective 01-01-84
(76) Order No. 250466 - Effective 01-01-84
(77) Order No. 260734 - Effective 07-01-84
(78) Order No. 290210 - Effective 01-09-86
(79) Order No. 292212 - Effective 02-10-86
(80) Order No. 299185 - Effective 06-12-86
(81) Order No. 302126 - Effective 10-08-86

(82) Order No. 303650 - Effective 10-02-86
(83) Order No. 304257 - Effective 10-16-86
(84) Order No. 305211 - Effective 11-07-86
(85) Order No. 311872 - Effective 05-06-87
(86) Order No. 312391 - Effective 05-14-87
(87) Order No. 310755 - Effective 06-01-87
(88) Order No. 313445 - Effective 06-12-87
(89) Order No. 313446 - Effective 07-09-87
(90) Order No. 313660 - Effective 06-17-87
(91) Order No. 313932 - Effective 06-25-87
(92) Order No. 314001 - Effective 06-27-87
(93) Order No. 313446 - Effective 07-09-87
(94) Order No. 315275 - Effective 08-19-87
(95) Order No. 320171 - Effective 12-21-87
(96) Order No. 320741 - Effective 01-08-88
(97) Order No. 320742 - Effective 01-08-88
(98) Order No. 321123 - Effective 01-21-88
(99) Order No. 323847 - Effective 05-01-88
(100) Order No. 325144 - Effective 05-02-88
(101) Order No. 326275 - Effective 06-27-88
(102) Order No. 326343 - Effective 06-01-88
(103) Order No. 326344 - Effective 06-01-88
(104) Order No. 327514 - Effective 07-01-88
(105) Order No. 327515 - Effective 07-01-88
(106) Order No. 329661 - Effective 08-26-88
(107) Order No. 329662 - Effective 08-26-88
(108) Order No. 329663 - Effective 08-26-88
(109) Order No. 334130 - Effective 01-04-89
(110) Order No. 337475 - Effective 03-31-89
(111) Order No. 337476 - Effective 03-31-89
(112) Order No. 339860 - Effective 05-07-89
(113) Order No. 341102 - Effective 08-25-89
(114) Order No. 341103 - Effective 08-14-89
(115) Order No. 346071 - Effective 03-29-90
(116) Order No. 346107 - Effective 03-30-90
(117) Order No. 355458 - Effective 03-20-91
(118) Order No. 355461 - Effective 03-20-91
(119) Order No. 355463 - Effective 03-20-91
(120) Order No. 355471 - Effective 03-21-91
(121) Order No. 364345 - Effective 06-25-92
(122) Order No. 364382 - Effective 06-25-92
(123) Order No. 368110 - Effective 08-28-92
(124) Order No. 372796 - Effective 06-25-93
(125) Order No. 381632 - Effective 07-11-94
(126) Order No. 381755 - Effective 07-11-94
(127) Order No. 387223 - Effective 10-20-94
(128) RM No. 950000023 - Effective 07-01-96
(129) RM No. 950000024 - Effective 07-01-96
(130) RM No. 950000025 - Effective 07-11-96
(131) RM No. 960000008 - Effective 07-01-96
(132) RM No. 960000009 - Effective 07-01-96
(133) RM No. 960000018 - Effective 10-15-96
(134) RM No. 970000002 - Effective 07-01-97
(135) RM No. 970000011 - Effective 07-01-98
(136) RM No. 970000025 - Effective 07-11-98
(137) RM No. 980000013 - Effective 07-15-98
(138) RM No. 980000016 Emergency, - Effective 03-30-98
(139) RM No. 980000017 Emergency, - Effective 03-30-98
(140) RM No. 980000020 Emergency, - Effective 01-05-99
(141) RM No. 980000033 - Effective 07-01-99

(142) RM No. 980000034 - Effective 07-01-99
(143) RM No. 980000035 - Effective 07-01-99
(144) RM No. 990000010 - Emergency, - Effective 12-28-99
(145) RM No. 200000002 - Effective 07-01-00
(146) RM No. 200000009 - Emergency, - Effective 11-02-00
(147) RM No. 200000009 - Permanent, - Effective 05-11-01
(148) RM No. 200100005 - Effective 07-01-01
(149) RM No. 200100006 - Effective 07-01-01
(150) RM No. 200100009 - Emergency, - Effective 01-14-02
(151) RM No. 200200017 - Effective 07-01-02
(152) RM No. 200300001 - Effective 07-01-03
(153) RM No. 200400006 - Effective 07-01-04
(154) RM No. 200600012 - Effective 07-01-06
(155) RM No. 200600013 - Emergency, - Effective 10-04-06
(156) RM No. 200700004 - Effective 07-01-07
(157) RM No. 200800003 – Effective 07-11-08
(158) RM No. 200900001 – Effective 07-11-09
(159) RM No. 201000003 – Effective 07-11-10
(160) RM No. 201100004 – Emergency, - Effective 05-19-11
(161) RM No. 201000007 – Effective 07-11-11
(162) RM No. 201200005 – Effective 07-01-12
(163) RM No. 201300001 - Effective 07-01-13
(164) RM No. 201400002 – Effective 09-12-14
(165) RM No. 201500001 – Effective 08-27-15
(166) RM No. 201600001 – Effective 08-25-16
(167) RM No. 201600019 – Effective 09-11-17

[**SOURCE:** Amended at 16 Ok Reg 2206, eff 7-1-99 (RM 980000033); Amended at 19 Ok Reg 1947, eff 7-1-02 (RM 200200017); Amended at 20 Ok Reg 1479, eff 4-24-03 (emergency); Amended at Ok Reg 1543, eff 7-1-03 (RM 200300001); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001)]; Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-1-5. Conservation Division [RESERVED]

165:10-1-6. Duties and authority of the Conservation Division

(a) It shall be the duty of the Conservation Division to administer and enforce the statutes of this State and the rules, regulations, and orders of the Commission relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing, and storage of oil and gas, and to administer and enforce the applicable provisions of the Natural Gas Policy Act of 1978.

(b) The Conservation Division shall have the right at all times to go upon and inspect any oil and gas properties, pipelines, tank farms, refineries, and other processing plants and pump stations for the purpose of making any investigations or tests to ascertain whether the rules, regulations, and orders of the Commission are being complied with, and shall report to the Commission any violation thereof.

(c) The Conservation Division may require the testing or retesting of any oil, gas, injection, or disposal well upon 48-hour notice. Until the test is completed or excused, no allowable will be assigned the well and the purchaser or taker of oil or gas from such well shall not run oil or gas until authorized by the Conservation Division.

(d) The Director of the Conservation Division may administratively reclassify a well according to the gas-oil ratio as specified in 165:10-13-2 if the retesting of a well pursuant to this Section indicates a change in the original gas-oil ratio. This administrative reclassification shall only be used for allowable or priority purposes pursuant to 165:10-17-12. The operator shall be notified in writing by the Conservation Division within 15 days of the effective date of any change in classification.
(e) If the operator of the well which has been reclassified objects to said reclassification, he may file a written objection with the Conservation Division within 15 days of receiving notice of the reclassification. At the same time that the objection is filed, the operator shall file an application and notice setting cause for hearing with the Court Clerk Commission. The notice shall be published one time at least 15 days prior to the hearing in a newspaper of general circulation published in Oklahoma County and in a newspaper of general circulation published in each county in which lands embraced in the application are located.
(f) The Conservation Division shall have access to all well records, wherever located. All companies, operators, drilling contractors, drillers, service companies, or other persons shall permit any authorized employee of the Commission to come upon any lease or property operated or controlled by them, and to inspect the records of wells; provided, that information so obtained shall be confidential. Any person who attempts, by means of any threat or violence, to deter or prevent any authorized employee of the Commission from performing any duty hereunder shall be prosecuted to the fullest extent of the law.
(g) Upon request of the Conservation Division, service companies or other persons shall furnish and file reports and records showing gun perforating, hydraulic fracturing, cementing, shooting, chemical treatment, and all other service operations on any well.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 26 Ok Reg 2498, eff 7-11-09, (RM 200900001)]

165:10-1-7. Prescribed forms
(a) Required Conservation Division forms may be submitted to the Commission on forms supplied by the Commission or on xerographic copies of Commission forms or by operator computer generated forms. Operator computer generated forms will be printed from Commission designed files made available to operators via the electronic Bulletin Board Service (BBS), Internet (World Wide Web) or magnetic disk. Operator computer generated forms must contain the exact language and wording of Commission forms. Any alteration of Commission forms language and wording may subject the signature party and/or operator to perjury charges.
(b) The following Conservation Division forms are prescribed for filing purposes:
(1) **Form 1000 - Notice of Intention to Drill application:** Operator shall file Form 1000 before any oil, gas, injection, disposal, service well or stratigraphic test hole is drilled, recompleted, re-entered or deepened. Such notice shall include the name(s) and address(es) of the surface owner(s) of the land upon which the well is to be located. The Commission shall process the application and mail a copy of the permit to drill or re-enter to the surface owner(s). Upon approval, the operator will have eighteen months to commence the permitted operations. A six month extension may be granted without fee providing the Conservation Division staff determines that no material change of condition has occurred, if written request for such extension is received from the operator prior to the expiration of the original permit. Only one extension may be granted. A copy of the approved permit shall be posted at the well site. [Reference 165:10-3-1 and 165:10-1-25 and OAC 165:10-7-31]

(2) **Form 1000B - Application to Drill Deep Anode Groundbeds:** Form 1000B is required to be filed for wells drilled for deep anode groundbeds as required by OAC 165:10-7-14. The purpose of Commission Form 1000B is to ensure groundwater is being protected in construction of the deep anode groundbed. [Reference 165:10-7-14]

(3) **Form 1000S – Application for seismic operations:** A permit for seismic operations must be obtained. The applicant must post a $50,000 bond with the Surety Department in the Oil and Gas Conservation Division. The application must also be accompanied with a pre-plat of the project area. [Reference 165:10-7-31]

(4) **Form 1001 - Notification of Intention to Plug:** Operator shall file notice on Form 1001 five days prior to plugging operations and shall notify the appropriate Conservation Division District Office before work is started. If the well is an exhausted producer, list OTC assigned county and lease number. If the Intent to Plug is cancelled, the operator shall notify the Commission by letter. [Reference 165:10-11-4 and 165:10-11-6]

(5) **Form 1001A - Notification of Spudding of New Well:** Operator shall file a Form 1001A with the Conservation Division within 14 days of spudding a new well or reentering a previously plugged well. [Reference 165:10-3-2]

(6) **Form 1002A - Well completion report:** Operator shall furnish a complete well record on Form 1002A within 60 days after completion of operations to drill, recomplete, re-enter, or convert to injection or disposal well. Effective for both dry hole and/or producer. If well is an oil or gas producer, list OTC assigned county and lease number. Gas-oil ratio must be shown when Form 1002A is filed. List on a 24-hour basis both oil and gas. [Reference 165:10-3-25]

(A) **Oil well:** GOR less than 15,000:1

(B) **Gas well:** GOR 15,000:1 or more

(7) **Form 1002B - Confidential Filing of Electric Logs:** Operator shall file Form 1002B within 60 days from the earlier of the date of completion of the well or the date of the running of the last formation evaluation type wire line log to hold logs confidential for one year period. Optional extension for six months may be requested by operator in writing to the Technical Services Department of the Conservation Division. [Reference 165:10-3-26]

(8) **Form 1002C - Cementing Report to accompany Well Completion Report:** Operator shall file Form 1002C with the Well Completion Report (Form 1002A) describing all cementing operations on surface, intermediate, and production casing strings, including multistage cementing jobs. The form shall be completed and signed by employees of both the operator and the cementing company. [Reference 165:10-3-4(i)]

(9) **Form 1003 - Plugging Record:** Operator will file Form 1003 within 30 days after plugging operations are completed. The Form 1003 is to be mailed or e-mailed to the appropriate Conservation Division District Office. Form 1003 shall be completed and signed by employees of both the operator and the cementer. If a depleted producer, list OTC assigned county and lease number. [Reference 165:10-11-6 and 165:10-11-7]

(10) **Form 1003A - Notice of Temporary Exemption from Well Plugging:** Form 1003A shall be filed with the appropriate Conservation Division District Office. [Reference 165:10-11-3 and 165:10-11-9]

(11) **Form 1004 - Monthly Report of Unallocated Natural Gas Wells Production:** Each operator of the required meter under 165:10-17-5 shall file a monthly well report on Form 1004 with the Commission of all natural gas volumes transferred through the meter for the preceding month, by the last day of the month following such transfer. List formation name plus OTC assigned county and lease number. If more than one meter, the operator of each shall file this form. [Reference 165:10-1-47]

(12) **Form 1004B - Notice of Gas Purchase Curtailments:** In any month wherein a first purchaser or first taker has a market demand/supply imbalance and must curtail purchases or takes in compliance with 165:10-17-

12, Form 1004B shall be filed by said first purchaser or first taker with the Conservation Division. [Reference 165:10-17-12]

(13) **Form 1005 - Monthly Report of Purchasers** (Gas: subject to field rules): [Reference 165:10-1-47 and 165:10-15-1]

(A) **GAS:** Each operator of the required meter or meters under 165:10-17-5 shall complete computer-generated Form 1005, and return a copy to the Conservation Division indicating the gas amounts transferred through the meter for the preceding month on allocated and special allocated gas wells.

(B) **OIL:** Each first purchaser, or first taker of oil from wells and projects which are capable of producing in excess of their maximum assigned allowables, must complete computer-generated Form 1005 and return a copy to the Conservation Division indicating the amount of oil taken from each well or unit for the preceding month.

(14) **Form 1006 - Surety bond for oil, gas, injection, or disposal wells:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division a surety bond ($25,000.00) or other present alternate surety, Form 1006A or 1006C. Operator must file the original copy only with a copy of the power of attorney from the bonding company. The name and address of the Oklahoma resident service agent shall be endorsed on the bond form. [Reference 165:10-1-10 and 165:10-1-12]

(15) **Form 1006A - Financial Statement for oil, gas, injection or disposal wells:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division a verifiable financial statement (minimum net worth $50,000.00 within the State of Oklahoma) or other present alternate surety, Form 1006 or 1006C. Operator must file an original copy on Form 1006A, which must be updated annually from the last filing date. [Reference 165:10-1-10 and 165:10-1-11]

(16) **Form 1006B - Operator Agreement to plug oil, gas, and service wells within the State of Oklahoma:** Operator shall agree to plug well(s) in compliance with the Commission rules. This agreement must accompany the operator's elective choice of surety (Form 1006, 1006A, or 1006C). The operator is required to file a Form 1006B with the Conservation Division once every twelve (12) months. [Reference 165:10-1-10, 165:10-1-11, 165:10-1-12, 165:10-1-13, and 165:10-1-14]

(17) **Form 1006BR - Recycling, Reclaiming Operator's Agreement to Close the Reclaiming Facility:** Prior to operating a recycling or reclaiming facility the operator shall file an agreement to close the facility in compliance with OCC rules. This agreement must accompany the application for certification (Form 1020A). [Reference 165:10-8-5]

(18) **Form 1006BR-A – Operator agreement to close hydrocarbon recycling/reclaiming facility:** Operators of hydrocarbon recycling/reclaiming facilities are required to file agreements with the Commission concerning closure of such facilities. [Reference 165:10-8-5]

(19) **Form 1006BR-B - Surety for closure of hydrocarbon recycling/reclaiming facility:** Operators of hydrocarbon recycling/reclaiming facilities are required to file surety with the Commission for closure and reclamation of such facilities. [Reference 165:10-8-5]

(20) **Form 1006BT-A – Operator's agreement to close, reclaim and remediate truck wash pit:** Operators of truck wash pits are required to file agreements with the Commission regarding closure of such pits. [Reference 165:10-7-33]

(21) **Form 1006BT-B - Surety for closure of truck wash pits:** Operators of truck wash pits are required to file surety with the Commission for closure, reclamation and remediation of such pits. [Reference 165:10-7-33]

(22) **Form 1006C - Irrevocable commercial letter of credit:** Prior to drilling and/or operating a well, the operator shall furnish the Conservation Division an irrevocable commercial letter of credit ($25,000.00) or other present alternate surety, Form 1006A or 1006.

Operator must file the original copy with the bank seal affixed. A letter of credit must be valid for at least a one year period. [Reference 165:10-1-10 and 165:10-1-13]

(23) **Form 1006D - Affidavit of well plugging costs:** An operator may submit an affidavit on Form 1006D to the Conservation Division concerning the operator's statewide plugging liability. The Commission may approve Category B surety in an amount less than $25,000.00 for an operator whose statewide plugging liability is less than $25,000.00. The Form 1006D must be properly executed by a duly licensed pipe pulling and well plugging company and such Form must be acceptable to the Conservation Division. [Reference 165:10-1-10, 165:10-1-12, 165:10-1-13 and 165:10-1-14]

(24) **Form 1006S – Operator's agreement to plug seismic shot holes within the State of Oklahoma:** Prior to commencing seismic operations the operator shall file an agreement to plug shot holes in accordance with Commission rules. This agreement must accompany the financial surety guarantee. [Reference 165:10-7-31]

(25) **Form 1006SB - Surety bond for seismic shot hole plugging within the State of Oklahoma:** Before commencing any seismic operation that requires the drilling of shot holes, those companies actually doing the work in the field must secure a bond in the amount of $50,000.00. Seismic companies must file the original Form 1006SB only with a copy of the power of attorney from the bonding company. The name and address of the Oklahoma resident service agent shall be endorsed on the bond form. Form 1000S shall be filed with the bond. [Reference 165:10-11-6 and 165:10-7-31]

(26) **Form 1007A - IBM operator annual unallocated natural gas wells survey:** Annual Survey Form 1007A will be furnished to all operators at the end of each calendar year. The form shall be updated by the operator as of December 31 notifying the Commission of any new wells, wells sold (to whom and address), or abandoned since the last 1007A was filed. Original shall be forwarded to Conservation Division by February 15th for the previous year's activity. List OTC assigned county and lease number (if not imprinted). [Reference 165:10-17-16]

(27) **Form 1010 - Application for Cancelled Underage:** Operator shall file, within 30 days for oil, and six months for special allocated and allocated gas from the date of cancellation, to reinstate cancelled underage; stating reason for this request and notifying all offset operators. List OTC assigned county and lease number. [Reference 165:10-13-10 and 165:10-17-9]

(28) **Form 1011-Multi-Zone lease runs report:** If there are two or more common sources of supply that are produced through a well or wells on the same lease or drilling and spacing unit and that are not commingled, production from each common source of supply shall be separately produced, measured and/or accounted for to the Commission. If one or more of the zones produced are classified as oil for allowable purposes, the operator is required to submit to the Conservation Division a multi-zone report on Form 1011 showing the production from each oil-bearing common source of supply on or before the last day of the succeeding proration period. [Reference 165:10-13-7]

(29) **Form 1012 - Fluid Injection Report:** Operators shall file Form 1012 with the Conservation Division by January 31 of each year covering the previous calendar year (January 1 through December 31) on all enhanced recovery projects, pressure maintenance projects, noncommercial salt water disposal wells, LPG storage wells, authorized waterfloods and gas repressuring projects for each UIC well. The completed form will list well identification including API number, the Commission order or permit number, injection volume and pressure, etc., as required on the form. No UIC well is to be operated for injection or disposal unless the Form 1012 is filed by the above date. [Reference 165:10-5-7].

(30) **Form 1012C – Commercial disposal well fluid disposal report:** Operators of commercial disposal wells shall file Form 1012C with the Conservation Division by January 31 and July 31 of each year for the

previous six-month period. The completed form will list well identification including API number, the Commission order or permit number, disposal volume and pressure, etc. as required on the form. No commercial disposal well is to be operated unless the Form 1012C is filed by the above dates. [Reference 165:10-5-7].

(31) **Form 1012D – Daily volume and pressure report for disposal wells within areas of interest:** Operators of wells authorized for disposal within areas of interest designated by the Oil and Gas Conservation Division shall submit Form 1012D containing daily volumes and pressures to the Manager of the Pollution Abatement Department at a minimum on a weekly basis or as designated by such Manager. [Reference 165:10-5—7]

(32) **Form 1013 - Application for adjusting an allowable for an Excessive Water Exemption or Reservoir Dewatering Oil Spacing unit:** An operator in an unallocated oil pool may be permitted to produce at a full capacity allowable rate, provided that the water- oil ratio at the well is greater than or equal to 3:1 as an excessive water exemption. To qualify for the reservoir dewatering oil spacing unit allowable shown on Appendix J, the operator must provide data to show that the water - oil ratio is greater than 1:1. The operator shall submit a production test on Form 1013 to the Conservation Division. [Reference 165:10-15-1, 165:10-15-16, 165:10-15-17 and 165:10-15-18].

(33) **Form 1014 - Application for Permit to Use Earthen Pit, noncommercial disposal or enhanced recovery well pit used for temporary storage of saltwater, or pit associated with commercial disposal well surface facility:** The operator of a proposed off-site reserve pit, recycling/reuse pit, spill containment pit, remediation pit, noncommercial disposal or enhanced recovery well pit used for temporary storage of saltwater, or pit associated with a commercial disposal well surface facility must submit Form 1014 to the appropriate Conservation Division District Office for approval before constructing or using the pit. [Reference 165:10-7-16, 165:10-7-20 and 165:10-9-3]

(34) **Form 1014A – Commercial facility report:** A report that operators of hydrocarbon recycling/reclaiming facilities, commercial pits, commercial soil farming sites and commercial recycling facilities are required to submit to the Manager of Pollution Abatement. [Reference 165:10-8-8, 165:10-9-1, 165:10-9-2 and 165:10-9-4]

(35) **Form 1014C - Chain of custody record/analysis request:** Form 1014C is available for use by Commission personnel when samples are collected for submission to and analysis by a laboratory certified by the Oklahoma Water Resources Board or operated by the State of Oklahoma.

(36) **Form 1014CA - Compliance agreement for land application:** Any person responsible for supervision of land application must submit a compliance agreement to the Commission. [Reference 165:10-7-19 and 165:10-7-26]

(37) **Form 1014CR – Application for commercial recycling facility construction:** After a Commission order is obtained, Form 1014CR must be submitted for approval to the Manager of Pollution Abatement prior to the construction of the commercial recycling facility authorized by the order. [Reference OAC 165:10-9-4]

(38) **Form 1014CS - Application for Commercial Soil Farming:** For a commercial soil farming site that has an order to operate, the operator shall submit a Form 1014CS to the Pollution Abatement Department for approval prior to commencing soil farming. [Reference 165:10-9-2]

(39) **Form 1014D - Application for Surface Discharge or for reclaiming and/or recycling of produced water:** Each application for surface discharge of produced water or for reclaiming and/or recycling of produced water must be submitted to the appropriate Conservation Division District Office on Form 1014D in quadruplicate. Applications will be processed within five business days. [Reference 165:10-7-17 or 165:10-7-32]

(40) **Form 1014F - Application for permit to use flow back water pit with capacity in excess of 50,000 barrels:** The operator of a proposed flow back

water pit with a capacity in excess of 50,000 barrels must submit the Form 1014F to and obtain the approval of the Manager of Field Operations or obtain the issuance of a Commission order before constructing or using the pit. [Reference 165:10-7-16]

(41) **Form 1014HD - Notice for Disposal of Hydrostatic Test Water:** Companies wishing to discharge water as required by OAC 165:10-7-17, used to test a pipeline, tank, etc. must submit a Form 1014HD to the appropriate Conservation Division District Office and the Pollution Abatement Department for prior approval. [Reference 165:10-7-17]

(42) **Form 1014L - Surface Owner Permission for Land Application:** Each application for land application must include an original Form 1014L, whereby the applicable surface owner gives permission for the applicant to land apply certain deleterious substances to a specific property. [Reference 165:10-7-19 and 165:10-7-26]

(43) **Form 1014LA – Designation of land application agent:** A notarized affidavit designating any agent of an operator for land application must be submitted to the Commission. [Reference 165:10-7-17, 165:10-7-19 and 165:10-7-26]

(44) **Form 1014LC – Letter of credit for land application:** Persons who contract to land apply materials are required to file surety with the Commission. [Reference 165:10-7-10]

(45) **Form 1014N - Application for Commercial Pit Construction:** After a Commission order is obtained, Form 1014N must be submitted for approval by the Manager of Pollution Abatement prior to the construction of each commercial pit authorized by the order. [Reference 165:10-9-1]

(46) **Form 1014P – Annual report for surface discharge:** An annual report is required to be submitted to the Commission by April 1 of each year on Form 1014P concerning surface discharges of produced water. Current (within three month) analyses of the produced water and soil from the discharge plot must be attached to the annual report. [Reference 165:10-7-17]

(47) **Form 1014R – Post land application report:** A post land application report shall be submitted by the operator or the operator's agent to the Manager of Pollution Abatement within ninety (90) days of the completion of land application. [Reference 165:10-7-19 and 165:10-7-26]

(48) **Form 1014RW – Application for permit to use reclaimed water in oil and gas operations:** Each application for a permit to use reclaimed water in oil and gas operations must be submitted to the Manager of Field Operations on Form 1014RW. [Reference OAC 165:10-7-34]

(49) **Form 1014S - Application for Land Application:** Each application for land application of materials must be submitted to the Pollution Abatement Department on Form 1014S. An original is required. The applicant must be the operator of the well or other operator responsible for generating the waste to be land applied, except that a commercial pit operator may also apply in case of emergency or for the purpose of facilitating repair or closure, and the Oklahoma Energy Resources Board or its contractor may apply in cases where there is no responsible party. The Form 1014S shall be processed within five business days of submission of all required or requested information. [Reference 165:10-7-19 and 165:10-7-26]

(50) **Form 1014SB – Surety bond for land application:** Persons who contract to land apply materials are required to file surety with the Commission. [Reference 165:10-7-10]

(51) **Form 1014T – Application for permit to use truck wash pit:** The operator of a proposed truck wash pit must submit Form 1014T to the Manager of Field Operations for the Conservation Division and obtain a permit before constructing or using the pit. [Reference 165:10-7-33]

(52) **Form 1014W - Application for waste oil or drill cuttings use by County Commissioners:** Application to apply waste oil, waste oil residue, crude oil contaminated soil or freshwater drill cuttings must be made by any Board of County Commissioners on Form 1014W. The Form 1014W is

required to be submitted by electronic mail_to the appropriate District Manager. [Reference 165:10-7-22 and 165:10-7-28]

(53) **Form 1014X - Application for waste oil or drill cuttings use by operators:** Application to apply waste oil, waste oil residue, crude oil contaminated soil or freshwater drill cuttings must be made by any operator on Form 1014X. The Form 1014X is required to be submitted by electronic mail or mailed to the appropriate District Manager. [Reference 165:10-7-27 and 165:10-7-29]

(54) **Form 1015 - Application for Administrative Approval to Dispose of or Inject Water into Well(s) or to amend existing orders authorizing injection for enhanced recovery, saltwater disposal or LPG storage well(s):** Applicant shall file an original of the application and one complete set of attachments with the Commission on Form 1015. When requesting approval to dispose of or inject water into wells, applicant will also furnish copies of the application on Form 1015 to the surface owner and with regard to injection or disposal wells with a requested injection rate of less than five thousand barrels per day to each operator of a producing spacing unit or well within one-half (1/2) mile of the proposed noncommercial injection or disposal well location, and to each operator of a producing spacing unit or well within one (1) mile of either a proposed noncommercial injection or disposal well location with a requested injection rate of five thousand barrels per day or more or a proposed commercial disposal well location within five (5) days of the filing of the application and applicant will submit an affidavit of delivery or mailing to the Commission not later than five days after the application is filed. In addition, if the application involves a proposed horizontal injection or disposal well, a copy of the application for approval shall be served by the applicant within five (5) days of the date the application is filed by regular mail or delivered to each operator of a producing spacing unit or well within one-half (1/2) mile of the lateral of the proposed noncommercial injection or disposal well with a requested injection rate of less than five thousand barrels per day, and to each operator of a producing spacing unit or well within one (1) mile of the lateral of either a proposed noncommercial injection or disposal well with a requested injection rate of five thousand barrels per day or more or a proposed commercial disposal well. Further, if the application involves a proposed commercial disposal well, a copy of the application for approval shall be served within five (5) days of the date the application is filed by regular mail or delivered to each surface owner and surface lessee of record on each tract of land adjacent and contiguous to the site of the proposed well. Applicant shall file with the Commission proof of publication regarding the notice of application in an Oklahoma County newspaper and a county newspaper in which the well is located. [Reference 165:10-5-2, 165:10-5-5, 165:5-7-27 and 165:5-7-30]

(55) **Form 1015SI - Application for Permit for Simultaneous Injection Well:** Operator shall file original with the Underground Injection Control Department on Form 1015SI. A copy of the form will also be supplied to the operator of any producing lease within one-half (1/2) mile of the proposed injection well. [Reference 165:10-5-15]

(56) **Form 1015T - Application for Injection of Reserve Pit Fluids:** Each application for the on-site injection of reserve pit fluids (i.e., drilling mud fluids or fracture fluids) used in drilling or well completion shall be filed with the Underground Injection Control Department by the well operator on Form 1015T. The original of the application and one complete set of attachments shall be furnished to the Underground Injection Control Department. A copy of the application will also be supplied to the land owner and the operator of any producing lease within one-half (1/2) mile of the proposed well. [Reference 165:10-5-13]

(57) **Form 1015U - Unit-wide application for Injection:** Optionally, the operator can file a unit-wide application for injection (Form 1015U) that fulfills all the requirements of 165:5-7-27 (b) through (e). Upon review

and approval, the operator receives a unit-wide order that allows the operator to file an individual well application (Form 1015) and if it fits the unit-wide criteria, the UIC order can be issued immediately without an additional area of review, notice, or protest period. [Reference 165:5-7-27]

(58) **Form 1016 - Back Pressure Test for Natural Gas Wells:** Operators and/or purchasers, on the Form 1016, will report all single-point and four-point potential tests as required by pool rule orders or general rules. List OTC assigned county and lease numbers and special allocated pool numbers, first date of sales, and complete flow data. [Reference 165:10-17-6 and 165:10-17-7]

(59) **Form 1017 - Guymon-Hugoton Field Gas Well Deliverability Tests:** Operators and/or purchasers of gas in this field shall take deliverability tests between January 1 and August 31 of each year, and on the test sheet Form 1017 file the results with the Commission. List OTC assigned lease number for each well. [Reference Orders No. 17867 and 87291 and 165:10-17-9]

(60) **Form 1019 - Guymon-Hugoton Field Acreage Statement for Gas Wells:** A fact statement as to acreage attributable to each well shall be filed with the Commission on Form 1019 within 30 days of the well completion with a plat or map showing location of the well. List OTC assigned county and lease number. [Reference Order No. 17867 and 165:10-17-9]

(61) **Form 1020A - Application for Certification for the Recycling, Reuse of Deleterious Substances:** Applicant shall file an original Form 1020A with necessary attachments with the Pollution Abatement Department. Form 1020A is filed prior to construction of facility or change of operator. [Reference 165:10-8-1 through 165:10-8-11]

(62) **Form 1021 - Application for Priority Hardship Classification:** The applicant shall file Form 1021 and the necessary attachments with the Technical Services Department for review prior to any hearing for priority one hardship classification. In addition, a formal application for hearing must be filed with the Court Clerk's Office of the Commission. [Reference 165:10-17-12]

(63) **Form 1021A - Application for limited deviation from the priority gas rules:** The applicant shall file Form 1021A and the necessary attachments with the Technical Services Department for review prior to any hearing for deviation from the priority gas rules. In addition, a formal application for hearing must be filed with the Court Clerk's Office of the Commission. [Reference 165:10-17-12]

(64) **Form 1022 - Application to flare or vent gas:** Operator shall file one copy of Form 1022 with the Technical Services Department of the Conservation Division listing OTC assigned county lease number. [Reference 165:10-3-15]

(65) **Form 1022A - Application to operate vacuum pump:** Operator shall file one copy of Form 1022A with the required attachments with the Technical Services Department of the Conservation Division. [Reference 165:10-3-31]

(66) **Form 1023 - Application for multiple completion, multichoke assembly or commingle completion:** Operator will file the original of Form 1023 with the required attachments. List OTC assigned county and lease number. [Reference 165:10-3-35; 165:10-3-39; 165:10-3-37]

(67) **Form 1024 - Packer setting affidavit:** Operator will submit Form 1024 as required. [Reference 165:10-3-35 and pertinent field rules]

(68) **Form 1025 - Packer leakage test:** Operator will submit Form 1025 as required. [Reference 165:10-3-35 and pertinent field rules]

(69) **Form 1027 - Bottom hole pressure test:** Operator, on the pink sheet of Form 1027, shall take BHP tests in the manner and during periods prescribed by special field rules. List OTC assigned county and lease numbers. [Reference Special Field Rules and 165:10-13-3]

(70) **Form 1028 - Application for discovery oil allowable:** Operator shall file Form 1028 with the required exhibits and tests within 30 days of

completion of each new well in a discovery oil pool. [Reference 165:10-15-7]

(71) **Form 1029A - Production or potential test - oil only:** Operator of each newly completed discovery oil well shall file a potential test Form 1029A not later than 30 days after completion of the well. All tests, if requested, shall be witnessed by another operator. [Reference 165:10-15-7].

(72) **Form 1030 - Application for allowable adjustment:** Each operator or other interested parties desiring to adjust the allowable for a well or wells shall file Form 1030 for administrative review and approval. The allowable may be increased, decreased, or transferred as the evidence may indicate for the most efficient rate of production from the well or wells. [Reference 165:10-13-5, 165:10-13-8, 165:10-15-18 and 165:5-7-12]

(73) **Form 1034 - Nominations and purchasers report:** [Reference 165:10-1-36, 165:10-1-37 and 165:10-1-46] **Oil:** Purchasers will furnish nomination data, actual runs from leases, stocks, and other information on Form 1034 to the Conservation Division not later than noon Friday of the week preceding each scheduled market demand hearing. On months in which no market demand hearing is held, Form 1034 shall be filed by the 20th of the month listing crude oil runs for the previous month on line 5 only. Any change in nominations from the previous hearing shall be so indicated on this monthly report.

(74) **Form 1034-G – Gas nominations:** Operators of natural gas wells in special allocated gas pools where well allowable calculations according to special allocated field rules are in effect shall file their pool nominations on Form 1034-G no later than one week prior to the market demand hearing. [Reference 165:10-1-36, 165:10-1-37, 165:10-1-49 and 165:10-17-9].

(75) **Form 1036A – Contempt Citation:** Form 1036A may be issued by Commission personnel regarding the categories of rule violations appearing in Appendices E and F to this Chapter [Reference 165:10-3-17, 165:10-7-7 and 165:10-7-9].

(76) **Form 1040 - Monthly allocation schedule (gas):** Monthly gas schedule Form 1040 will be forwarded to operators by the Conservation Division indicating the status of special allocated gas wells and their current allowables. Operators will inform the Conservation Division of errors, if any, found in Form 1040 as promptly as possible. Additionally, purchasers will receive the monthly schedule and shall return the production from each well as requested. [Reference 165:10-1-47]

(77) **Form 1055 – Application for Pipe Pulling and Well Plugging License:** No person shall contract to pull casing or plug oil, gas, injection, disposal, or other service wells, or contract to salvage casing therefrom, or purchase wells for the purpose of salvaging casing therefrom until a license has been secured from the Commission. [Reference 165:10-11-1]

(78) **Form 1070 - Inventory of authorized existing enhanced recovery wells:** Operators shall file reporting Form 1070 before injecting into any enhanced recovery well. [Reference 165:10-5-3]

(79) **Form 1071 - Inventory of authorized existing disposal wells:** Operators shall file the reporting Form 1071 before disposing into any disposal well. [Reference 165:10-5-3]

(80) **Form 1072 - Notice of termination of injection:** Within 30 days of the termination of injection Form 1072 must be filed. [Reference 165:10-5-7]

(81) **Form 1073 - Notice of transfer of oil or gas well operatorship:** The new operator shall file Form 1073 to notify the Conservation Division of any change of operation of any oil or gas well within 30 days of transfer of the well. [Reference 165:10-1-15]

(82) **Form 1073I - Notice of transfer of underground injection well operatorship:** The new operator shall file Form 1073I to notify the Underground Injection Control Department of any change of operation of any

injection, disposal, enhanced recovery injection or hydrocarbon storage well within 30 days of transfer of the well. [Reference 165:10-5-10]

(83) **Form 1073IMW-Notice of transfer of multiple underground injection well operatorship:** For transfers involving more than 10 underground injection wells, a transferor and transferee may file a single Form 1073IMW with the Conservation Division indicating the transfer of multiple wells. If the Form 1073IMW is used, such Form must be filed with the Conservation Division regarding any change of operations of such wells within 30 days of transfer of the wells. [Reference 165:10-5-10]

(84) **Form 1073MW-Notice of transfer of multiple oil or gas well operatorship:** For transfers involving more than 10 oil or gas wells, a transferor and transferee may file a single Form 1073MW with the Conservation Division indicating the transfer of multiple wells. If the Form 1073MW is used, such Form must be filed with the Conservation Division regarding any change of operations of such wells within 30 days of transfer of the wells. [Reference 165:10-1-15]

(85) **Form 1075 - Mechanical integrity pressure test:** A pressure or monitoring test must be performed on new and existing enhanced recovery injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a Field Inspector. Forms shall be submitted to the Conservation Division's Underground Injection Control Department. [Reference 165:10-5-6]

(86) **Form 1081 - Mineral owners escrow account:** Operator shall file, in quadruplicate, Form 1081 annually on anniversary date of first pooling order issued after effective date of Senate Bill 299 (7-1-84) and shall include all applicable orders issued during the twelve-month reporting period. [Reference 165:10-25-1 through 165:10-25-10]

(87) **Form 1085 - Complaint report:** Form 1085 is used by Commission personnel to report violations of General Rules of the Commission and to report progress on ongoing remedial actions. Copies are sent to all parties concerned with investigation. Form 1085 combines and replaces old Forms 1034 and 1062. [Reference 165:10-7-7]

(88) **Form 1139 - Application for gross production tax exemption:** Operators shall file one copy of Form 1139 with the required attachments with the Technical Services Department of the Conservation Division. [Reference 165:10-21-75 through 165:10-21-80]

(89) **Form 1534 - Application for tax rebate:** Operators shall file one original of Form 1534 with the required attachments with the Technical Services Department of the Conservation Division. To obtain the tax exemption of the gross production tax, the operator shall forward a copy of the Commission approval to the Oklahoma Tax Commission, together with any other data required by that agency. [OTC Rule 10.030.03] [Reference 165:10-21-23, 165:10-21-37, 165:10-21-57, 165:10-21-67 and 165:10-21-82.2]

(90) **Form 1535 - Application for classification of reservoir dewatering project for exemption of sales tax on electricity used for such operations and application for state sales tax exemption for electricity sold for operations involving enhanced recovery methods on a spacing unit or lease:** Operators shall file one original of Form 1535 with the required attachments with the Technical Services Department of the Conservation Division. To obtain the exemption of sales tax on the sale of electricity and associated delivery and transmission used for reservoir dewatering operations, or for a state sales tax exemption for electricity sold for operations involving enhanced recovery methods on a spacing unit or lease, the operator shall contact the Director's Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, Ok. 73194. [Reference 165:10-21-90 through 165:10-21-92 and 165:10-21-95 through 165:10-21-97]

(91) **Form 2000BF - AAI Oversight Qualification:** The Applicant shall file one (1) original of Form 2000BF with the Brownfield Program of the Conservation Division listing the qualifications as per AAI of each

Environmental Professional who will work on the site. [Reference 165:10-10-1 through 165:10-10-14]

(92) **Form 2001BF – Brownfield Applicant Eligibility:** The applicant shall file one (1) original of Form 2001BF with the Brownfield Program of the Conservation Division. This Form is filed to demonstrate applicant's eligibility to be in the Brownfield program. [Reference 165:10-10-1 through 165:10-10-14]

(93) **Form 2002BF - Consent to Entry:** The applicant shall file one (1) original of Form 2002BF with the Brownfield Program of the Conservation Division. This Form is the landowner's permission for applicant and their contractors to enter the property for assessment and cleanup work. Copies will be sent to all parties concerned with the assessment and/or cleanup. [Reference 165:10-10-1 through 165:10-10-14]

(94) **Form 2003BF - Application for Brownfield Site Eligibility and Assessment:** The applicant shall file one (1) original of Form 2003BF with the Brownfield Program of the Conservation Division for all sites applicant is entering into the program. This Form provides necessary information on the site. This Form can be used by public, quasi-public, and non-profit entities to request a free Targeted Brownfield Assessment of a site that has been approved as eligible for the Brownfield program. [Reference 165:10-10-1 through 165:10-10-14]

(95) **Form 2005BF - Brownfield Certificate of No Action Necessary:** The Form 2005BF will be issued by the Commission to the Brownfield Applicant, after the Brownfield staff has made a no action necessary decision. The applicant must file the Certificate of No Action Necessary in the office of the county clerk where the site is located, provide a copy to the landowner if the landowner is not the applicant, and submit a file-stamped copy to the Oklahoma Corporation Commission within 30 days. [Reference 165:10-10-1 through 165:10-10-14]

(96) **Form 2006BF - Brownfield Certificate of Completion:** The Form 2006BF will be issued by the Commission to the Brownfield Applicant, after the Brownfield staff has made a final inspection of the site and review of the project following a remedial action. The applicant must file the Certificate of Completion and any land use restrictions in the office of the county clerk where the site is located, provide a copy to the landowner if the landowner is not the applicant, and submit a file-stamped copy to the Oklahoma Corporation Commission within 30 days. [Reference 165:10-10-1 through 165:10-10-14]

(97) **Form 3000NGS – Application for Investigation and/or Abatement of Seeping Natural Gas:** An owner of property which has seeping natural gas shall file an application with the Commission regarding the Commission's investigation and/or abatement of the seeping natural gas. [Reference 165:10-12-9]

(98) **Form 4000WIP – Well impact report:** If an operator has evidence that its well(s) have been impacted by hydraulic fracturing operations, the operator may report the occurrence by electronic mail to the appropriate Conservation Division District Office within 24 hours of discovery. The operator must use Form 4000WIP to report the occurrence. [Reference 165:10-3-10]

[**SOURCE:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 13 Ok Reg 2373, eff 7-1-96; Amended at 13 Ok Reg 2381, eff 7-1-96; Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 970000002); Amended at 15 Ok Reg 2989, eff 7-15-98 (RM 980000013); Amended at 16 Ok Reg 2206, eff 7-1-99 (RM 980000033); Amended at 18 Ok Reg 226, eff 11-2-00 (emergency RM 200000009); Amended at 18 Ok Reg 1035, eff 5-11-01 (permanent RM 200000009); Amended at 19 Ok Reg 1947, eff 7-1-02 (RM 200200017); Amended at 20 Ok Reg 1479, eff 4-24-03 (emergency);Amended at 20 Ok Reg 1543, eff 7-1-03 (RM 200300001); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-

11-11 (RM 201000007); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001)]; Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001)]; Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 3. SURETY

165:10-1-10. Operator's agreement; Category A and Category B surety

(a) "Any person who drills or operates any well for the exploration, development or production of oil or gas, or as an injection or disposal well, within this State, shall furnish in writing, on forms approved by the Corporation Commission, his agreement to drill, operate and plug wells in compliance with the rules and regulations of the Commission and the laws of this state, together with evidence of financial ability to comply with the requirements for plugging, closure of surface impoundments, removal of trash and equipment as established by the rules of the Commission and by law." [52 O.S. § 318.1] Any operator violating this Section may be fined up to $500.00. To establish evidence of financial ability, the Commission shall require:

(1) Category A surety which shall include a financial statement listing assets and liabilities and including a general release that the information may be verified with banks and other financial institutions. The statement shall prove a net worth of not less than $50,000.00 in U.S. dollars; or

(2) Category B surety shall include an irrevocable commercial letter of credit, cash, a cashier's check, a certificate of deposit, bank joint custody receipt, other approved negotiable instrument, or a blanket surety bond. Except as provided in (3) of this subsection, the amount of such Category B surety shall be in the amount of $25,000.00 in U.S. dollars but may be set higher at the discretion of the Director of the Conservation Division. The Commission is authorized to establish Category B surety in an amount greater than $25,000.00 in U.S. dollars based upon the past performance of the operator and its insiders and affiliates regarding compliance with the laws of this state, and compliance with any rules promulgated thereto including but not limited to the drilling, operation and plugging of wells, closure of surface impoundments, or removal of trash and equipment. Any such Category B surety shall constitute an unconditional promise to pay and be in a form negotiable by the Commission.

(3) The Commission may grant Category B surety in an amount less than $25,000.00 in U.S. dollars to an operator whose statewide well plugging liability is less than $25,000.00 in U.S. dollars. Said Category B surety shall be in an amount that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, an operator is responsible. Statewide well plugging liability shall be documented by an affidavit filed on Form 1006D and shall be properly executed by a duly licensed pipe pulling and well plugging company and shall be approved by the Conservation Division. Said affidavit shall state, among other things, an estimated cost of plugging, closure, and removal operations for each well in accordance with 165:10-11-3 through 165:10-11-8 inclusively and shall be accompanied by a Form 1000 (Intent to Drill) if the estimate involves a proposed well or by a Form 1002A (Completion Report) if the estimate involves a well that is a producing, injection, or disposal well. The estimated cost shall not include any salvage value as to recoverable casing, tubing, or well head equipment. The total statewide well plugging liability of an operator utilizing this Category B surety shall be kept current and shall be increased as additional wells are added to the responsibility of the operator and may be decreased as included wells are plugged and abandoned, but in no event shall exceed $25,000.00 in U.S. dollars unless otherwise ordered by the Commission.

(b) Operators of record as of June 7, 1989, who do not have any outstanding contempt citations or fines and whose insiders or affiliates have no outstanding contempt citations or fines may post Category A surety.

(1) New operators, operators who have outstanding fines or contempt citations and operators whose insiders or affiliates have outstanding contempt citations or fines as of June 7, 1989, shall be required to post Category B surety. Operators who have posted Category B surety and have operated under this type surety and have no outstanding fines at the end of three years may post Category A surety.

(2) Operators using Category A surety who are assessed a fine of $2,000.00 or more and who do not pay the fine within the specified time shall be required to post a Category B surety within 30 days of notification by the Commission.

(c) If a bond is required, the bond shall be executed by a corporate surety authorized to do business in this State and shall be renewed and continued in effect until the conditions have been met or release of the bond is authorized by the Commission.

(d) Irrespective of (a), (b), and (c) of this Section, for good cause shown concerning pollution or improper plugging of wells by an operator posting either Category A or Category B surety or by an insider or affiliate of such operator, the Commission, upon application of the Director of the Conservation Division after notice and hearing, may require the filing of additional Category B surety in an amount greater than $25,000.00 in U.S. dollars but not to exceed $100,000.00 in U.S. dollars. If the Commission has evidence that any person applying to the Commission for authority to operate may not possess a satisfactory compliance history with Commission rules, the Director of the Conservation Division may seek an order of the Commission, issued after application, notice, and hearing, determining whether the person should be authorized to operate.

(e) The agreement (Form 1006B-Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) provided for in (a) of this Section shall provide that if the Commission determines, after notice and hearing, that the person furnishing the agreement has neglected, failed, or refused to plug and abandon, or cause to be plugged and abandoned, or replug any well or has neglected, failed or refused to close any surface impoundment or remove or cause to be removed trash and equipment in compliance with the rules of this Chapter, then the person shall forfeit from his bond, letter of credit, or negotiable instrument or shall pay to this State, through the Commission for deposit in the State Treasury, a sum equal to the cost of plugging the well, closure of any surface impoundment, or removal of trash and equipment. The Commission may cause the remedial work to be done, issuing a warrant in payment of the cost thereof drawn against the monies accruing in the State Treasury from the forfeiture or payment. Any monies accruing in the State Treasury by reason of a determination that there has been a noncompliance with the provisions of the agreement (Form 1006B) or the rules and regulations of the Commission, in excess of the cost of remedial action ordered by the Commission, shall be credited to the Conservation Fund. The Commission shall also recover any costs arising from litigation to enforce this provision if the Commission prevails. Provided, before a person is required to forfeit or pay any monies to the State pursuant to this Section, the Commission shall notify the person at his last-known address of the determination of neglect, failure, or refusal to plug or replug any well, or close any surface impoundment, or remove trash and equipment, and said person shall have ten days from the date of notification within which to commence remedial operations. Failure to commence remedial operations shall result in forfeiture or payment as provided in this subsection. If the operator is a corporation, association, partnership, limited liability company or any entity other than an individual, the operator shall file as part of its Form 1006B a complete list, in tabular form, of the names, addresses, telephone numbers, driver license numbers, and percentages of ownership of all officers, directors, partners or principals of the operator and the insiders and

affiliates of the operator. The operator shall also file as part of its Form 1006B the current names and addresses of all service agents of the operator and the operator's insiders and affiliates. The operator is required to file a Form 1006B with the Conservation Division every twelve (12) months.
(f) No person shall drill or operate any well, or receive an allowable, without complying with the provisions of this Section.
(g) The Commission shall shut in, without notice, hearing or order of the Commission, the wells of any such person violating the provisions of this Section and such wells shall remain shut in for noncompliance until the required evidence of Category B surety is obtained and verified by the Commission. No taker, transporter, or purchaser of oil or gas shall take, transport, or purchase oil or gas from the wells of any such drillers or operators after receiving a copy of the shut-in order or notice by certified mail of the issuance of such an order.
(h) If title to property or a well is transferred, the transferee shall furnish the evidence of financial ability to plug the well and close surface impoundments required by the provisions of this section, prior to the transfer.
(i) The following words, when used in this Section, shall have the following meaning:
(1) "Affiliate" means an entity which owns twenty percent (20%) or more of the operator, or an entity of which twenty percent (20%) or more is owned by the operator.
(2) "Insider" means officer, director, or person in control of the operator; general partners of or in the operator; general or limited partnership in which the operator is a general partner; spouse of an officer, director, or person in control of the operator; spouse of a general partner of or in the operator; corporation of which the operator is a director, officer, or person in control; affiliate, or insider of an affiliate as if such affiliate were the operator; or managing agent of the operator.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2373, eff 7-1-96; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007)]

165:10-1-11. Financial statement as surety
(a) A plugging agreement shall be accompanied by surety. The surety requirement may be met by furnishing the operator's current financial statement (Form 1006A) to the Conservation Division, which shall be a full statement of the operator's assets and liabilities and shall reflect the operator's total net worth of not less than $50,000.00 in U.S. dollars located in this State.
(b) The value of producing oil and gas leaseholds for which the financial statement stands as surety will be deducted from total net worth unless the financial statement is accompanied by the written appraisal of a recognized independent appraiser of oil and gas properties showing the fair market value of the leasehold interest owned by the operator.
(c) The Director of Conservation may require proof in the form of an appraisal or other proof of the fair market value of any asset listed in the financial statement, and the Director of Conservation may also require proof that the financial statement truly shows the net fair market value of all assets over and above all debts and encumbrances.
(d) A current financial statement shall be filed every twelve (12) months on Form 1006A.
(e) Only one operator's name shall appear on each Form 1006A.
(f) Along with the Form 1006A, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.
(g) The Commission shall reject the operator's Form 1006A if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-12. Corporate surety bond

(a) An operator may file a blanket surety bond in the principal amount of $25,000.00 in U.S. dollars on Form 1006 as surety. In the alternative, the operator may file a surety bond of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternative surety bond shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission.

(b) For purposes of (a) of this Section, an operator may file a surety bond issued by a corporation authorized to issue such bonds in the State of Oklahoma.

(c) The Conservation Division shall not accept a bond unless the surety agrees to give the Conservation Division six months written notice before cancellation of a bond prior to expiration of the bond and evidence furnished of acceptable alternate surety if required.

(d) Only one operator's name shall appear on each Form 1006.

(e) Along with the Form 1006, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.

(f) The Commission shall reject the operator's Form 1006 if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-13. Irrevocable commercial letter of credit

(a) At his option, an operator may file an irrevocable commercial letter of credit of a bank in the sum of $25,000.00 in U.S. dollars on Form 1006C as surety. In the alternative, the operator may file an irrevocable commercial letter of credit of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternative irrevocable commercial letter of credit shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission.

(b) The letter of credit shall be for a term of not less than one year.

(c) The bank issuing the letter of credit shall endorse thereon that the letter of credit shall remain in effect until canceled or revoked by the bank or principal/operator upon six months notice in writing to the Conservation Division and evidence furnished of acceptable alternate surety if required.

(d) Only one operator's name shall appear on each Form 1006C.

(e) Along with the Form 1006C, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.

(f) The Commission shall reject the operator's Form 1006C if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-14. Cashier's check, certificate of deposit, or other negotiable instrument

(a) An operator may deposit cash, a cashier's check, a certificate of deposit, bank joint custody receipt, or other negotiable instrument in the amount of

$25,000.00 in U.S. dollars as surety. In the alternative, the operator may deposit cash, a cashier's check, a certificate of deposit, bank joint custody receipt, or other negotiable instrument of a lesser amount but that is sufficient to cover the total estimated cost of properly plugging and abandoning each and every well, the operations for which, the operator is responsible. Said estimated cost shall be documented on Form 1006D (Affidavit of Well Plugging Cost) for each and every well. Said alternate amount shall be increased upward, but not to exceed $25,000.00 in U.S. dollars, as additional wells are added to the operator's responsibilities, unless otherwise ordered by the Commission. However, any instrument must constitute an unconditional promise to pay and be in the form negotiable by the Commission.

(b) A certificate of deposit shall be for a term of no less than three hundred sixty-five (365) days.

(c) Financial institutions issuing certificates of deposit pursuant to this Section shall do so in the following manner: **"Oklahoma Corporation Commission or Oklahoma Corporation Commission and (Name of the Operator)."** Financial institutions issuing the certificates of deposit shall retain the original documents and copies of the certificates of deposit shall be furnished to the Commission.

(d) Along with the negotiable instruments described in (a) of this Section, an operator is required to file a Form 1006B (Operator's Agreement to Plug Oil, Gas and Service Wells Within the State of Oklahoma) with the Conservation Division.

(e) The Commission shall reject the negotiable instruments described in (a) of this Section if the operator fails to file the documentation required by this Section with the Conservation Division.

[SOURCE: Amended at 13 Ok Reg 2373, eff 7-1-96]

165:10-1-15. Transfer of operatorship of wells

(a) Before the operations of a well can be transferred to a new operator, the following must be submitted:

(1) The new operator, or transferee, must comply with 165:10-1-10 before a change in operator is approved.

(2) Change of operator Form 1073 or Form 1073MW must be signed by both the transferor and transferee, with both stipulating that the facts presented are true and correct as to the area covered and the wells being transferred. The new operator shall file Form 1073 or Form 1073MW to notify the Conservation Division of any change of operation of any oil or gas well within thirty (30) days of transfer of the well. Unless otherwise stated, the new operator assumes all responsibility for the wells specified within the boundaries of the outlined area. For transfers involving more than ten (10) wells, a transferor and transferee may file a single Form 1073MW with the Conservation Division indicating the transfer of multiple wells, provided that such multiple well transfer shall be accompanied by a well list containing the following information regarding each well being transferred:

(A) API number of the well;

(B) Well name and number;

(C) Legal location of the well, described by section, township and range.

(3) The well list may be provided in spreadsheet form, if possible, and may be filed in digital format specified by the Conservation Division. In lieu of the spreadsheet, the transferor and transferee, at their option, may file one Form 1073MW indicating the transfer of multiple wells with an OCC Form 1002A Completion Report attached for each well transferred. Upon review by the Conservation Division, it may require additional information from the transferor and/or the transferee to assist in identifying the specific well(s) being transferred. The additional information may include, but not be limited to, the quarter, quarter, quarter section calls, footages from the south and west quarter section lines, and the drilling and completion dates.

(4) The Conservation Division shall notify both the transferor and transferee in writing within thirty (30) days of the Conservation Division's

approval or disapproval of the transfer of operatorship for the subject well(s).

(5) Compliance with 165:5-7-11 when and if operatorship was designated by orders of the Commission in pooling, increased density, and location exception applications.

(b) Before the operatorship of a well can be transferred to a new operator when the current or former operator is unavailable for signature, one of the following may be submitted as proof of operatorship:

(1) A certified copy of a recorded lease or assignment transferring all rights, title, and interest to the wells described on Form 1073 or Form 1073MW to the new operator.

(2) A certified copy of a journal entry of judgment rendered by a district court of Oklahoma having jurisdiction over the wells described on Form 1073 or Form 1073MW vesting legal title to the new operator.

(3) A certified copy of bankruptcy proceeding by the federal district court having jurisdiction over the wells described on Form 1073 or Form 1073MW.

(c) If an operator is not in compliance with an enforceable order of the Commission, the Conservation Division shall not approve any Form 1073 or Form 1073MW transferring well(s) to said operator until the operator complies with the order. The transferor of the well(s) listed on the Form 1073 or Form 1073MW remains responsible for the well(s) until any transfer is approved by the Commission.

[**SOURCE:** Amended at 13 Ok Reg 2373, eff 7-1-96; Amended in Rule Making 2000000002, eff 7-1-00; Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-1-16. Change of address

Each operator of a well or other facility subject to a permit shall give written notice of his change of address. Such notice shall be sent to the Director of the Conservation Division. It shall be due within 30 days after changing address.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2373, eff 7-1-96]

PART 5. SPACING

165:10-1-20. Spacing [RESERVED]

165:10-1-21. General well spacing requirements

Any well drilled for oil or gas to an unspaced common source of supply the top of which is 2,500 feet or more in depth shall be located not less than 330 feet from any property line or lease line, and shall be located not less than 600 feet from any other producible or drilling oil or gas well when drilling to the same common source of supply; provided and except that in drilling to an unspaced common source of supply the top of which is less than 2,500 feet in depth, the well shall be located not less than 165 feet from any property line or lease line and not less than 300 feet from any other producible or drilling oil or gas well in the same common source of supply; provided, however, that the depth to the top of the common source of supply in the original or discovery well shall be recognized as the depth to the top of the common source of supply for the purpose of this Section; provided further, when an exception to this Section is granted, the Commission may adjust the allowable or take such other action as it deems necessary for the prevention of waste and protection of correlative rights.

[**SOURCE:** Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007)]

165:10-1-22. Drilling and spacing units

(a) The Commission may establish drilling and spacing units in any common source of supply as provided by law, and the special orders creating drilling and spacing units shall supersede the provisions of 165:10-1-21. It shall be the responsibility of any operator who proposes to drill a well to ascertain the existence and provisions of special spacing orders.
(b) The drilling of a well or wells into a common source of supply in an area covered by an application pending before the Commission seeking the establishment of drilling and spacing units is prohibited except by special order of the Commission. However, if an Intent to Drill (Form 1000) has been approved by the Commission and operations commenced prior to the filing of a spacing application, the operator shall be permitted to drill and complete the well without a special order of the Commission.
(c) Standard drilling and spacing units shall be either approximately square or rectangular; if rectangular, the drilling and spacing unit shall consist of two approximately square tracts.
(d) Standard square drilling and spacing units shall be those containing approximately 10, 40, 160, or 640 acres; standard rectangular units shall contain approximately 20, 80, or 320 acres.
(e) The drilling and spacing units within any common source of supply of oil or gas shall be of approximately uniform size and shape. In a combination reservoir, the drilling and spacing units within the oil portion of the reservoir shall be of approximately uniform size and shape, and the drilling and spacing units within the gas portion of the reservoir shall be of approximately uniform size and shape; provided, however, the drilling and spacing units within the gas portion of a combination reservoir along the gas-oil contact line or transition zone may be of nonuniform size and shape.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-1-23. Extension of pool rules
(a) Any application to establish pool rules for a common source of supply shall include the entire common source of supply.
(b) To extend pool rules to a drilling and spacing unit, an application shall be filed and notice provided in the same manner as required to establish pool rules. In the event that more than one set of pool rules are in effect within a field, the Commission shall extend the appropriate pool rules consistent with available geological and engineering reservoir information.

165:10-1-24. Permitted well locations within standard drilling and spacing units
(a) The permitted well location within any standard square drilling and spacing unit shall be the center of the unit. The permitted well locations within standard rectangular drilling and spacing units shall be the centers of alternate square tracts constituting the units (alternate halves of the units); provided, however, a well will be deemed drilled at the permitted location if drilled within the following tolerance areas:
(1) Not less than 165 feet from the boundary of any standard 10-acre drilling and spacing unit or the proper square 10-acre tract within any standard 20-acre drilling and spacing unit.
(2) Not less than 330 feet from the boundary of any standard 40-acre drilling and spacing unit or the proper square 40-acre tract within any standard 80-acre drilling and spacing unit.
(3) Not less than 660-feet from the boundary of any standard 160-acre drilling and spacing unit or the proper square 160-acre tract within any standard 320-acre drilling and spacing unit.
(4) Not less than 1320 feet from the boundary of any standard 640-acre drilling and spacing unit.
(b) The proper square tract of a rectangular drilling and spacing unit established prior to January 1, 1971, for which a slot drilling pattern was prescribed, shall be the northeast quarter and the southwest quarter of the

governmental section, quarter section, or quarter quarter section containing two abutting rectangular drilling and spacing units; provided, slot patterns may be established or re-established upon application, notice, and hearing where consistent with available geological and engineering information when necessary to prevent waste or protect correlative rights.

(c) The permitted well location tolerance areas set out in (a) of this Section shall apply to each standard drilling and spacing unit heretofore or hereafter established, notwithstanding the provisions of any special order of the Commission prescribing a different permitted well location tolerance area; provided, however, this Section shall not affect any adjusted allowable or penalty applied to any well by special order of the Commission prior to the effective date of this Section, nor shall any well heretofore drilled within a then permitted tolerance area be deemed outside the permitted tolerance area by reason of this Section.

(d) Wells drilled offpattern without first obtaining an exception after notice and hearing by the Commission are hereby prohibited from producing either oil or gas.

(e) Whenever permission is granted to drill a well at a location other than specified in this Chapter, the allowable or production therefrom, or both, may be adjusted for the protection of the correlative rights of all persons entitled to share in the common source of supply.

(f) Unless the order granting a well location exception provides otherwise, the permission to drill the well at the excepted location shall expire twelve (12) months after the date of the order, unless a well was commenced at the excepted location on or before the expiration date. The order granting the well location exception will thereafter expire when the well is plugged, abandoned, or converted.

(g) An application for an emergency order granting a well location exception may be granted if the applicant has obtained the written consent of the operator of each adjoining or cornering tract of land or drilling and spacing unit, currently producing from the same formation, toward which the well location is proposed to be moved. Provided, however, if the applicant is the operator of the well in an adjoining or cornering tract of land or drilling and spacing unit, currently producing from the same formation, toward which the well location is proposed to be moved, the applicant shall obtain the written consent of each working interest owner in such well.

(1) Letters evidencing the written consent of off-set operators and working interest parties as described in this subsection shall be introduced and received into evidence at the time of the emergency hearing and reviewed. Copies of said letters shall be filed with the Court Clerk of the Commission.

(2) If the written consent described in this subsection cannot be obtained, the applicant may send written notice to said non-consenting party giving that party at least five business days notice of the emergency hearing. If said non-consenting party fails to appear, then the emergency application shall be considered and may be granted without the non-consenting party's written consent. The applicant shall file an affidavit of mailing with the Court Clerk to prove the mailing of the five day notice.

(h) If a spacing application is currently pending and the applicant or any party who owns the right to drill needs to commence a well prior to issuance of the spacing order, the applicant or party shall obtain an emergency order to commence such well and an emergency location exception order if:

(1) The proposed well is offpattern according to the existing spacing for any formation involved, or

(2) The well is offpattern according to 165:10-1-21 governing well patterns for unspaced areas.

(i) Whenever an order permits an offpattern well with a percentage penalty, the order permitting said well may provide, at the request of a party entitled to notice in the cause, for said party to have the right, at his sole cost and risk, to attend and monitor the initial potential testing and all subsequent annual testing of the proposed offpattern well to ensure proper testing. If the

order permits witnessing of tests as prescribed above, then the order shall further provide that at least five days prior to the initial potential testing and each subsequent annual testing of the proposed well, the operator of the well shall notify, in writing, all parties entitled to notice in the cause who requested to attend and monitor these tests of the date and time upon which said testing shall commence.

[**Source:** Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-1-25. Replacement well

(a) Approval by the Conservation Division of a Notice of Intent to Drill (Form 1000) for a second well to be drilled in a common source of supply in a single drilling and spacing unit as a replacement well may be permitted when:

(1) The replacement well is to be drilled at a location permitted for the common source of supply by either an order or rule of the Commission; and

(2) The operator of the replacement well is either the operator or a working interest owner in the original unit well; and

(3) The Notice of Intent to Drill for the replacement well is accompanied by an affidavit from the operator, stating that on completion of the second well as a commercial producer, the common source of supply in the first well shall be plugged off immediately. The affidavit shall be attached to Notice of Intent to Drill.

(b) A replacement well shall not receive an allowable to produce oil or gas from the same common source of supply as the first well until:

(1) Said common source of supply in the original well in the drilling and spacing unit is plugged off; or

(2) The Commission issues an order authorizing the replacement well as an increased density well for said common source of supply; or

(3) The Commission issues an order reforming the drilling and spacing units in said common source of supply thereby placing the original well and the replacement well in different drilling and spacing units for the common source of supply.

165:10-1-26. Permitted producing well location within an enhanced recovery project

Any well drilled for or used for the production of oil or gas within any enhanced recovery project shall be located not less than 165 feet from the lease or project line, whichever is the outside boundary.

165:10-1-27. Increased density well

Upon application after notice and hearing, the Commission may issue an order permitting one or more additional wells within a drilling and spacing unit, if each additional well will prevent or assist in preventing the various types of waste prohibited by statute or if each additional well will protect or assist in protecting the correlative rights of interest owners in said common source of supply.

165:10-1-28. Geological correlation chart

The chart initially prepared by Phillips Petroleum and maintained by the Oklahoma City Geologic Society entitled "Geologic Section of Oklahoma and Northern Arkansas", along with ensuing revisions, shall be used as a guideline for stratigraphic nomenclature in all oil and gas conservation applications which are submitted to the Commission.

PART 7. MARKET DEMAND

165:10-1-35. Market demand [RESERVED]

165:10-1-36. Regulation, classification, and naming of pools

(a) When the Commission finds, upon notice and hearing, that oil or gas production from any source of supply exceeds the current market demand therefor or finds that the operation of the reservoir should be regulated in order to prevent waste, increase ultimate recovery, or protect correlative rights, the Commission shall thereupon promulgate appropriate pool rules to accomplish such objectives. Where any of the above findings are made by the Commission, the total production from the pool may be restricted and equitable allocation made to the various wells located therein, or the operation of the reservoir may be otherwise regulated and controlled to insure proper and adequate conservation.
(b) Any pool may be classified or reclassified by the Commission, upon hearing, as an oil pool, gas pool, combination pool, or condensate pool. All pool rules so promulgated shall be based on operating and technical data and shall be consistent with the characteristics attributable to each classification.
(c) All oil and gas pools in the State shall be named by the Commission.

165:10-1-37. Determination of market demand

(a) The Commission shall instruct the Director of Conservation to determine the reasonable market demand for oil, gas, and other hydrocarbon products produced in Oklahoma for consumption in and outside the State for the ensuing proration period(s) that can be produced from each common source of supply on a statewide basis without avoidable waste and with equitable participation in production and markets by all operators and other interested parties.
(b) Waste, in addition to its statutory and ordinary meaning, shall include but not be restricted to economic waste, underground waste, surface waste, and waste incident to the production of oil and gas in excess of the transportation or marketing facilities or reasonable market demand.
(c) Reasonable market demand shall include, but not be restricted to, the demand for oil, gas, and other hydrocarbons for reasonable current requirements for current consumption and use within and outside the State, with such adjustment as may be necessary upward or downward to maintain adequate aboveground stocks of crude oil and its products and underground stocks of natural gas, so as to provide a continuous supply of petroleum products to the consumer and essential strategic supplies for national defense.
(d) In determining the reasonable market demand, the Commission may consider:
(1) Any statement communicated to the Commission by any purchaser or taker of oil and gas, stating the amount of oil or gas produced from common sources of supply that such purchaser or taker contemplates or intends to purchase during the period of time involved; or in lieu thereof, the capacity of the purchaser's transportation or marketing facilities which will be, during the time involved, available for transporting and/or marketing the oil or gas that may be produced from common sources of supply.
(2) Official records, reports, and statistical information compiled and kept by the Conservation Division that can be utilized in determining reasonable market demand.
(3) Reports, facts, and materials by the Bureau of Mines or any other recognized authority that impartially reflects reasonable market demand.
(4) Sworn or unsworn statements of interested parties and any other evidence which the Commission may deem relevant to the determination of reasonable market demand.
(e) For purposes of periodic market demand hearings, the Manager of Production and Proration for the Conservation Division shall prepare exhibits summarizing the nominations from the various interested parties specified in (d) in this Section. Said exhibits shall be available for public inspection not less than five days before the hearing. At the time of hearing, if no one announces any objection to the introduction of said exhibits, then the exhibits shall be admitted into evidence without need for sponsoring testimony.
(f) After the Commission has determined the amount of oil or gas to be produced from all oil and/or gas pools during the following proration period, the amount so determined will be allocated ratably and without discrimination among the various pools within the State.

PART 9. PURCHASERS AND TRANSPORTERS

165:10-1-45. Purchasers and transporters [RESERVED]

165:10-1-46. Reports of purchasers and/or transporters

Purchasers and/or transporters of oil, waste oil, or waste oil residue, including truckers, shall file reports with the Commission as follows:

(1) On or before the last day of the succeeding month, transporters shall file a report showing monthly takings by barrels from leases in all pools in the State, other than wells or leases as specified in (2), (3), (4), and (5) of this Section; a copy of the Gross Production Tax Report made to the Oklahoma Tax Commission will satisfy this requirement.

(2) A report on computer generated Form 1005 showing monthly takings by barrels from leases or wells with capacities greater than the maximum allowable determined by the appropriate rule governing the classification of the oil pool or order of the Commission. The report shall be filed on or before the last day of the succeeding month.

(3) Upon request, storage and nomination information shall be filed on Form 1034.

(4) All truck transporters hauling crude oil shall file a report showing the amount of all crude oil taken by them during the preceding proration period, and showing the source and the disposition of the crude oil, waste oil, or waste oil residue. The report shall be filed on or before the last day of the succeeding month.

(5) All truck transporters hauling crude shall provide their drivers with copies of standard run tickets which must be in the possession of the drivers at all times and which run tickets shall show the source and the disposition of crude oil, including but not limited to waste oil or waste oil residue.

165:10-1-47. Gas volume reports to Conservation Division

(a) On or before the last day of the succeeding month, the person responsible for operating the required meter under 165:10-17-5 for each well classified as an unallocated gas well for allowable purposes shall report to the Conservation Division on Form 1004 the amount of gas in MCF which passed through the meter on a monthly basis.

(b) If a well classified as a gas well for allowable purposes is subject to special pool rules other than the Guymon-Hugoton or South Guymon Fields, the Conservation Division shall mail Form 1005 (Monthly Allocated Schedule) to the operator of record for each such well(s) on or before the 15th day of each month. The operator of record shall, in turn, complete said form by listing the gas volume sold on a monthly basis in MCF by well and return a copy to the Conservation Division on or before the last day of the month succeeding the sales.

(c) If a well classified as a gas well for allowable purposes is subject to the special pool rules for the Guymon-Hugoton or South Guymon Fields, the Conservation Division shall mail Form 1005 (Monthly Allocated Schedule) to the operator of record for each such well(s) on or before the tenth day of each month. The operator of record shall, in turn, complete said form by listing the gas volume sold, including gas bought by the landowner, on a monthly basis in MCF by well and return a copy to the Conservation Division on or before the 15th day of the month succeeding the sales.

(d) If there is a split connection at the well site, then the operator of record measuring gas volumes shall be responsible for reporting the total volume sold for each well.

(e) If a well classified as a gas well for allowable purposes is subject to special pool rules (including the Guymon-Hugoton Field), the Conservation Division shall mail Form 1040 to each operator on or before the tenth day of

the second succeeding month following the custody transfer indicating the reported volume of gas taken from each well.
(f) If a well classified as a gas well for allowable purposes is subject to multiple gas purchase contracts or interest owners taking their gas in kind, the producing owner shall report and account to the well operator all volumes sold and the identity of all purchasers on or before the last day of the following month after sale of such gas. The operator(s) of the required meter(s) under 165:10-17-5 shall report and account to the well operator all volumes of gas measured by such meter(s) on or before the last day of the following month after measurement. Failure to comply with this subsection will result in such gas production being ordered shut-in.
(g) Failure of an operator to timely file sales volumes on Form 1005 shall result in a zero allowable being assigned to the operator's wells for the month in which the sales volumes would have been used in calculating the field allowable. Allocation factors for a pool shall not be recalculated as a result of the filing of a late Form 1005.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95]

165:10-1-48. Common purchaser and carrier rules
(a) 52 O.S., 1961, Sections 54, 55, 56, and 240 are hereby adopted as common purchaser and common carrier rules as fully as if set out verbatim herein.
(b) No person shall purchase, take, or transport any oil or gas in excess of the allowable fixed by the Commission, or, when notified by the Conservation Division, such oil or gas being produced in violation of any rule, regulation, or order of the Commission; provided, this Section shall not require splitting a tank.

165:10-1-49. Filing of nominations
All operators of natural gas wells in special allocated gas pools where well allowable calculations according to special allocated field rules are in effect shall file their pool nominations on Form 1034-G not later than one week prior to the date of the market demand hearing.
(1) Nominations shall be restricted to the volume not to exceed the wellhead absolute open flow (WHAOF) times calendar days for each well in a pool. For wells in pools where the WHAOF is not utilized, the equivalent well deliverability or calculated rate of flow applicable to that particular pool may be used in lieu of the WHAOF. For wells exempt from testing, nominations shall be restricted to a volume not to exceed the well's minimum, double minimum, or special allowable time calendar days.
(2) Operators shall attach to Form 1034-G a listing of each of their special allocated wells by pool, OTC Lease Number, API Number, well name and number, and location as recorded on Form 1040, plus the applicable WHAOF, deliverability, or rate of flow value as determined by the appropriate well test for that time period. Wells exempt from testing shall be indicated as test-exempt on the list.
(3) Failure of an operator to properly file nominations on Form 1034-G shall result in a zero allowable being assigned to the operator's wells for the month in which the nominations would have been used in calculating the field allowable. Allocation factors for a pool shall not be recalculated as a result of the filing of a late Form 1034-G.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

SUBCHAPTER 3. DRILLING, DEVELOPING, AND PRODUCING

PART 1. DRILLING

PART 3. COMPLETIONS

PART 5. OPERATIONS

PART 7. PRODUCTION

PART 1. DRILLING

165:10-3-1. Required approval of notice of intent to drill, deepen, re-enter, or recomplete; Permit to Drill

(a) **Permit to Drill.**

(1) Except as provided in (1) of this Section, on emergency authorization to commence, the operator shall obtain for the well a Permit to Drill approved by the Conservation Division before:

(A) Spudding a well for the exploration for and production of oil or gas.

(B) Spudding a well for use as an injection, disposal, or service well.

(C) Re-entry into a plugged well.

(D) Recompletion of a well.

(E) Deepening an existing well.

(2) A Permit to Drill shall be valid only for each common source of supply listed on the permit.

(3) Any operator who drills, deepens, reenters or recompletes a well without a permit to drill may be fined up to $1,000.00.

(4) An operator requesting a Permit to Drill for a horizontal well shall submit a plat utilizing Commission records showing the location and total

depth of each abandoned, plugged, producing or drilling well, and dryhole within one quarter (1/4) mile of the completion interval of the proposed horizontal well.

(b) **Amended or additional Form 1000 requirements.**

(1) **When required.** If the Conservation Division has issued a Permit to Drill for a well, the operator of the well shall submit an amended Form 1000 for the well and obtain an amended Permit to Drill before:

(A) Completing the well in a common source of supply which is not listed on the current unexpired Permit to Drill for the well.

(B) Recompleting the well in a common source of supply which is not listed on the current unexpired Permit to Drill for the well.

(C) Installing less surface casing than the amount approved on the unexpired Permit to Drill for the well.

(D) Deviating from an alternative casing and cementing procedure which the Conservation Division approved on the unexpired Permit to Drill for the well.

(E) Completing a well in a common source of supply at a subsurface location which does not correspond with the surface location on the most recently issued Permit to Drill for the well.

(2) **Effect of amended or additional Permit to Drill on prior Permit to Drill.** Each approved, amended, or additional Permit to Drill for a well cancels any previously issued Permit to Drill for the well.

(c) **Expired or revoked Permit to Drill.** If a Permit to Drill for a well expires or is revoked, the operator shall be subject to the requirements of (a) of this Section.

(d) **Casing and cementing requirements.** Each Permit to Drill shall list the minimum amount of surface casing to be used or an approved alternative casing and cementing program under 165:10-3-4.

(e) **Spud report and well spacing requirements.** In addition to complying with the requirement of obtaining a Permit to Drill, the operator shall comply with the following:

(1) The spud report requirement of 165:10-3-2.

(2) Any well spacing requirements applicable by order or rule of the Commission. Well spacing requirements do not apply to injection or disposal wells.

(f) **Disposal of drilling fluids.**

(1) The operator shall indicate on Form 1000 the proposed method(s) for disposal of drilling fluids. These methods shall include, but not be limited to:

(A) Evaporation/dewatering and leveling of the reserve pit.

(B) Soil farming.

(C) Recycling.

(D) Commercial off-site earthen pit disposal.

(E) Annular injection.

(F) Hauling to a facility or location other than a commercial earthen pit.

(2) If the method in (1)(F) in this subsection is used, the operator shall provide the location to which the drilling fluids are to be hauled.

(3) Issuance of the Permit to Drill shall not be construed as constituting approval of the disposal method(s) indicated. An operator who desires to dispose of drilling fluids through either evaporation/dewatering and leveling of the reserve pit, soil farming, commercial earthen pit disposal, or annular injection must comply with 165:10-7-16, 165:10-7-19 or 165:10-9-2, 165:10-9-1, or 165:10-5-13 respectively.

(4) If the proposed method for drilling fluid disposal is changed, the operator shall notify the appropriate Conservation Division District Office, either by telephone, facsimile or electronic mail, within twenty-four (24) hours after the change. An amended Form 1000 for the well shall not be required for a change in disposal method.

(g) **Notice to surface owners.**

(1) The operator shall include on each Form 1000 submitted to the Conservation Division, the name and address of each surface owner of record for the wellsite.

(2) For each Permit to Drill other than a Permit to Drill for a recompletion, the Conservation Division shall mail by regular U.S. mail a copy of the Permit to Drill to each surface owner listed on the Form 1000.

(h) **Disapproval for noncompliance with Commission order.** If an operator is not in compliance with an enforceable order of the Commission, the Conservation Division shall not issue any Permit to Drill for the operator, until the operator complies with the order.

(i) **Erroneous approval.** Erroneous issuance of a Permit to Drill shall not excuse noncompliance with any order or rule of the Commission.

(j) **Expiration.**

(1) **Eighteen-month period.** Except as provided in (2) of this subsection for expiration after submission of a completion report, a permit to drill shall expire eighteen months from the date of issuance, unless drilling operations are commenced and thereafter continued with due diligence to completion.

(2) **Six-month extension.** A six month extension may be granted without fee providing the Conservation Division staff determines that no material change of condition has occurred, if written request for such extension is received from the operator prior to the expiration of the original permit. Only one extension may be granted.

(3) **If Form 1002A is filed.** If the operator of the well submits to the Conservation Division a Completion Report (Form 1002A) for the well, the Permit to Drill for the well shall expire on the date the Completion Report is approved by the Conservation Division.

(k) **Posting of Permit to Drill at the wellsite.** During any activity subject to this Section, the operator shall maintain at the wellsite an original or legible copy of the Permit to Drill for inspection by Commission personnel.

(l) **Emergency authorization without approval of a Permit to Drill.** In an emergency, the Manager of the Technical Services Department of the Conservation Division may temporarily authorize commencement of activities without a Permit to Drill for a period up to five business days.

(m) **Limits of authority.** A Permit to Drill does not grant the operator authority to produce, inject or dispose without the required permits or allowable assignment.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99; Amended at 24 OK Reg 1790 (RM 200700004), eff 7-1-2007; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-3-2. Notification of spudding of new well

(a) Except as provided in (c) of this Section, the operator of a new well shall file with the Conservation Division a Notice of Spudding of New Well on Form 1001A within 14 days after spudding of the well.

(b) For the purposes of (a) of this Section, spudding of a new well refers to:

(1) The first boring of the portion of the hole intended to penetrate the base of treatable water or a common source of supply, whichever is shallower, in the drilling of a well for the production of oil and gas or for use as an injection, disposal or service well.

(2) Reentry into a previously plugged well for purposes of producing oil and gas or for use as an injection, disposal or service well.

(c) Filing of a Notice of Spudding of a New Well on Form 1001A shall not apply to:

(1) Any workover operation to deepen, plug-back, or recomplete.

(2) An unplugged hole spudded before January 9, 1986.

(3) Recompletion attempts in an unplugged hole for which a Notice of Spudding of New Well has been filed.

(d) In addition to the notification of spudding a new well as required in (b) of this Section, the operator shall notify the district office no less than 24 hours before the first boring of the hole for setting conductor pipe used for the sole purpose of near surface stabilization of the borehole when such operations are not continuous with spudding operations as defined in (b) of this Section. The notification required by this subsection may be provided in person, by phone, or in writing, and any written notification may be submitted by mail, fax, e-mail or other electronic means.

[**SOURCE:** Amended at 24 OK Reg 1790 (RM 200700004), eff 7-1-2007; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-3-3. Well casing strings

(a) Owners, operators, and drilling contractors shall comply with 165:10-3-4 and 165:10-5-2.

(b) In the event a rupture, break, or opening occurs in any casing string, the owner or operator shall take immediate action to repair it and shall report the occurrence either by telephone or by electronic mail to the appropriate Conservation Division District Office or the Manager of Pollution Abatement within twenty-four (24) hours of discovery. The owner or operator shall also submit a written report to the appropriate Conservation Division District Office within ten (10) business days containing the following information:

(1) Name of party reporting, firm name, mailing address, telephone number and electronic mail address.

(2) Well name and legal description.

(3) Name of operator.

(4) Date of discovery of rupture, break or opening in the casing string.

(5) Description of circumstances associated with the discovery of a rupture, break or opening in the casing string.

(6) Actions taken or proposed to be taken to repair the rupture, break or opening in the casing string.

(c) Any owner or operator who fails to timely report the discovery of a rupture, break, or opening in any casing string may be fined up to $5,000.00, and the well shall be shut down until it is repaired or plugged.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001)]

165:10-3-4. Casing, cementing, wellhead equipment, and cementing reports

(a) **Scope.**

(1) This Section governs the following:

(A) Surface casing and cementing requirements.

(B) Alternate casing and cementing procedure used instead of adequate surface casing and cement.

(C) Minimum cementing and testing requirements for intermediate and production casing.

(D) Minimum valve and blowout preventer requirements.

(E) Cementing reports.

(2) This Section shall apply to the following:

(A) Wells drilled or reentered for the production of oil, gas or brine.

(B) Wells drilled or reentered for disposal of oilfield wastes.

(C) Wells drilled for enhanced recovery injection.

(D) Wells drilled in subsurface gas storage units created by order of the Commission.

(E) Other oilfield related service wells.

(b) **Effect on area rules.**

(1) If any area rules promulgated by order of the Commission require less casing and cement than required by this Section, then this Section shall supersede the area rules.

(2) If an applicable area rule promulgated by order of the Commission has more stringent casing and cementing requirements than what are required by this Section, the Conservation Division shall enforce the area rules.

(c) **Surface casing and cementing requirements for wells listed in (a)(2) of this Section:**

(1) **Minimum surface casing requirements.** Unless an alternate casing program is authorized by the Conservation Division or by an order of the Commission, suitable and sufficient surface casing shall be run and cemented from bottom to top with a minimum setting depth which is the greater of:

(A) Ninety feet below the surface, or

(B) Fifty feet below the base of treatable water.

(2) **Penalty for noncompliance.** An operator setting less than the required amount of surface casing or failing to remediate uncirculated cement before resuming operations may be fined up to $5,000.00.

(3) **Exceptions to (c)(1).** Operators having wells producing hydrocarbons which were in compliance with the surface casing requirements at the time of completion shall not be required to comply with (1) of this subsection.

(4) **Well to be used for annular injection under 165:10-5-13.** If the operator intends to dispose of drilling or stimulation fluids by annular injection, then the operator shall comply with 165:10-5-13 which requires a surface casing string to be set not less than 200 feet below the base of treatable water, unless a Commission order provides otherwise.

(5) **Depth limitation on setting surface casing.** The well operator shall run and cement the surface casing string required by this subsection before drilling the well more than 250 feet below the base of treatable water, unless otherwise approved on the Permit to Drill.

(6) **Penalties.** Operators failing to obtain permission to drill a well more than 250 feet below the treatable water, or to obtain permission for an alternate casing and cementing procedure may be fined up to $2,500.00.

(7) **Cementing procedures.**

(A) **Approved methods.** Except as provided in (B) of this paragraph for bradenhead cementing, cement shall be run by either the tubing and pump method, the pump and plug method, or the displacement method.

(B) **Bradenhead cementing prohibited.** Bradenhead cementing is prohibited without written permission from the appropriate Conservation Division District Office.

(C) **Restrictions on stage cementing.**

(i) **Above 200 feet.** Running cement through small tubulars is permitted above 200 feet in depth without special permission.

(ii) **Below 200 feet.** Below 200 feet in depth, the operator shall obtain permission from the appropriate Conservation Division District Office before using small tubulars to run cement.

(D) **Steel casing required.** For purposes of the surface casing requirements of this Section, surface casing shall be oil field grade steel casing.

(E) **Witnessing of setting of surface casing.** The operator shall give at least 24 hours notice by telephone, facsimile or electronic mail to the appropriate Conservation Division District Office or Field Inspector as to the time when surface casing will be run.

(F) **Minimum cement setup time.** The cement behind the surface casing shall set at least eight hours before further drilling.

(G) **Down-hole testing of surface casing and cement.** Before drilling the shoe of the surface casing, the operator shall test the surface casing using the procedure prescribed by (g) of this Section.

(H) **Failure to circulate cement or fall back of cement behind surface casing.**

(i) **Verifying the top of cement.** If no conductor string is set and the cement did not circulate to the surface or falls back more than five feet, the operator shall determine the top of the cement using a method approved by the District Manager or Field Inspector Supervisor.

(ii) **Top of cement less than 200 feet from the surface.** If the top of the cement is found less than 200 feet from the surface, the operator may circulate cement to surface using small tubulars.

(iii) **Top of cement greater than 200 feet from the surface.** If a conductor string has been set and the cement has been found to be ten feet or more above the base of the conductor string, no corrective action is required. If no conductor string has been set and the top of the cement is greater than 200 feet from the surface, the operator shall perform a corrective cementing operation by circulating cement to the surface from a point 50 feet below the base of the treatable water or from the determined top of the cement, whichever is shallower. The District Manager or Field Inspector Supervisor may grant permission to circulate cement through small tubulars.

(I) **Insufficient surface casing or mechanical failure.** Within 24 hours after discovery of a problem with the surface casing or cement, the operator shall notify the appropriate Conservation Division District Office by telephone, facsimile or electronic mail of:

(i) Any mechanical failure of the surface casing or cement.

(ii) Discovery of a treatable water formation below the shoe of the surface casing.

(J) **Penalty.** An operator, failing to report a rupture, break, or opening in the surface casing, may be fined up to $1,000.00 and the well shut down.

(K) **Notice.** The District Manager or Field Inspector shall be given at least 24 hours notice by telephone, facsimile or electronic mail prior to any cementing operation in order that they may have the opportunity to witness.

(d) **Alternate casing and cementing procedures.**

(1) **Requirement of approval on the Permit to Drill.** Use of an alternative casing and cementing procedure instead of surface casing and cement required by (c) of this Section is prohibited without authorization on the Permit to Drill for the well.

(2) **Disapproval.** The Manager of Technical Department may not issue a permit for an alternate casing string and cementing procedure if one or more of the following conditions exist:

(A) The well will penetrate a known lost circulation zone.

(B) The treatable water bearing formation(s) will be endangered.

(C) The projected depth of the well is less than 100 feet from the top of any authorized secondary project or gas storage facility.

(3) **Applicability of other casing and cementing standards.** Alternate casing and cementing procedures under this subsection are subject to the provisions of (c)(7) of this Section.

(4) **Alternate casing and cementing procedure.**

(A) An operator having permission to run an alternate casing string may, for protection of the treatable water, drill the well to casing point and circulate cement to the surface, or circulate cement from a depth of 100 feet below the base of treatable water to the surface after following the procedures set out in (f) of this Section.

(B) Oil based drilling mud shall be prohibited.

(C) If a well is completed using an alternate casing and cementing procedure, a bond log covering the interval from 100 feet below the base of the treatable water to the surface shall be required. The District Manager may waive this requirement. A completion attempt, in cases where the protection of treatable water is questionable, is strictly prohibited.

(D) Unless extended by the District Manager, the operator shall have 72 hours after drilling and testing is completed to run production casing or

plug the well. A minimum of 24 hours prior notice by telephone, facsimile or electronic mail must be given to the appropriate Conservation Division District Office prior to cementing operations so that a Field Inspector may have the opportunity to witness the cementing or plugging procedures. If the well is plugged and abandoned, procedures set out in (e) of this Section shall be followed.

(E) In the event that casing is run and cement does not circulate to the surface, or falls back, the operator shall determine the top of the cement using a method approved by the District Manager.

(5) **Remedial actions.**

(A) If the top of the cement is less than 200 feet from the surface, the operator may circulate cement from that point to the surface using small tubulars or by perforating the casing at that point and circulating cement to the surface.

(B) If the top of the cement is greater in depth than 200 feet, the operator shall perforate the casing at the top of the cement and circulate cement to the surface, or with the written permission of the District Manager or Field Inspector Supervisor, use small tubulars.

(C) In the event that a conductor string had been set and the top of the cement is at least ten feet above the base of the conductor casing no remedial action is needed.

(D) Unless waived by the appropriate Conservation Division District Office, all corrective cementing operations shall be approved and witnessed by the Field Inspector.

(E) In wells where corrective actions were needed for casing or cementing problems, a completion attempt shall not be made without approval by the District Manager.

(e) **Permanent well marker.** In the event that the well is a dry hole and no casing has been run, then during the plugging of the well the operator shall run and cement from bottom to top at least one joint of casing at the surface not less than 25 feet in length for use as a permanent well marker. The casing used as a well marker shall be oil field grade steel casing with an outside diameter of at least seven inches. The top of the marker shall be three feet below the surface and be capped with a steel plate inscribed or embedded with the well number and date of plugging on the steel plate. An operator failing to run and cement the well marker as required may be fined up to $1,000.00 and shall, under the supervision of the Commission, replug the well.

(f) **Minimum cement for additional casing strings.** If additional casing other than surface casing is run, except for temporary purposes, it shall be run, set, and cemented with a calculated volume of cement sufficient to fill the annular space behind the casing string from the base of the casing string to a minimum height which is the greater of five percent of the depth to which the casing string is set, or a height of 200 feet. Any well approved for horizontal completion shall be cemented with a calculated volume of cement sufficient to fill the annular space behind the production casing string to isolate the producing formation. The Conservation Division may grant a variance to this requirement for a horizontal well upon request.

(g) **Pressure testing of casing strings.**

(1) Before drilling the cement plug in a casing string, the operator shall pressure test the installed casing for 30 minutes at a minimum pressure which is the lesser of the surface gauge pressure equal in pounds per square inch to 0.2 of the length of the casing in feet or 1500 psig.

(2) During the 30 minute test, if the surface pressure drops ten percent or more, the operator shall:

(A) Repair and retest the casing until the requirements of this subsection are met; or

(B) Plug the well according to the rules of this Chapter.

(h) **Minimum wellhead equipment for drilling wells.** All reasonable and prudent precautions shall be taken for keeping the well under control during drilling operations, including but not limited to the use of blowout preventers or other

similar equipment with appropriate pressure fittings attached to properly cemented casing strings and the maintenance of mud-laden fluid of sufficient weight to provide proper well control. A blowout preventer or other equipment necessary to maintain control of the well shall be installed prior to drilling out of the surface casing. Blowout preventers and associated equipment shall be maintained in good working order. Blowout preventers shall be pressure tested at regular intervals, not to exceed twenty-one days, to ensure proper operation. A function test shall be conducted on a routine basis during drilling operations to ensure that annular preventers and rams will operate properly. Alternate testing procedures may be approved by the District Manager. The rig personnel shall be trained in the use of blowout prevention equipment and well control procedures on the rig.

(i) **Cementing reports.**

(1) The operator of the well shall submit, attached to Form 1002A Completion Report, a Form 1002C Cementing Report describing all cementing operations on surface, intermediate, and production casing strings, including multistage cementing jobs.

(2) If additional cementing operations occur after submission of the Cementing Report, the operator shall submit an amended Form 1002C for the well.

(j) **Surface casing requirements for re-entry wells.** For a re-entry as defined by 165:10-1-2, casing and cementing requirements at the time of re-entry shall apply.

(k) **Surface casing requirement for recompletions.** For a recompletion as defined by 165:10-1-2, casing and cementing requirements applicable to wells commenced on the latter of the spud date or re-entry date for the well shall apply.

(l) **Casing and cementing requirements for wells converted for injection or disposal.** If a well is converted for use as an injection or disposal well, it shall be subject to the casing and cementing requirements of this Section effective at the time of conversion of the well.

(m) **Casing and cementing requirements for wells penetrating unitized common sources of supply.** Each newly drilled or re-entered well which penetrates a common source of supply in which enhanced recovery operations are being conducted shall be properly cased and cemented from not less than 100 feet below to not less than 100 feet above each unitized common source of supply to prevent migration of formation fluids and contain formation pressure. In the event the well is to be plugged without being cased, the well shall be properly cemented over the aforementioned interval(s) during plugging procedures.

(n) **Insufficient surface casing and cement.** When it has been determined that a treatable water-bearing formation has not been properly cased and cemented, the operator shall take such measures designated by the Director of Conservation or ordered by the Commission to protect any treatable water-bearing formation.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)

165:10-3-5. Underground storage

(a) **Scope.** This Section shall apply to all operations pertaining to the drilling, completion, recompletion, or remedial work on wells located within the boundaries of an underground storage facility as defined in (b)(4) of this Section.

(b) **Definitions.**

(1) "Underground storage" shall mean storage of natural gas in a subsurface stratum or formation of the earth.

(2) "Natural gas" shall mean gas either while in its natural state or after the same has been processed by removal therefrom of component parts not essential to its use for lights and fuel.
(3) "Storage operator" shall mean any person, firm, or corporation which operates an underground storage facility.
(4) "Underground storage facility" shall mean any subsurface stratum or formation of the earth used for underground storage. Provided that, in the case of a natural gas bearing subsurface stratum or formation, the commercially producible native gas shall have been substantially depleted and the gas therein shall not be used primarily for the secondary recovery of oil in paying quantities from the subsurface stratum or formation.
(5) "Well" means a well drilled or bored or to be drilled or bored within the boundaries of an underground storage facility.
(6) "Well operator" shall be the person, firm, or corporation that is the operator of a well.
(7) "Major remedial work" shall mean any workover operations requiring wire line or pump truck services.
(8) "Good quality cement" means that cement that would obtain a compressive strength to prevent oil, gas, or water migration within an eight (8) hour period.

(c) **Operational procedures.**
(1) Before spudding a well within the boundaries of a gas underground storage facility, the well operator shall mail a copy of the Permit to Drill to the storage operator at the address listed at the Commission. The storage operator will inform the well operator of the estimated depth, thickness, and pressure of the underground storage facility at that location. Failure of the storage operator to provide the data to the well operator shall not be a cause to delay drilling, but the well operator is required to notify the storage operator, by phone a minimum of 24 hours prior to commencing drilling operations at a 24 hour telephone number furnished to the Commission by the storage operator.
(2) A well operator shall comply with the provisions of 165:10-3-4(c). Alternate casing programs shall not be permitted.
(3) Drilling rigs shall be equipped with a blowout preventer. The preventer shall be installed and tested at least 500 psig above the anticipated underground storage facility pressure before drilling below the base of the surface casing.
(4) The storage operator shall receive drilling reports daily and shall be notified at a 24 hour telephone number furnished to the Commission by the storage operator in ample time to witness any tests or logging operations from the surface to 500 feet below the base of the underground storage facility. Any abnormal conditions occurring during the drilling operation, such as abnormal pressures and/or lost circulation, shall be reported immediately to the storage operator.
(5) The well operator shall drill the well in such a manner as to prevent invasion of drilling fluids into, or the escape of natural gas from, the underground storage facility. The well operator shall be required to mud up at least 100 feet above the anticipated depth of the underground storage facility.
(6) If run, a copy of either an open hole porosity or resistivity well log run from the base of surface casing to total depth shall be promptly forwarded to the storage operator. At the option of the well operator, the logs submitted to the storage operator may be terminated 500 feet below the base of the underground storage facility. The storage operator shall be given prior notice of logging operations of the underground storage facility interval and has the option of witnessing the open hole logging operation.
(7) In the event that the well is noncommercial and is to be plugged and abandoned, the well operator shall place a cement plug using a good quality cement, covering from not less than 100 feet below the base to not less than 100 feet above the top of the underground storage facility. The storage

operator shall be given prior notice so as to have the option of witnessing the plugging operation. The field inspector may invoke the provisions of 165:10-11-6 (l), (m), and (n).

(8) In the event that casing is run, the well operator will cause the underground storage facility interval to be covered with steel casing and be cemented from not less than 100 feet below the base to not less than 100 feet above the top of the underground storage facility using a good quality cement. The Commission field inspector for the area and storage operator shall be given prior notice so as to have the option of witnessing the operation.

(9) The well operator shall be required to run a cement bond log through the underground storage facility formation before any completion attempts are made. The storage operator shall be given prior notice so that he will have the option of witnessing the logging operation and be furnished with a copy of the bond log from the top of cement to total depth or, at the option of the well operator, to 500 feet below the base of the underground storage facility. If the integrity of the bond log is questioned by the storage operator, the storage operator may, at its sole risk and expense, run additional logs. No completion work shall be permitted until the fact has been established, between the parties concerned, and the district manager of the Commission, that the integrity of the cement is sound and that the underground storage facility is isolated from the remainder of the bore hole. The remedial work, if needed to protect the storage reservoir, shall be at the risk and expense of the well operator.

(10) The storage operator shall be notified in ample time to witness completion, recompletion, or major remedial work operations. The well site shall be made accessible at all times to the storage operator and all information pertaining to the completion shall be forwarded daily to the storage operator. If the completion, recompletion, or major remedial operations attempt is to be made in any formation within 500 feet in depth to the underground storage facility, the proposed plan of completion shall be forwarded to the storage operator ten days prior to commencement of operations. The storage operator shall have five days after receipt of the proposed plan to forward any objection to the well operator. Completion operations, recompletion, or major remedial operations shall not be permitted until the matter is resolved.

(11) At any time that the storage operator shall reasonably believe that damage may be occurring to the underground storage facility or that gas may be escaping into any other formations or otherwise believe that a well may be compromising the integrity of the underground storage facility, the storage operator may request that the operator of the well conduct specific tests solely at the storage operator's risk and expense. If an agreement cannot be obtained between the parties concerned, the storage operator may bring the matter before the Corporation Commission for determination by application, notice, and hearing following the procedure set out in OAC 165:5-7.

(12) If tests establish that damage is occurring and/or that natural gas is escaping by the continued operation of the well, the well shall be shut down immediately and the remedial operation to rectify the condition shall be commenced within ten days, at the sole risk and expense of the well operator.

(13) All information furnished to the storage operator shall be kept confidential until released in writing by the well operator.

PART 3. COMPLETIONS

165:10-3-10. Well completion operations

(a) **Hydraulic fracturing and acidizing.** In the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface or subsurface fresh water. Unless an operator confers with and obtains

the approval of the Conservation Division, the use of diesel fuel as the base fluid for hydraulic fracturing operations is prohibited. Approval of the Conservation Division shall be reflected in writing. Within 5 days of obtaining written authorization, the operator is required to send the authorization by facsimile, electronic mail or regular mail to the following:

(1) The owner of the surface location where the proposed well is to be drilled; and

(2) Each operator of a producing spacing unit or well within 1/2 mile of the perforated interval of the proposed well.

(b) **Notice of hydraulic fracturing operations.**

(1) Notice shall be given by facsimile, electronic mail or regular mail at least 5 business days prior to the commencement of hydraulic fracturing operations on a horizontal well to operators of producing wells within 1/2 mile of the completion interval of the subject well and which are completed in the same common source of supply as the horizontal well.

(2) Notice shall be given by telephone, facsimile or electronic mail to the appropriate Conservation Division District Office or Field Inspector at least 48 hours prior to commencement of hydraulic fracturing operations on a well.

(3) Separate stages of a planned multi-stage hydraulic fracturing operation shall not constitute separate hydraulic fracturing operations for notification purposes.

(4) If an operator has evidence that hydraulic fracturing operations have impacted its well(s), the operator may report the occurrence by electronic mail to the appropriate Conservation Division District Office within 24 hours of discovery. The operator shall use Form 4000WIP to report the occurrence.

(c) **Chemical disclosure.** Within 60 days after the conclusion of hydraulic fracturing operations on an oil, gas, injection, disposal, or service well that is hydraulically fractured, the operator must submit information on the chemicals used in the hydraulic fracturing operation to the FracFocus Chemical Disclosure Registry or, alternatively, submit the information directly to the Commission. If the chemical disclosure information is submitted directly to the Commission under this subsection, the Commission will post such information on the FracFocus Chemical Disclosure Registry.

(1) The submission required by this subsection must include the following information:

(A) the name of the operator;

(B) the API number of the well;

(C) the longitude and latitude of the surface location of the well;

(D) the dates on which the hydraulic fracturing operation began and ended;

(E) the total volume of base fluid used in the hydraulic fracturing operation;

(F) the type of base fluid used;

(G) the trade name, supplier, and general purpose of each chemical additive or other substance intentionally added to the base fluid; and

(H) for each ingredient in any chemical additive or other substance intentionally added to the base fluid, the identity, Chemical Abstract Service (CAS) number, and maximum concentration. The maximum concentration for any ingredient must be presented as the percent by mass in the hydraulic fracturing fluid as a whole, and is not required to be presented as the percent by mass in any particular additive.

(2) For purposes of this subsection, the phrase "chemical additive or other substance intentionally added to the base fluid" refers to a substance knowingly and purposefully added to the base fluid and does not include trace amounts of impurities, incidental products of chemical reactions or processes, or constituents of natural materials.

(3) The operator is not responsible for inaccurate information provided to the operator by a vendor or service provider, but the operator is responsible for ensuring such information is corrected when any inaccuracy is discovered.

(4) If certain chemical information, such as the chemical identity, CAS number, and/or maximum concentration of an ingredient, is claimed in good faith to be entitled to protection as a trade secret under the Uniform Trade Secrets Act, 78 O.S. §§85-94, the submission to the FracFocus Chemical Disclosure Registry may note the proprietary nature of that chemical information instead of disclosing the protected information to the registry. The submission must include the name of the supplier, service company, operator, or other person asserting the claim that the chemical information is entitled to protection as a trade secret and provide the chemical family name or similar descriptor for the chemical if the chemical identity and CAS number are not disclosed. The Commission or the Director of the Oil and Gas Conservation Division may require the claimant to file with the Commission a written explanation in support of the claim.

(5) Nothing in this subsection restricts the Commission's ability to obtain chemical information under the provisions of OAC 165:10-1-6 or other applicable Commission rules.

(6) This subsection applies to:

(A) horizontal wells that are hydraulically fractured on or after January 1, 2013; and

(B) other wells that are hydraulically fractured on or after January 1, 2014.

(d) **Rule reference guide.** References to Commission rules regarding management of hydraulic fracturing operations are as follows:

(1) Duties and authority of the Conservation Division (OAC 165:10-1-6).

(2) Required approval of notice of intent to drill, deepen, re-enter or recomplete; Permit to Drill (OAC 165:10-3-1).

(3) Surface and production casing (OAC 165:10-3-3).

(4) Casing, cementing, wellhead equipment and cementing reports (OAC 165:10-3-4).

(5) Swabbing and bailing (OAC 165:10-3-11).

(6) Leakage prevention in tanks; protection of migratory birds (OAC 165:10-3-13).

(7) Well site and surface facilities (OAC 165:10-3-17).

(8) Completion reports (OAC 165:10-3-25).

(9) Administration and enforcement of rules (OAC 165:10-7-2).

(10) Cooperation with other agencies (OAC 165:10-7-3).

(11) Water quality standards (OAC 165:10-7-4).

(12) Prohibition of pollution (OAC 165:10-7-5).

(13) Protection of public water supplies (OAC 165:10-7-6).

(14) Informal complaints, citations, red tags and shut down of operations (OAC 165:10-7-7).

(15) Scheduled monetary fines (OAC 165:10-7-9).

(16) Use of noncommercial pits (OAC 165:10-7-16).

(17) Surface discharge of fluids (OAC 165:10-7-17).

(18) Discharge to surface waters (OAC 165:10-7-18).

(19) One-time land application of water-based fluids from earthen pits and tanks (OAC 165:10-7-19).

(20) Noncommercial disposal or enhanced recovery well pits used for temporary storage of saltwater (OAC 165:10-7-20).

(21) Waste management practices reference chart (OAC 165:10-7-24).

(22) One-time land application of contaminated soils and petroleum hydrocarbon based drill cuttings (OAC 165:10-7-26).

(23) Application of fresh water drill cuttings by County Commissioners (OAC 165:10-7-28).

(24) Application of freshwater drill cuttings by oil and gas operators (OAC 165:10-7-29).

(25) Application to reclaim and/or recycle produced water for surface activities related to drilling, completion, workover, and production operations from oil and gas wells (OAC 165:10-7-32).

(26) Use of commercial pits (OAC 165:10-9-1).

(27) Commercial soil farming (OAC 165:10-9-2).
(28) Commercial recycling facilities (OAC 165:10-9-4).
(29) Duty to plug and abandon (OAC 165:10-11-3).
(30) Notification and witnessing of plugging (OAC 165:10-11-4).
(31) Plugging and plugging back procedures (OAC 165:10-11-6).
(32) Plugging record (OAC 165:10-11-7).
(33) Review of environmental permit applications (OAC 165:5-1-15 through OAC 165:5-1-19)
(34) Response to citizen environmental complaints (OAC 165:5-1-25 through OAC 165: 5-1-30).
(35) Contempt (OAC 165:5-19-1 through OAC 165:5-19-2).

[**Source:** Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-3-11. Swabbing and bailing

In swabbing, bailing, or purging a well, all deleterious substances removed from the borehole shall be placed in adequate pits or tanks, and no such substances shall be permitted to pollute any surface and subsurface fresh water.

165:10-3-12. Leakage prevention in producing oil and gas wells

All wellhead connections, surface equipment, and tank batteries shall be maintained at all times so as to prevent leakage of oil, gas, saltwater, or other deleterious substances.

165:10-3-13. Water pollution prevention in tanks; protection of migratory birds

(a) Tanks for drilling mud or deleterious substances used in the drilling, completion, or recompletion of wells shall be constructed and maintained so as to prevent pollution of surface and subsurface fresh water.

(b) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil, all open top tanks containing oil on the surface be protected from access to birds. [See Advisory Notice 165:10-7-3(c)].

165:10-3-14. Waste of oil or gas

Except as provided in 165:10-3-15, waste of oil, condensate, or gas as defined in 165:10-1-2, is hereby prohibited.

165:10-3-15. Venting and flaring

(a) **Conditioning a producing well without a permit.** An operator may blow down a producing well without a permit for a period not to exceed 72 hours if:

(1) Blowing down the well is necessary for efficient operation of the well or unexpected circumstances are encountered;
(2) Blowing down the well will not damage any producing formation in the well; and
(3) The operator complies with the H_2S requirements of 165:10-3-16.

(b) **Gas volumes less than or equal to 50 mcf/d.** An operator may vent or flare up to 50 mcf/d without a permit if:

(1) It is not economically feasible to market the gas;
(2) A suitable stand, line, or stack is used to prevent a hazard to people, and such stand, line or stack has a properly installed and operating stack arrestor; and
(3) H_2S content of gas exceeds 100 ppm, then the gas must be flared.

(c) **Permit to vent or flare gas volumes in excess of 50 mcf/d.**

(1) The Conservation Division may administratively grant a permit to vent or flare on a daily basis gas volumes in excess of 50 mcf/d, if:

(A) The operator applies for the permit on Form 1022;
(B) The application lists the location of the well and the maximum daily volume of gas to be vented or flared;
(C) It is not economically feasible to market the gas; and
(D) A suitable stack, stand, or line will be used to prevent a hazard to people or property, and such stand, line or stack has a properly installed and operating stack arrestor.

(2) The operator shall file an amended application in the event that the amount of gas to be vented or flared exceeds the permitted volume.

(d) **Temporary permit exemption for gas vented or flared during initial flowback from a newly completed or recompleted well.** Gas vented or flared during initial flowback from a newly completed or recompleted well shall be exempt from the permit requirements of subsection (c) for a period not to exceed 14 days, commencing with the first date gas flow is in excess of 50 mcf/d, if:

(1) Combustible gas flow greater than 50 mcf/d is flared;
(2) Gas with H2S content in excess of 100 ppm is flared;
(3) The operator gives at least 48 hours notice by electronic mail or facsimile to the appropriate Conservation Division District Office or Field Inspector regarding the time when the venting or flaring of gas pursuant to this subsection will begin;
(4) It is not economically feasible to market the gas; and
(5) A suitable stack, stand, or line will be used to prevent a hazard to people or property, and such stand, line or stack has a properly installed and operating stack arrestor.

(e) **Gas flared after initial flowback from a newly completed or recompleted well.** Subsequent to the 14 day initial flowback period addressed in subsection (d), gas flared during flowback from a newly completed or recompleted well shall be exempt from the permit requirements in subsection (c) for an additional period not to exceed 30 days if:

(1) Gas volumes flared from the well are less than or equal to an average rate of 300 mcf/d over the 30 day period, and one or more of the following conditions applies:
(A) No appropriate takeaway structure exists;
(B) The well is an exploration well; or
(C) The quality of the gas to be flared is not pipeline acceptable.
(2) Gas with H2S content in excess of 100 ppm must be flared.
(3) A suitable stack, stand, or line must be used to prevent a hazard to people or property, and such stand, line or stack has a properly installed and operating stack arrestor.
(4) The well operator is required to maintain a daily log of gas volumes flared from the well during the 30 day period. The daily log must be preserved for 3 years subsequent to the conclusion of the 30 day period. The log shall be produced upon request by an authorized representative of the Commission.
(5) If gas volumes greater than 300 mcf/d are to be flared during flowback from a newly completed or recompleted well subsequent to the initial 14 day period addressed in subsection (d), then the operator is required to obtain a permit as provided in subsection (c).

(f) **Application for an order permitting venting or flaring.**

(1) If the Conservation Division denies a Form 1022 application for a well, the operator of a well may apply for an order permitting venting or flaring of gas.
(2) The application and notice shall be in accordance with OAC 165:5-7.
(3) Upon application, notice, and hearing, the Commission may grant or deny an application made pursuant to OAC 165:5-7.

[**SOURCE:** Amended in Rule Making 980000033; Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-3-16. Operation in hydrogen sulfide areas

(a) **Applicability.** Each operator who conducts operations as described in this subsection shall be subject to this Section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide:

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas to the extent as specified in (b) of this Section.

(2) This Section shall not apply to:

(A) Operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modifications, such as refining, petrochemical plants, or chemical plants.

(B) Operations involving gathering, storing, and transporting stabilized liquid hydrocarbons.

(C) Operations where the concentration of hydrogen sulfide in the system is less than 100 PPM.

(b) **General provisions.**

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system. Tests shall be made in accordance with industry standards or other methods approved by the Commission.

(2) For all operations subject to this Section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations or by other methods approved by the Commission such as air dispersion models accepted or approved by the U.S. Environmental Protection Agency:

(A) For determining the location of the 100 ppm radius of exposure: x = [(1.589)(mole fraction H_2S)(Q)] to the power of (.6258).

(B) For determining the location of the 300 ppm radius of exposure: x = [(0.6743) (mole fraction H_2S) (Q)] to the power of (.6258).

(C) For determining the location of the 500 ppm radius of exposure: x = [(0.4546)(mole fraction H_2S)(Q)] to the power of (.6258); **Where: x =** radius of exposure in feet; **Q =** maximum volume determined to be available for escape in cubic feet per day; **H_2S** = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified below as is applicable:

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open flow rate or the operator's estimate of the well's capacity to flow against zero back-pressure at the well head shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 psia and 60° Fahrenheit.

(4) For drilling of a well in an area where insufficient data exists to calculate a radius of exposure but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) As used in this Section, a public area is defined as a dwelling place, business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can reasonably be expected to be populated by humans.

(6) As used in this Section, a public street or road is defined as any federal, state, county or municipal street or road owned or maintained for public access or use.

(7) Facilities where the 100 ppm radius of exposure extends into a public area shall use materials for new construction, or modification of or repairs to existing facilities, subsequent to the effective date of this paragraph, selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under operating conditions for which their use is intended.

(A) Other materials which are non-susceptible to hydrogen sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy applicable industry standards, specifications or recommended practices.

(B) Existing facilities which are in operation prior to the effective date of paragraph (b)(7), above, and where there has been no failure of existing equipment attributed to hydrogen sulfide stress cracking, shall satisfy the requirements of paragraph (b)(7) until such time as the facility experiences a failure.

(8) The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as to prevent hydrogen sulfide stress cracking.

(c) **Storage tank provision.** Storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure and where the vapor accumulation has a hydrogen sulfide concentration that when measured one (1) foot above the open tank thief hatch exceeds 500 ppm, shall be subject to the following:

(1) It shall not be necessary to determine a radius of exposure for storage tanks as described in this Section.

(2) A warning sign shall be posted at the facility which shall meet the following requirements:

(A) A sign shall be located within 50 feet of the facility and be of sufficient size to be readable from the road or at the entrance to the facility.

(B) The warning sign shall state at a minimum that hydrogen sulfide has been found and could be present.

(C) Signs constructed to satisfy paragraph (c)(1) shall use the language **"Caution, Poisonous Gas May Be Present"** using black and yellow colors, or **"Danger Poison Gas (Hydrogen Sulfide)"** using red and white colors or equivalent language. Colors shall satisfy Table 1 of American National Standards Institute Standard 253.1-1967. Signs installed to satisfy paragraph (c)(1) must be compatible with Federal Occupational Safety and Health regulations.

(3) A wind indicator is to be located at the tank battery site so that it may be seen from the entrance to the site and from the storage tanks.

(4) Fencing as a security measure is required when storage tanks are located inside the populated limits of a townsite or city, where conditions cause the storage tanks to be exposed to the public. In other areas where storage tanks may be considered to be a danger the Commission may require a hearing to establish security measures.

(5) **Vapor safety.** A flare, vapor recovery system or H_2S stripping system shall be installed.

(d) **Drilling, completion, workover and production operations.** All operators whose operations are subject to this Section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following:

(1) **Warning and marker provision.**

(A) For aboveground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(B) In populated areas such as townsites and cities where the use of signs is not considered to be appropriate, an alternative warning plan may be approved upon written request to the Commission.

(C) For buried lines subject to this Section, the operator shall comply with the following:

(i) A marker sign shall be installed at public road crossings on both sides of the road as close to the pipeline as possible.

(ii) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(iii) The marker sign shall contain the name of the operator and a 24-hour phone number (including area code), and shall indicate by the use of the words "Warning", "Caution", or "Danger" and "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the Federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to June 12, 1987 shall be acceptable provided they are in good condition and indicate the existence of a potential hazard.

(D) In satisfying the sign requirement of this subsection, the following will be acceptable:

(i) Sign of sufficient size to be readable from the road or at the entrance to the facility.

(ii) New signs constructed to satisfy this subsection shall refer to (c)(2) of this Section.

(2) **Security provision.**

(A) Unattended fixed surface facilities shall be protected from public access when located within one-forth (1/4) mile of a public area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve openings, or other similar means. For the purpose of this paragraph, surface pipeline shall not be considered as a fixed surface facility.

(B) For well sites, fencing as a security measure is required when a well is located inside populated limits of a townsite or city, where conditions cause the well to be exposed to the public. In other areas considered to be a danger, the Commission may require a hearing to establish security requirements.

(C) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(e) **Control and equipment safety; contingency plan.**

(1) **Applicability; radius of exposure.** All operations subject to (a) of this Section shall be subject to (2) and (3) of this subsection, if any of the following conditions apply:

(A) The 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road.

(B) The 500 ppm radius of exposure is in excess of 50 feet and includes any part of a "public road".

(C) The 100 ppm radius of exposure is greater than 3,000 feet.

(2) **Control and equipment safety provision.** Operators subject to this subsection shall either install safety devices and maintain them in an operable condition, or shall establish written safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. Safety devices should be tested annually and a record kept of such tests. All pressure relief safety valves located within the facility shall discharge into a flare system.

(3) **Contingency plan provision.** A contingency plan provision shall be developed for each drilling, producing, well servicing, and plant operation that could reasonably result in accidental exposure of the public to a concentration of hydrogen sulfide in excess of 300 ppm. The operator should make appropriate contacts with any public agency listed in the contingency

plan. The contingency plan shall provide an organized plan of action for alerting and protecting the public. The details of a contingency plan are determined largely by the time required for a potentially hazardous concentration of hydrogen sulfide to reach a public area and by the population density in the public area. A copy of the contingency plan should be maintained at the location which lends itself best to activation of the plan. A copy shall be submitted to the appropriate Conservation Division District Office.

(A) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(B) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(C) The plan shall include a call list which shall include the following as they may be applicable:

(i) Local supervisory personnel.
(ii) County Sheriff.
(iii) Department of Public Safety.
(iv) City Police.
(v) Ambulance Service.
(vi) Hospital.
(vii) Fire Department
(viii) Contractors for supplemental equipment.
(ix) District Commission Office.
(x) Local Department of Environmental Quality Office.
(xi) Other public agencies.

(D) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(E) The plan shall include provisions for advance briefing of occupied dwellings within the 300 ppm radius of exposure. The following provisions apply:

(i) The hazards and characteristics of hydrogen sulfide.
(ii) The necessity for an emergency action plan.
(iii) Possible sources of hydrogen sulfide within the area of exposure.
(iv) Instructions for reporting a gas leak.
(v) The manner in which the public will be notified of an emergency.
(vi) Steps to be taken in case of an emergency.

(F) In a high density population area, or where the population density fluctuates or is difficult to ascertain, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable. The reaction plan option must be approved by the Commission.

(G) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the Commission.

(H) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(f) **Training and requirement provision.** Each operator shall provide appropriate H_2S training for its employees who will be onsite. This training should include:

(1) Hazards and characteristics of hydrogen sulfide.
(2) Effect on metal components of the system.
(3) Operations of safety equipment and life support systems.
(4) First aid in event of an employee exposure.

(5) Use and operation of H_2S monitoring equipment.

(6) Emergency response procedures to include corrective actions, shut-down procedures, evacuation routes, and rescue methods.

(g) **Injection of fluids.** Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this Section unless first approved by the Commission.

(h) **Venting and flaring.**

(1) Venting and flaring of gas shall be conducted in accordance with OAC 165:10-3-15. Vent/flare lines or stacks must have properly installed and operating stack arrestors.

(2) Flaring equipment in public areas shall be designed and installed so as to resist hydrogen sulfide stress cracking. Existing equipment which is in operation prior to the effective date of this paragraph, and where there has been no failure attributable to hydrogen sulfide stress cracking, shall satisfy the requirements of this paragraph until such time as the equipment experiences a failure. Materials used in any new construction, or modification of or repair to existing equipment subsequent to the effective date of this paragraph shall be selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the conditions for which the use of such materials is intended.

(3) Flare systems shall be designed so as to eliminate restrictions and low points creating differential pressure drops in lines which could cause overpressuring of tank hatches.

(4) Flare systems with insufficient pilot fuel gas supply are required to have an alternate fuel gas supply or automated ignition source.

(5) The flare tip shall be required to extend a safe distance from the tank as determined in accordance with API Standard 2000 or similar industry practice.

(i) **Other requirements.** In addition to any other requirements of this Section, drilling and workover operations and processing plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following:

(1) Protective breathing equipment shall be maintained in good operating condition at two or more locations at the site.

(2) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(3) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in harmful concentrations shall be utilized at the site.

(4) The appropriate Conservation Division District Office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this Section.

(j) **Accident notification.** Operators shall immediately notify the appropriate Conservation Division District Office or field inspector of any accidental release of hydrogen sulfide gas of sufficient volume to present a public hazard and hydrogen sulfide related accident resulting in death or hospitalization of personnel.

(k) **Exception provision.** Any application for exception to the provisions of this Section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

(l) **Referenced organizations and publications.** The following organizations and publications are referenced in this Section:

(1) ANSI - American National Standards Institute 1430 Broadway, New York, New York 10018; Table I, Standard 253.1-1967.

(2) API - American Petroleum Institute 300 Corrigan Tower Building, Dallas, Texas 75201; Publication API RP-55 and API Standard 2000.

(3) EPA - U.S. Environmental Protection Agency, Office or Air Quality Planning and Standards, Technical Support Division, Research Triangle Park, North Carolina 27711; Screen 2 Model User's Guide.

[**SOURCE:** Amended at 13 Ok Reg 2395, eff 7-1-96; Amended at 15 Ok Reg 2989, eff 7-15-98 (RM 980000013); Amended at 24 Ok Reg 1784 (RM 200700004), eff 7-1-2007; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-3-17. Well site and surface facilities

(a) **Scope.** This Section shall be applicable to all operators and owners of oil and gas wells, leases, secondary recovery units, converted or newly drilled saltwater disposal or injection wells, and re-entries or reworkings of the above; however, this Section does not cover pits used in connection with oil and gas operations (see 165:10-7-16).

(b) **Removal of fire hazards.** Any material that might constitute a fire hazard shall be removed a safe distance from the well location, tanks, and separator. All waste oil shall be burned or disposed of in a manner to avoid creating a fire hazard.

(c) **Removal of surface trash.**

(1) All surface trash, debris, and junk associated with the operations of the property shall be removed from the premises. Equipment and material that may be useable and related to the operations of the property are not considered trash, debris and junk. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.

(2) If the operator fails to remove trash, debris, and junk after written notice, the Commission may fine the operator up to $1,000.

(d) **Required lease signs.** Within 30 days after the completion of any producing oil or gas well subsequent to the effective date of this Section, a sign shall be posted and maintained at the location indicating no trespassing, no unauthorized personnel or similar language, showing the operator of the well and the operator's twenty-four hour emergency telephone number, name of the well, number of the well, legal description of the well and API number; provided, however, where more than one well is producing on a lease, the operator may post and maintain a sign at the principal lease entrance indicating no trespassing, no unauthorized personnel or similar language, the lease name, operator, the operator's twenty-four hour emergency telephone number, legal description, and number of wells, and on each well designate the number of the well and API number. Within 30 days after completion or recompletion of an enhanced recovery injection well or a disposal well subsequent to the effective date of this Section, a sign shall be posted and maintained at the well location indicating no trespassing, no unauthorized personnel or similar language, showing the operator of the well, the operator's twenty-four hour emergency telephone number, well name, well number, legal description of the well, API number and the Commission order number by which it was authorized. The legal description of each well completed on or after March 1, 1976, shall be posted at the well and shall describe the location of the well to the nearest quarter quarter quarter section and shall show the section, township, and range. On a 160-acre or larger drilling and spacing unit, a sign shall also be posted at the entrance to the well site. Upon the Commission's approval, after the effective date of this Section, of transfer to a new operator of a well completed or recompleted prior to the effective date of this Section, the operator must comply with all requirements in this Section. The appropriate Conservation Division District Office or field inspector may issue Form 1036A for failure to post a required sign. If an operator fails to post a sign as directed, the Commission may fine the operator $50.00 per violation; provided that total fines per incident shall not exceed $500.00 per lease.

(e) **Notice of fire or blowout.** In case of a fire or blowout, the well operator shall notify by telephone or electronic mail, as soon as possible, either the Conservation Division or the appropriate Conservation Division District Office.

(f) **OTC numbers on stock tanks for oil and condensate.**

(1) On all oil and gas producing leases, the first purchaser of crude oil or condensate shall print its name or affix the company logo and print or affix the OTC Gross Production Division Purchaser Reporting Number on the lease sign or at least one of the storage tanks from which marketable liquids are being delivered.

(2) On all oil and gas producing leases, the well operator shall print or affix the OTC Gross Production Division assigned Production Unit Number and the OTC Gross Production Division Operator Reporting Number on the lease sign or at least one of the tanks from which marketable liquids are being stored. In the case of an enhanced recovery or unitization operation where several OTC Gross Production Division assigned Production Unit Numbers exist for the wells in the unit, the word "unitized" shall be printed or affixed to the lease sign or one of the storage tanks from which marketable liquids are being delivered to the purchaser.

(3) The identification numbers required in this subsection shall always be clearly legible. All letters and numbers shall be a minimum of two inches in height. Any operator failing to post required information may be fined up to $50.00 per violation; provided that total fines per incident shall not exceed $500.00 per well.

(g) **OTC numbers on gas meter or meter house.**

(1) On all gas producing leases, the operator of the well site gas meter required under 165:10-17-5 shall print or affix its name and OTC reporting number on the outside of the meter house or on the outside of the meter itself if no meter house exists.

(2) The operator of the lease shall print its OTC lease number and operator reporting number on the meter house or on outside of the meter if no meter house exists.

(3) The identification required in this subsection shall always be clearly legible.

(h) **Valve and seals on stock tanks.** The operator shall install tank valves such that metal identification seals can be properly utilized. These seals shall be used on all delivery tank valves to lessen unauthorized movement of marketable products.

(i) **Man-ways on frac tanks.** Each frac tank used at the wellsite shall have protective man-ways to prevent persons from accidentally falling into the frac tank.

(j) **Guy line anchors.** All guy line anchors left buried for use in future operations of the well shall be properly marked by a marker of bright color not less than four feet in height and not greater than one foot east of the guy line anchor.

(k) **Well site cleared.** Within 90 days after a well is plugged and abandoned, the well site shall be cleared of all equipment, trash, and debris. Any foreign surface material is to be removed and the location site restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the location site is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the well.

(l) **Restored surface.** Within 90 days after a lease has been abandoned, surface equipment such as stock tanks, heater, separators, and other related items shall be removed from the premises. The surface shall be restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the surface is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the lease.

(m) **Leasehold roads.** All leasehold roads shall be kept in a passable condition and shall be made accessible at all times for representatives and field inspectors of the Commission. At the time of abandonment of the property, the

area of the road shall be restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner to leave the surface in some other condition. If the road area is restored but the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the property.

(n) **Extension of time.**

(1) An operator may request an extension of time required in (k), (l), and (m) of this Section for not more than six months by applying to the appropriate Conservation Division District Office and showing that there is no imminent danger to the environment and that one of the following conditions exists:

(A) That an agreement with the surface owners is not possible.

(B) That adverse weather conditions exist or existed.

(C) That the equipment needed to conform to (k), (l), and (m) of this Section was not or is not available.

(2) If approved by the District Manager, the extension shall be granted and the surface owner shall be notified by the operator. Any extension beyond six months shall require application, notice and hearing pursuant to OAC 165:5-7-41.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000034; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 5. OPERATIONS

165:10-3-25. Completion Reports

(a) **Initial Completion Report.** A Completion Report shall be filed with the Commission on Form 1002A within 60 days after completion of operations regardless of whether or not the well was completed as a dry hole, producer, injection, disposal, or service well. An operator who fails to file a complete and correct Form 1002A Completion Report within the allotted time limit may be fined up to $250.00.

(b) **Amended Completion Report. An** amended Completion Report shall be filed with the Commission on Form 1002A within 60 days after completion of operations to reenter, re-complete and/or convert to injection or disposal well regardless of whether or not the well was completed as a dry hole, producer, injection, disposal, or service well.

(c) **No allowable without Completion Report.** The Conservation Division shall not assign an allowable to a well without an up-to-date Completion Report on file with the Conservation Division.

(d) A completion report for any well in a multi-well system shall reference the primary well. An amended completion report for the primary well in a multi-well system shall reference all other wells in the system.

[**SOURCE:** Amended at 9 OK Reg 2295, eff 6-25-92; Amended at 24 Ok Reg 1794 (RM 200700004), eff 7-1-2007; Amended at 28 Ok Reg 1949, eff 7-11-11(RM 201000007); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019)]

165:10-3-26. Well logs

(a) **60 days to submit well log(s).** All well logs required by this Section shall be submitted to the Conservation Division within 60 days from the earlier of the date of completion of the well or the date that the last formation evaluation type well log was run. An operator who fails to properly submit formation evaluation type well logs, if run, may be fined up to $250.00.

(b) **Formation evaluation type well logs.** This Section does not require an operator to run a formation evaluation type well log. However, if an operator does run formation evaluation type well logs, the operator shall only be required under this Section to submit a resistivity log and a porosity log, if available. Resistivity and porosity logs include but are not limited to spontaneous potential, induction, laterolog, density, gamma ray, neutron and sonic logs.

(c) **Other logs to be available upon request.** Any other well logs, if available, shall be submitted to the Technical Services Department upon Commission order or special request of the Conservation Division.

(d) **Requirements for submitting a copy of a log.** A copy of a log submitted under this Section shall be in digital image with the well's legal description noted on it. If there are separate runs for multiple casing strings, the operator shall submit the separate runs.

(e) **Obtaining confidential treatment of well log(s).**

(1) Unless the operator requests confidential treatment of a well log(s), any well log(s) submitted to the Conservation Division shall be available for public inspection.

(2) To obtain confidential treatment of a well log, the operator of the well shall:

(A) Place the well log(s) in a sealed envelope with a completed Form 1002B attached to the envelope.

(B) Submit to the Technical Services Department of the Conservation Division the envelope with the log(s) and Form 1002B within 60 days from the earlier of:

(i) The completion date of the well, or

(ii) The date that the last formation evaluation log was run.

(3) A confidential well log under (2)(B) of this Section, shall remain confidential for one year from the date the last log was run on the well. Upon written request, the Conservation Division may administratively extend the period of confidentiality for six months. Under no circumstances shall confidentiality be granted for a period in excess of 18 months from the date the last log was run on the well.

(f) **No allowable before submission of well logs.** The Conservation Division shall not assign an allowable to a well before the operator of the well submits to the Conservation Division any well log required to be submitted under (b) of this Section.

[**SOURCE:** Amended at 9 OK Reg 2295, eff 6-25-92; Amended at 28 Ok Reg 1949, eff 7-11-11(RM 201000007); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-3-27. Deviation from the vertical

(a) **Well location for purposes of well spacing.** For purposes of the well spacing requirements of 165:10-1-21 and 165:10-1-24, the location of a well in a common source of supply is the closest point to the unit boundary where the wellbore intersects the common source of supply.

(b) **Presumed bottom hole location.** For purposes of review of Form 1000 applications, the Conservation Division may presume that the location in a common source of supply of a well without a horizontal drainhole is the same as the surface location for the well unless:

(1) The operator submits a bottom hole survey, if the well has been drilled; or

(2) The operator complies with (c)(1) of this Section.

(c) **Permitted and prohibited locations.**

(1) **Offpattern surface location; permitted subsurface location.**

(A) The Conservation Division may approve a Form 1000 for a well to be commenced without a location exception at an offpattern surface location for a common source of supply when:

(i) The Form 1000 lists a subsurface location which is a permitted location for the common source of supply.

(ii) Issuance of a Permit to Drill is conditioned on the operator running a bottom hole survey within 30 days after reaching total depth and on the operator submitting the survey to the Conservation Division within 45 days after the well reaches total depth.

(B) The well shall not receive an allowable for the common source of supply until a bottom hole survey shows that the well is at a permitted location or until the operator obtains a location exception order for the subsurface location.

(2) **Offpattern subsurface location.**

(A) The Conservation Division shall not approve a Form 1000 without a location exception order for an offpattern subsurface location.

(B) Issuance of a Permit to Drill under (1) of this subsection does not permit an operator to have, without a location exception order, an offpattern subsurface location for a common source of supply.

(d) **Required directional and bottom hole surveys.** For good cause, the Commission may order an operator to run directional and/or bottom-hole surveys for a common source of supply in a well:

(1) Upon application, notice, and hearing; or

(2) In any case involving the location of a well, upon motion of an affected party or upon the Commission's own motion.

[**SOURCE:** Amended at 24 Ok Reg 1794 (RM 200700004), eff 7-1-2007]

165:10-3-28. Horizontal drilling

(a) **Scope.** This Section affects a horizontal well with one or more laterals.

(b) **Definitions.** The following words and terms, when used in this Section, shall have the following meaning, unless the context clearly indicates otherwise:

(1) **"Adjacent common source of supply"** shall mean a common source of supply which is immediately adjacent to and adjoining the targeted reservoir(s) in a multiunit horizontal well being drilled or a well being drilled in a horizontal well unitization pursuant to 52 O.S. § 87.6 et seq. and which is inadvertently encountered in the drilling of the lateral of a multiunit horizontal well or a well pursuant to a horizontal well unitization when such well is drilled out of or exits, whether on one or multiple occasions, the targeted reservoir(s), and which is not the primary target of the subject well and shall not be included in the relinquished rights pursuant to 52 O.S. § 87.1(h). In the event that an adjacent common source of supply may be inadvertently encountered in the drilling of the lateral of a multiunit horizontal well or a well pursuant to a horizontal well unitization when such well is drilled out of or exits, whether on one or multiple occasions, the targeted reservoir(s), then said inadvertently entered adjacent common source of supply shall be included as part of the targeted reservoir only for the purpose of the inadvertent penetrations, and any subsequent completion, commingling and production of said adjacent common source of supply with the targeted reservoir(s), but not for future development of said adjacent common source of supply [52 O.S. § 87.6(B)(1)].

(2) **"Completion interval"** shall mean, for open hole completions, the interval from the point of entry to the terminus and, for cased and cemented completions, the interval from the first perforations to the last perforations [52 O.S. § 87.6(B)(5)].

(3) **"Conventional reservoir"** shall mean a common source of supply that is not an unconventional reservoir.

(4) **"Date of first production"** shall mean the date hydrocarbons are first produced from the horizontal well, whether or not production occurs during drilling, completion, or through permanent surface equipment.

(5) **"Directional survey"** shall mean that survey or report showing the location of any point of the wellbore as it relates to the surveyed surface location from the surface to the terminus of each lateral.

(6) **"Horizontal component"** shall mean the calculated horizontal distance from the point of entry to the terminus [52 O.S. § 87.6(B)(8)].

(7) **"Horizontal well"** shall mean a well drilled, completed, or recompleted with one or more laterals which, for at least one lateral, the horizontal component of the completion interval exceeds the vertical component of the completion interval and the horizontal component extends a minimum of 150 feet in the formation [52 O.S. § 87.6(B)(6)].

(8) **"Horizontal well unit"** shall mean a drilling and spacing unit established by the Commission, after application, notice, and hearing, for a common source of supply into which a horizontal well has been or will be drilled.

(9) **"Horizontal well unitization"** shall mean a unitization for a targeted reservoir created pursuant to 52 O.S. § 87.6 et seq. [52 O.S. § 87.6(B)(7)].

(10) **"Lateral"** shall mean the portion of the wellbore of a horizontal well from the point of entry to the terminus [52 O.S. § 87.6(B)(9)].

(11) **"Multiunit horizontal well"** shall mean a horizontal well in a targeted reservoir or targeted reservoirs wherein the completion interval of the well is located in more than one unit formed for the same targeted reservoir, with the well being completed in and producing from such targeted reservoir in two or more of such units [52 O.S. § 87.6(B)(10)].

(12) **"Non-standard horizontal well unit"** shall mean a horizontal well unit that is not a standard horizontal well unit.

(13) **"Point of entry"** shall mean the point at which the borehole of a horizontal well first intersects the top of the common source of supply [52 O.S. § 87.6(B)(12)].

(14) **"Standard horizontal well unit"** shall mean a horizontal well unit that is a square 10-, 40-, 160-, or 640-acre tract or a rectangular 20-, 80-, 320- or 1,280-acre tract in accordance with OAC 165:10-1-22.

(15) **"Targeted reservoir"** shall mean one or more common sources of supply which will be encountered by the horizontal lateral portion of a horizontal well, and which has been designated by the Commission as part of an order, rule or emergency rule as potentially suited for development for the applied for multiunit horizontal well or horizontal well unitization pursuant to 52 O.S. § 87.6 et seq. Provided, however, that more than one common source of supply may only be granted by the Commission and included in the targeted reservoir upon a showing of reasonable cause by the applicant requesting the multiunit well in the application requesting authority for the multiunit well prior to the drilling of said multiunit well that the inclusion of the additional common source(s) of supply shall prevent waste and protect the correlative rights of all of the owners of the oil and gas rights [52 O.S. § 87.6(B)(14)].

(16) **"Terminus"** shall mean the end point of the borehole of a horizontal well in the targeted reservoir [52 O.S. § 87.6(B)(15)].

(17) **"True vertical depth"** shall mean that depth at the point of entry perpendicular to the surface as measured from the elevation of the kelly bushing on the drilling rig.

(18) **"Unconventional reservoir"** shall mean a common source of supply that is a shale or a coal bed. "Unconventional reservoir" shall also mean any other common source of supply designated as such by Commission order or rule.

(19) **"Vertical component"** shall mean the calculated vertical distance from the point of entry to the terminus of the lateral [52 O.S. § 87.6(B)(20)].

(c) **General horizontal well requirements.**

(1) Within 30 days after completion of a horizontal well, the operator shall show that the location of the completion interval complies with the applicable general rule, location exception order, or other order of the Commission by submitting the following to the Technical Services Department:

(A) A directional survey run in the horizontal well.

(B) A plat constructed from the results of the directional survey showing the completion interval.

(2) The completion interval of an oil and or gas horizontal well shall be located not closer than the minimum distance as set out below from any other oil or gas well completed in the same common source of supply except as authorized by a special order of the Commission:

(A) Three hundred feet from any other oil or gas well completed in the same common source of supply, the top of which is less than 2,500 feet in true vertical depth.

(B) Six hundred feet from any other oil or gas well completed in the same common source of supply, the top of which is 2,500 feet or more in true vertical depth.

(C) This paragraph does not apply to horizontal wells drilled in a unit created for secondary or enhanced recovery operations pursuant to 52 O.S. § 287.1 et seq. or to horizontal wells drilled in a horizontal well unitization created pursuant to 52 O.S. § 87.6 et seq.

(3) The perforated interval of an oil or gas non-horizontal well shall be located not closer than the minimum distance as set out below from the completion interval of any oil or gas horizontal well completed in the same common source of supply, except as authorized by a special order of the Commission:

(A) Three hundred feet from any completion interval of any oil or gas horizontal well completed in the same common source of supply, the top of which is less than 2,500 feet in true vertical depth.

(B) Six hundred feet from any completion interval of any oil or gas horizontal well completed in the same common source of supply, the top of which is 2,500 feet or more in true vertical depth.

(C) This paragraph does not apply to non-horizontal wells drilled in a unit created for secondary or enhanced recovery operations pursuant to 52 O.S. § 287.1 et seq.

(d) **Horizontal well requirements in an unspaced common source of supply.** In a horizontal well drilled in a common source of supply in which the Commission has not established any drilling and spacing units or horizontal well units, the completion interval of a horizontal well may not be located closer to the boundaries of the applicable mineral estate, oil and gas leasehold estate, or voluntary unit than the minimum distance set out below except as authorized by a special order of the Commission:

(1) Not less than 165 feet when the top of the common source of supply is less than 2,500 feet in true vertical depth.

(2) Not less than 330 feet when the top of the common source of supply is 2,500 feet or more in true vertical depth.

(e) **Drilling and spacing units.**

(1) A horizontal well may be drilled on any drilling and spacing unit.

(2) A horizontal well unit may be created in accordance with 165:10-1-22 and 165:5-7-6. Such units shall be created as new units after notice and hearing as provided for by the Rules of Practice, OAC 165:5.

(3) The Commission may create a non-standard horizontal well unit covering contiguous lands in any configuration or shape deemed by the Commission to be necessary for the development of a conventional reservoir or an unconventional reservoir by the drilling of one or more horizontal wells. A non-standard horizontal well unit may not exceed 1,280 acres plus the tolerances and variances allowed pursuant to 52 O.S. § 87.1.

(4) A horizontal well unit may be established for a common source of supply for which there are already established non-horizontal drilling and spacing units, and said horizontal well unit may include within the boundaries thereof more than one existing non-horizontal drilling and spacing unit for the common source of supply. Upon the formation of a horizontal well unit that includes within the boundaries thereof one or more non-horizontal drilling and spacing units, the Commission shall provide that such horizontal well unit exists concurrently with one or more of such non-horizontal drilling and spacing units, and each such unit may be concurrently developed.

(f) **Horizontal well location requirements for horizontal well units and horizontal well unitizations.**

(1) **Conventional reservoirs.** In a conventional reservoir, the completion interval of a horizontal well in a horizontal well unit shall be located not less than the minimum distance from the unit boundary as follows:

(A) Not less than 165 feet from the boundary of any 10-, 20-, or 40-acre horizontal well unit.

(B) Not less than 330 feet from the boundary of any 80- or 160-acre horizontal well unit.

(C) Not less than 660 feet from the boundary of any 320-, 640- or 1,280-acre horizontal well unit.

(2) **Unconventional reservoirs.** In an unconventional reservoir, the completion interval of a horizontal well in a horizontal well unit shall be located not less than the minimum distance from the unit boundary as follows:

(A) Not less than 165 feet from the boundary of any 10-, 20-, or 40-acre horizontal well unit.

(B) Not less than 330 feet from the boundary of any 80-, 160-, 320-, 640- or 1,280-acre horizontal well unit.

(3) **Horizontal well unitizations.** The completion interval of a horizontal well in a horizontal well unitization shall not be located less than 330 feet from the unit boundary.

(g) **Alternative well location requirements.** The Commission may establish well location requirements different from those provided in subsection (f) of this Section when necessary to prevent waste and protect correlative rights. These requirements may be established in the order creating a standard or non-standard horizontal well unit or through a special rule of the Commission covering a conventional or unconventional reservoir in a designated geographic area. (see OAC 165:10, Subchapter 29, Special Area Rules).

(h) **Allowable.**

(1) Horizontal oil well allowables may be established administratively using the standard allowables provided in Appendix A (Allocated Well Allowable Table) supplemented by the additional allowables provided in Appendix C (Table HD) to this Chapter.

(2) The allowable for a horizontal gas well shall be computed in the manner prescribed for a non-horizontal gas well in the same common source of supply.
(3) The allowable for a horizontal well unit or horizontal well unitization with multiple horizontal gas wells shall be the sum of the allowables for the separate horizontal gas wells. For this summation, the allowable for each horizontal gas well will be calculated as if it were the only well in the unit.
(4) The allowable for a multiunit horizontal well shall be allocated to each affected unit using the allocation factors determined in accordance with 52 O.S. § 87.8(B)(1).

(i) **Pooling.** Horizontal well units, horizontal well unitizations and multiunit horizontal wells may be pooled as provided in 52 O.S. § 87.1, 52 O.S. § 87.6 et seq. and Commission Rules of Practice, OAC 165:5.

[**Source:** Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1894, eff. 5-19-11 (emergency RM 201100004); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-3-29. Oil storage

Oil storage tanks shall be constructed so as to prevent leakage. Dikes or retaining walls, where necessary, shall be constructed, based on tank capacity and throughput, so as to prevent oil or deleterious substances from causing pollution and to ensure public safety.

[**SOURCE:** Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-3-30. Use of gas for artificial lifting

(a) **Use of gas for artificial lifting of oil.** Gas may be used for the artificial lifting of oil; provided, all gas returned to the surface with the oil is not vented or otherwise wasted

(b) **The use of production.** The use of production from one common source of supply to assist in lifting the production from another common source of supply by commingling the production from both common sources of supply in the tubing string shall be permitted when the operator has authority to commingle the production in the tubing.

(c) **Use of artificial lift.** Artificial lift, initial or subsequent, in conjunction with the separate orifice or choke assembly shall be governed by OAC 165:10-3-37.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-31. Use of vacuum at the well head.

(a) **Prohibited without a permit.** Imposing a vacuum on an oil or gas bearing formation is prohibited without a permit from the Commission.

(b) **Requirement.** A vacuum shall not be approved unless it can be shown that use of a vacuum as permitted will prevent waste and protect correlative rights.

(c) **Application for a permit.** Each application for a permit requesting use of a vacuum on a common source of supply shall be filed with the Technical Services Department on Form 1022A. The following information shall accompany the application:
(1) A plat, color coded as to producing zone, showing the locations of all producing wells within one-half (1/2) mile of the well location.
(2) An electric well log of the subject well, if available; otherwise a drillers log concerning the subject well shall be provided.

(d) A copy of the application shall be served, by regular mail, or delivered

to each operator of a producing leasehold within one-half (1/2) mile of the well location. An affidavit reflecting that the required notice was provided shall be filed within five (5) days of filing of the application.
(e) Notice is not required to be published if no written objection to the application is filed or if no hearing is required by the Commission pursuant to subsection (f), below.
(f) If a written objection to the application is filed within fifteen (15) days after the application is filed or if hearing is required by the Commission, then the application shall be set for hearing, and notice thereof shall be given in the same manner specified in OAC 165:5-7-1. If no objection is filed and the Commission does not require a hearing, the matter shall be reviewed administratively by the Director of the Oil and Gas Conservation Division or the Director's designee. If the Oil and Gas Conservation Division denies an application, the applicant may request a hearing on said application.
(g) **Records required to be kept by the operator.**
(1) If an operator obtains a permit authorizing use of a vacuum, the operator shall make a record on a monthly basis of:
(A) The vacuum imposed in pounds per square inch or inches of mercury.
(B) The amount of gas, oil and water production per day from the well.
(2) Any record required to be kept under this Section shall be made available to the Oil and Gas Conservation Division upon request.

[**SOURCE:** Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003)]

PART 7. PRODUCTION

165:10-3-35. Multiple zone production

(a) Production from more than one common source of supply from a single well is hereby prohibited except as authorized by the Conservation Division.
(b) For the purpose of this Section, completion of a well so as to separately produce or account for the production from two or more common sources of supply shall be a multiple completion, and the production from more than one common source of supply without segregation of the production shall be commingling.
(c) Any operator violating this Section shall be subject to a fine of $500.00. The Conservation Division may shut down a multiply completed well pending compliance with this Section.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-36. Multiple zone completions

(a) Each application for the approval of the multiple completion of a well shall be filed with the Technical Services Department on Form 1023.
(b) A copy of the application shall be mailed or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. The applicant shall file an affidavit of delivery or mailing not later than five (5) days after the application is filed.
(c) If a written objection to the application is filed within fifteen (15) days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be reviewed administratively by the Director of Conservation or his designee. If the Conservation Division denies an application, the applicant may request a hearing on said application.

[**SOURCE:** Amended at 16 Ok Reg 2206, eff 7-1-99 (RM 980000033); Amended at 24 Ok Reg 1795 (RM 200700004), eff 7-1-2007; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003)]

165:10-3-37. Control of multiply completed wells

(a) Every multiply completed well shall be equipped, operated, produced, and maintained so that there will be no commingling of the production from separate common sources of supply in the well, except as hereinafter provided. The production from each common source of supply shall be separately accounted for or separately stored and measured on the lease. The production shall be measured by either:

(1) A positive displacement dump-type device;

(2) A continuous-flow measuring device; or

(3) A measuring device of any other type authorized by the Commission.

(b) Each application for the approval of production through a multiple choke assembly in a well shall be filed with the Technical Services Department on Form 1023. The multiple choke assembly must be so designed and located in the wellbore as to prevent commingling within the common sources of supply, but to permit commingling in the tubing string through individual choke orifices. The commingled production shall be measured at the surface and allocated to each common source of supply.

(c) A copy of the application shall be mailed or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. The applicant shall file an affidavit of delivery or mailing not later than five days after the application is filed.

(d) If a written objection to the application is filed within 15 days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be reviewed administratively by the Director of Conservation or his designee. If the Conservation Division denies an application, the applicant may request a hearing on said application.

[**SOURCE:** Amended at 16 OK Reg 2206, eff 7-1-99 (RM 980000033); Amended at 24 Ok Reg 1795 (RM 200700004), eff 7-1-2007; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003)]

165:10-3-38. Testing of multiply completed wells

The Conservation Division may at any time require a multiply completed well to be tested to determine the effectiveness of the separation of common sources of supply. The tests may be witnessed by representatives of the Conservation Division and may be witnessed by any offset operator. Testing procedures must be acceptable to a representative of the Conservation Division.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-3-39. Commingling of production

(a) **Commingling permit required.**

(1) Commingling of production from a well from separate common sources of supply is prohibited without an approved Form 1023 permit. A permit shall be required when production is from more than one source of supply, without segregation of the production in the wellbore, or is produced separately in the wellbore and then combined together downstream of the wellhead prior to measurement. A permit shall be required for horizontal wells with more than one lateral where production in the individual lateral is from separate common sources of supply. A permit shall also be required for horizontal wells where production in uphole zones is from separate common sources of supply. A permit is not required for a multiunit horizontal well or horizontal well involving production from only one lateral. Commingling downstream of the wellhead shall require Form 1024 (Packer Setting Affidavit) and Form 1025 (Packer Leakage Test) to be filed and approved. The Commission may assess a fine up to $500.00 for non-permitted commingling either down hole or downstream prior to measurement.

(2) Each application for the approval of the commingling of a well shall be filed with the Technical Services Department on Form 1023. The following shall be filed with the application:

(A) A well log section with top and bottom of open intervals marked.

(B) A schematic of the proposed completion configuration of the well.

(C) A plat showing the locations of all wells producing from the same common sources of supply within one-half (1/2) mile radius of the subject well.

(3) A copy of the application shall be served, by regular mail, or delivered to each operator of a producing leasehold within one-half (1/2) mile of the well location. An affidavit of mailing shall be filed within five (5) days of filing of the application. No notice is required to be published.

(4) If a written objection to the application for a commingling permit is filed within 15 days after the application is filed, or if hearing is required by the Commission, the application shall be set for hearing, and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be reviewed administratively by the Director of Conservation or his designee. If the Conservation Division denies an application, the applicant may request a hearing on said application.

(b) **Restrictions.**

(1) Commingling shall only be authorized when it would prevent waste and protect correlative rights.

(2) Commingling shall be prohibited where one producing zone is predominately gas and a second zone is predominately oil, unless the operator can verify in writing, submitted with the application, that no cross flow will occur resulting in reservoir damage.

(c) **Commingled allowables.**

(1) **Single allowable for commingled production.** Common sources of supply commingled under this Section receive a single allowable as if they constituted a single common source of supply in the wellbore.

(2) **Gross daily allowable for commingled production.** The gross daily allowable shall be based on the classification of the well as an oil or gas well for allowable purposes under OAC 165:10-13-2.

(A) **Unallocated oil well (GOR < 15,000:1).** The gross daily allowable shall be based on what would be the allowable if commingled production comes from the deepest commingled common source of supply.

(B) **Unallocated gas well (GOR > 15,000:1).** The gross daily allowable shall be a single unallocated gas allowable, as determined by OAC 165:10-17-11(c). Upon request in a commingling application or in any other appropriate application and upon proper notice thereof, the Commission may designate in a commingling permit or other appropriate order the specific gas formation, completed and producing in the applicable well, to which the allowable for such well is to be attributed when the Commission determines that such designation is necessary to prevent waste and to protect correlative rights.

(C) **Special allocated gas pool.** The gross daily allowable shall be based on what would be the allowable if the commingled production came from the special allocated gas pool in the well.

(3) **Operator option if multiple pool rules exist.** If more than one common source of supply under a commingling permit or appropriate order for a gas well is subject to gas pool rules, the order shall designate which set of pool rules is applicable for allowable purposes.

(4) **Net daily allowable.** The net daily allowable is the gross daily allowable under (3) of this subsection:

(A) Reduced accordingly by any penalty against any of the commingled common sources of supply under the permit or appropriate order.

(B) Reduced accordingly by any overage carried forward against a commingled common source of supply.

(C) Increased by any underage carried forward for the well under applicable allocated or special allocated pool rules.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 16 Ok Reg 2206, eff 7-1-99 (RM 980000033); Amended at 24 Ok Reg 1796 (RM 200700004), eff 7-1-2007; Amended at 25 Ok Reg 2187, eff 7-11-08 (RM 200800003); Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-3-40. Production of brine

(a) All wells in excess of 300 feet in depth and producing brine for the extracting of minerals shall be under the full jurisdiction of the Conservation Division.

(b) The establishment of a unitized area for the purpose of efficient operations, prevention of waste, and the protection of correlative rights may be formed by following the procedures set out in 165:5-7-21

(c) Category B surety shall be a requirement for all brine producing wells or units. [See 165:5-7-21(f)]

SUBCHAPTER 5. UNDERGROUND INJECTION CONTROL

165:10-5-1. Classification of underground injection wells

Underground injection wells shall be classified as follows:

(1) **Enhanced recovery injection well.** An enhanced recovery injection well is a well which injects fluids to increase the recovery of hydrocarbons.

(2) **Disposal well.** A disposal well is a well which injects, for purposes other than enhanced recovery, those fluids brought to the surface in connection with oil or natural gas production.

(3) **Storage well.** A storage well is a well used to inject, for storage purposes, hydrocarbons which are liquid at standard temperature and pressure.

(4) **Simultaneous injection well.** A well that injects or disposes of salt water at the same time it is producing oil and/or gas to the surface.

[SOURCE: Amended at 13 Ok Reg 2387, eff 7-1-96]

165:10-5-2. Approval of enhanced recovery injection wells or disposal wells

(a) The subsurface injection or disposal of any substance for any purpose is prohibited except upon approval of the Commission pursuant to 165:10-5-5 or 165:10-5-12 and 165:10-5-13. This authorization may be conditioned upon the applicant taking corrective action to protect treatable water as specified by the Commission. The Commission may fine an operator up to $5,000.00 for any violation of this subsection.

(b) Except as provided in (c) and (d) in this Section, every well used for injection or disposal shall be cased and tested in accordance with 165:10-3-4 and 165:10-5-6.

(c) The testing requirements of 165:10-5-6 shall not apply to wells permitted by Commission order for subsurface injection of onsite reserve pit fluids.

(d) The Conservation Division may approve a Form 1015 application to convert for injection or disposal an existing well which does not comply with 165:10-3-4 if:

(1) The operator attaches to the Form 1015 application a description of an alternate method of protecting treatable water.

(2) The Conservation Division approves the proposed alternate method.

(3) The application is filed in accordance with OAC 165:5-7 if a hearing is required.
(4) The application is not protested.

(e) Any newly drilled or newly converted injection or disposal well which is within one-half (1/2) mile of any public water supply well shall not be approved without notice and hearing, and the Commission shall not issue an order authorizing injection or disposal into said well until the applicant proves by substantial evidence that said well shall not pollute said water supply well. A commercial disposal well shall not be approved within a designated wellhead protection area.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001)]

165:10-5-3. Authorization for existing enhanced recovery injection wells and existing disposal wells

(a) Each enhanced recovery injection well authorized under order of the Commission on the effective date of this Section is an existing enhanced recovery injection well. Injection is prohibited in any existing enhanced recovery injection well unless the operator has included that well on a completed Form 1070 submitted to the Commission within one year following the effective date of this Section. Form 1070 (Inventory of Authorized Existing Enhanced Recovery Injection Wells) shall include each well name, location, authorizing Commission order number (including all orders authorizing exceptions), date of order, maximum authorized injection rate, and maximum authorized injection pressure.

(b) Each disposal well being operated under order of the Commission on the effective date of this Section is an existing disposal well. Injection is prohibited in any existing disposal well unless the operator has included that well on a completed Form 1071 submitted to the Commission within one year following the effective date of this Section. Form 1071 (Inventory of Authorized Existing Disposal Wells) shall include each well name, location, authorizing Commission order number (including all orders authorizing exceptions), date of order, maximum authorized injection rate, and maximum authorized injection pressure.

165:10-5-4. Application for approval of enhanced recovery projects

(a) An enhanced recovery project shall be permitted only by order of the Commission after notice and hearing.

(b) The application for an order authorizing an enhanced recovery project shall contain the following:

(1) The names and addresses of the operator or operators of the project.
(2) A plat showing the lease, group of leases, or unit included within the proposed project; the location of the proposed injection well or wells, and the location of all oil and gas wells including abandoned and drilling wells and dry holes; and the names of all operators offsetting the area encompassed within the project.
(3) The common source of supply in which all wells are currently completed.
(4) The name, description, and depth of each common source of supply to be affected.
(5) A log of a representative well completed in the common source of supply.
(6) A description of the existing or proposed casing program for injection wells and the proposed method of testing casing.
(7) A description of the injection medium to be used, its source, and the estimated amounts to be injected daily.
(8) For a project with an allocated pool, a tabulation showing recent gas-oil ratio and oil and water production tests for each of the producing oil and gas wells.

(9) The proposed plan of development of the area included within the project.

(c) A copy of the application and notice of hearing shall be mailed to the owner or owners of the surface of the land upon which the project is located and to each operator offsetting the project as shown on the application within five days after the application is filed. An affidavit of compliance with this Section shall be filed on or before the hearing.

165:10-5-5. Application for approval of enhanced recovery injection and disposal operations

(a) **Application.** Each application for the approval of a newly drilled or newly converted injection well, disposal well, or commercial disposal well shall be filed with the UIC Department on Form 1015 and shall be verified by a duly authorized representative of the operator.

(b) **Application.** The application for the approval of an enhanced recovery injection or disposal well(s) shall be accompanied by:

(1) **Plat.**

(A) **Noncommercial disposal well.** A plat showing the location and total depth of the well(s) and each abandoned, producing or drilling well, and dry hole within one-quarter (1/4) mile of the enhanced recovery injection well or disposal well, and identifying the surface owner of the land on which the enhanced recovery injection or disposal well is to be located, and each operator of a producing spacing unit or well within one-half (1/2) mile of each enhanced recovery injection or disposal well with a requested injection rate of less than five thousand barrels per day, and each operator of a producing spacing unit or well within one (1) mile of each enhanced recovery injection or disposal well with a requested injection rate of five thousand barrels per day or more.

(B) **Commercial disposal well.** A plat showing the location and total depth of the well(s) and each abandoned, producing or drilling well and dry hole within one-half (1/2) mile of the disposal well, and identifying the surface owner of the land on which the disposal well is to be located, and each operator of a producing spacing unit or well within one (1) mile of each disposal well.

(2) **Completion Report.** If the well has been drilled, a copy of the Completion Report (Form 1002A) and any available electric or radioactivity log of the well.

(3) **Schematic diagram.** A schematic diagram of the well showing:

(A) The total depth or plugback depth of the well.

(B) The depth of the injection or disposal interval indicating both the top and bottom.

(C) The geological name of the injection or disposal zone.

(D) The depths of the tops and bottoms of the casing and cement to be used in the well.

(E) The size of the casing and tubing, and the depth of the packer.

(4) **Proposed zone information.** Information showing that injection into the proposed zone will not initiate fractures through the overlying strata which could enable the injection fluid or formation fluid to enter fresh water strata.

(A) When the fluid injection rate is 1,000 barrels per day or less, or equivalent rate for any fraction of twenty-four (24) hours, an overlying strata of at least 200 feet in thickness between the lowest base of fresh water and the top of the proposed interval of injection is considered sufficient evidence of fresh water protection.

(B) When the fluid injection rate is greater than 1,000 barrels per day or equivalent rate for any fraction of twenty-four (24) hours, an overlying strata of at least 500 feet in thickness between the lowest base of fresh water and the top of the proposed interval of injection is considered sufficient evidence of fresh water protection.

(C) lf the overlying strata is less than required in (A) and (B) of this paragraph, the Commission may administratively approve injection provided a finding is made that such injection will not initiate fractures through the overlying strata into the fresh water strata. Applicant is required to furnish to the Commission, sworn evidence and data in support of such findings. The Commission, when issuing an order approving fluid injection, shall consider the following:

(i) Maximum injection rate.

(ii) Maximum surface injection pressure.

(iii) lnjection fluid.

(iv) The lithology and rock characteristics of the injection zones and overlying strata.

(5) **Proposed operating data:**

(A) Daily injection rates and pressures.

(B) Geologic name, depth, and location of injection fluid source.

(C) Qualitative and quantitative analysis of fresh water from two (2) or more fresh water wells within one (1) mile of the proposed enhanced recovery injection or disposal well showing location of wells and dates samples were taken, or statement why samples were not submitted. The analysis shall include at a minimum chloride, sodium, and total dissolved solids.

(D) Qualitative and quantitative analysis of representative sample of water to be injected. The analysis shall include at a minimum chloride, sodium, and total dissolved solids.

(c) **Application for approval.** A copy of the application for approval of injection or disposal of water or other substances in a well shall be served by the applicant within five (5) days of the date the application is filed by regular mail or delivered to the following:

(1) The owner of the surface of the land on which the proposed injection or disposal well is to be located;

(2) For a proposed commercial disposal well, to each surface owner and surface lessee of record on each tract of land adjacent and contiguous to the site of the proposed well;

(3) For a noncommercial injection or disposal well with a requested injection rate of less than five thousand (5,000) barrels per day, to each operator of a producing spacing unit or well within one-half (1/2) mile of such proposed well;

(4) For a noncommercial injection or disposal well with a requested injection rate of five thousand (5,000) barrels per day or more, or a commercial disposal well, to each operator of a producing spacing unit or well within one (1) mile of such proposed well;

(5) For a noncommercial horizontal injection or disposal well with a requested injection rate of less than five thousand (5,000) barrels per day, to each operator of a producing spacing unit or well within one-half (1/2) mile of the lateral of such proposed well; and

(6) For a noncommercial horizontal injection or disposal well with a requested injection rate of five thousand (5,000) barrels per day or more, or a horizontal commercial disposal well, to each operator of a producing spacing unit or well within one (1) mile of the lateral of such proposed well.

(d) **Notice of application.** Notice of an application relating to injection, disposal or commercial wells shall be published one time for injection and noncommercial disposal wells and two times for a commercial disposal well in a newspaper of general circulation published in Oklahoma County, Oklahoma, and in a newspaper of general circulation published in each county in which land embraced in the application are located. The notice shall include:

(1) UIC tracking number.

(2) Name and address of applicant.

(3) Location of proposed well to nearest 10 acre tract.

(4) Well name.

(5) The geological name of the injection formation.
(6) The top and bottom of the injection interval.
(7) Maximum injection pressures.
(8) Maximum BID or MCFID injection rate.
(9) The type of well (injection, disposal, commercial).

(e) **Written objection.** If a written objection to the application is filed within fifteen (15) days after the application is published for injection and noncommercial disposal wells or thirty (30) days after the last publication date for commercial disposal wells, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given in the same manner as required for the filing of the application on the pollution docket. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Manager of Underground Injection Control who may sign the permit.

(f) **Surety requirements for commercial disposal well facilities.**

(1) Any operator of a commercial disposal well facility shall file with the Manager of Document Handling for the Conservation Division an agreement to properly plug the well and reclaim the site upon termination of operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to comply with Commission rules or take remedial action as required by law and Commission rules, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(2) The Commission shall establish the amount of surety in the order or permit for the authority to operate a commercial disposal well facility. The amount of surety shall be based on factors such as the depth of the well, dimensions of the facility, and costs of plugging the well, reclamation, monitoring, plugging of monitor wells, any pit closure, trucking of any deleterious substances, remediation and earth work. The amount may be subject to change for good cause. The surety shall be maintained for as long as monitoring is required. The type of surety shall be a corporate surety bond, certificate of deposit, irrevocable commercial letter of credit, or other type of surety approved by order or permit of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date.

(3) Operators of commercial disposal well facilities authorized prior to the effective date of this subsection must either comply with this subsection or close such facilities within one (1) year of the effective date of this subsection.

(g) In addition to the requirements listed above, the Manager of Underground Injection Control may request the applicant to submit the following information as a prerequisite to approval of the application:

(1) For those wells included in OAC 165:10-5-5(b)(1) which penetrate the top of the injection interval, a tabulation of the wells indicating the following information, if available, from public records:

(A) Dates the wells were drilled.
(B) The present status of the wells.
(C) The identity of any abandoned well which was improperly plugged or remains unplugged.

(2) A list of the following information, if available, to the applicant:

(A) The shut-in bottom hole formation pressure in psi; or the stabilized shut-in surface pressure and fluid level in the proposed injection well.
(B) The permeability of the proposed injection zone expressed in millidarcies.
(C) The porosity of the proposed injection zone expressed as a percentage of pore volume.
(D) Documentation of the methods used to arrive at the data requested above.

(h) Authorization of an enhanced oil recovery injection well or a disposal well or a commercial disposal well will expire and become null and void if no well completion report (Form 1002A) is filed or if no mechanical integrity test is performed pursuant to OAC 165:10-5-6 within six months from the date of completion or conversion of the well.

(i) In addition to the well construction requirements as set out in 165:10-3-1, commercial saltwater disposal wells shall comply with the following requirements:

(1) At a minimum, the well shall be constructed with a wellhead, surface casing, production casing, tubing, and packer.

(2) The surface casing shall be set and cemented at least fifty (50) feet below the base of the treatable water bearing zone. The production casing will not be allowed to also serve as the surface casing.

(3) The production casing must be set and cemented through the injection zone with the cement circulated behind the casing to a height at least two hundred fifty (250) feet above the disposal zone. A cement bond log showing quality and placement of the cement must be furnished to and approved by the Commission before the well may be used for injection or disposal. The Manager of Underground Injection Control may approve the Arbuckle Formation for open hole completion.

(4) The annulus between the tubing and the casing must be open from the surface to the packer to allow for pressure testing and monitoring of the injection tubing and packer and the annulus filled with a packer fluid that protects against corrosion.

(5) The packer must be set at least within seventy-five (75) feet of the top of the perforations.

(6) Adequate gauges shall be installed on each annulus to allow proper monitoring of the disposal operation.

(7) Tubing must be internally coated or lined to prevent corrosion from injected fluids. PVC, Plastic Coated, Stainless Steel or Fiberglass will qualify.

(8) The packer must be either internally coated or stainless steel.

(9) Commercial disposal wells authorized with a positive injection pressure must be equipped with a down hole shut-off device with a seal divider installed between the packer and the tubing. A Stainless Steel Profile Nipple and an "ON-OFF" Tool will qualify under this Section.

(j) No Commercial disposal well will be permitted whose injection pressure approaches or exceeds the demonstrated frac gradient of the injection zones(s).

(k) All permitted injection zones must be completed for injection. Authorization for any zones not initially completed as an injection zone will expire within 60 days following initial completion or recompletion date.

(l) In the event the Commission has evidence that an applicant for a commercial disposal well may not possess a satisfactory compliance history with Commission rules, the Director of the Conservation Division may seek an order of the Commission, issued after application, notice, and hearing, determining whether the applicant should be authorized to operate such commercial disposal well.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019)]

165:10-5-6. Testing and monitoring requirements for enhanced recovery injection wells and disposal wells

(a) **Mechanical integrity during injection.** The operator of an injection, disposal or commercial disposal well must maintain mechanical integrity in order to continue operation of the well.

(b) **Initial pressure test requirements for wells permitted on or after December 2, 1981.**

(1) **Mandatory initial mechanical test.** Before commencement of operation, each well authorized for enhanced recovery injection or disposal by a Commission order issued on or after December 2, 1981, must pass an initial pressure test of the casing tubing annulus according to the minimum testing standards of (2) of this subsection, unless a Commission order or permit authorizes other test procedures of the mechanical integrity of the well. Any operator failing to comply with initial mechanical integrity testing and reporting requirements may be fined up to $500.00.

(2) **Minimum testing standards for initial tests.** For each initial test required by (1) of this subsection, the minimum testing standards are:

(A) **Witnessing of the test.** The test shall be witnessed by an authorized representative of the Conservation Division. It shall be the responsibility of the well operator to secure the presence of the Commission representative.

(B) **Down-hole equipment.** Injection and disposal shall be through adequate tubing and packer.

(C) **Aboveground extensions and fittings.** Adequate aboveground extensions shall be installed in each annulus in the well. In addition, the operator shall install a one-fourth (1/4) inch female fitting, with cutoff valve to the tubing, so that the amount of injection pressure may be measured by the Commission representative using a gauge having a one-fourth (1/4) inch male fitting.

(D) **Packer setting depth under the order.** The mechanical packer shall be set within 40 feet of the packer setting depth prescribed by the order permitting the well for injection or within 75 feet of the perforations of the injection zone(s) opened.

(E) **Verification of packer setting depth.** The Commission District Manager may require the operator of the well to verify the packer setting depth by running a wireline or other method approved by the Manager of the Underground Injection Control Department.

(F) **Minimum testing pressure.** Noncommercial disposal and injection wells shall be tested as follows:

(i) If the maximum authorized injection pressure for the well is less than 300 psig under the order or permit authorizing the well for injection, the minimum testing pressure shall be 300 psig.

(ii) If the maximum authorized injection pressure is greater than 300 psig under the order or permit authorizing the well for injection, the minimum testing pressure shall be the lesser of 1000 psig or the maximum authorized injection pressure under the order permitting the well.

(G) **Thirty minute minimum testing period.** The minimum testing period shall be 30 minutes at the testing pressure.

(H) **Ten percent maximum permitted bleed-off.** The maximum permitted bleed-off during the testing period shall be ten percent of the maximum testing pressure used.

(I) **Test report on Form 1075.** The operators shall submit the results of the mechanical integrity test on Form 1075 within 30 days from the date the test is performed.

(J) **Cement circulated above injection zone.** The minimum cement height circulated above the injection or disposal zone in the annulus between the casing and the borehole shall be 250 feet.

(K) **Packer setting depth.** The packer must be set at a depth which is at least 50 feet below the depth of the top of cement behind the production casing.

(3) **Alternative testing procedures.** Operators can test at a maximum of 500 psi if there is in place an automatic and continuous pressure monitor on the tubing-casing annulus that will shut-in the well if there is a pressure increase of 250 psi on the annulus. Application for this alternative test

procedure shall be made in writing to the Manager of the UIC Department. The Manager of the UIC Department may allow the alternative test procedure to be used as the initial mechanical integrity test, which permission shall be reflected in the order or permit regarding the well.

(4) **Use of fluid seal without a mechanical packer.** Use of a fluid seal without a mechanical packer is prohibited.

(c) **Initial pressure test requirements for wells permitted prior to December 2, 1981.**

(1) **Mandatory initial pressure test or monitoring test.**

(A) Each well authorized for enhanced recovery injection or disposal by Commission order issued prior to December 2, 1981, must pass an initial mechanical integrity test according to the minimum testing standards of (2) of this subsection.

(B) In lieu of casing test required in (A) of this paragraph, the operator shall monitor and record during actual injection the pressure in the casing-tubing annulus monthly and report the pressure annually on Form 1075. A measurable positive pressure must be maintained at the casing valve and be continuously measured to qualify.

(2) **Minimum testing standards for initial mechanical integrity tests.**

(A) **Wells with casing-tubing annulus.** The minimum testing standards of (b)(2) of this Section for an initial test of a well with a casing tubing annulus shall apply with the following modifications:

(i) The District Manager shall have the option to waive witnessing of the test.

(ii) If the test is not witnessed, the well operator shall submit documentation of the test to the Conservation Division within 30 days after the test on Form 1075.

(iii) The minimum testing pressure shall be 200 psig.

(B) **Wells without a casing-tubing annulus or wells with perforations above the packer.** The minimum testing standards for an initial test of a well without a casing-tubing annulus or wells with perforations above the packer are:

(i) **Witnessing of the test.** The test shall be witnessed by an authorized representative of the Conservation Division unless the District Manager for the Conservation Division waives the requirement of witnessing the initial test. It shall be the responsibility of the well operator to secure the presence of the commission representative for witnessing the test.

(ii) **Documentation for unwitnessed tests.** If the test is not witnessed, then the operator shall submit on Form 1075 documentation of the test to the Conservation Division within 30 days after the test.

(iii) **Aboveground extensions and fittings.** The operator shall install a one-fourth (1/4) inch female fitting, with cutoff valve to the tubing, so that the amount of injection pressure may be measured by the Commission representative using a gauge having a one-fourth (1/4) inch male fitting.

(iv) **Setting depth for plug.** For purposes of the test, a mechanical packer, retrievable bridge plug, or seating nipple plug shall be placed in the injection string not more than 75 feet above the top of the injection interval.

(v) **Pressure testing of tubing string.** The well operator shall pressure test the tubing string for at least 30 minutes. The minimum testing pressure shall be the greater of 300 psig, or the maximum authorized injection pressure provided that the actual working injection pressure for the well may be used instead of the maximum authorized injection pressure when necessary to prevent damage to the casing or packer.

(vi) **Ten percent maximum permitted bleedoff.** The maximum permitted bleedoff during the testing period shall be ten percent of the maximum testing pressure used.

(vii) **Radioactive tracer survey.** A radioactive tracer survey shall be run demonstrating that the injected fluid is going into the authorized zone when there is no cement bond log or cementing reports to demonstrate sufficient cement behind pipe to isolate the injection zone or to insure the packer is properly set.

(viii) **Pressure test using a gas media.** In lieu of a pressure test using a liquid testing media, the UIC Department may approve a mechanical integrity test using a gas media if it conforms to a method previously approved by the EPA.

(ix) **Test report on Form 1075.** The operator shall submit the results of the mechanical integrity test on Form 1075 to the Conservation Division within 30 days after the test.

(d) **Subsequent mechanical integrity test requirements.**

(1) **Pressure tests.**

(A) **Disposal wells permitted for injection at volumes equal to or greater than 20,000 barrels per day.** Unless a well has been approved by an order or permit of the Commission for other testing procedures or monitoring, each disposal well permitted for injection at volumes equal to or greater than 20,000 barrels per day shall demonstrate mechanical integrity by using one of the following methods:

(i) Conduct a pressure test of the casing tubing annulus at least once every year according to the minimum testing standards of (3) of this subsection, or

(ii) If a continuous pressure monitor is installed on the casing tubing annulus that will automatically notify the operator of a mechanical failure, then the well shall demonstrate mechanical integrity at least once every five years according to the minimum testing standards of (3) of this subsection.

(B) **Disposal wells permitted for injection at volumes less than 20,000 barrels per day and enhanced recovery injection wells.** Unless a well has been approved by an order or permit of the Commission for other testing procedures or monitoring, each disposal well permitted for injection at volumes less than 20,000 barrels per day, and each enhanced recovery injection well permitted for injection shall demonstrate mechanical integrity at least once every five years according to the minimum testing standards of (3) of this subsection.

(C) **Penalty for noncompliance.** Any operator failing to comply with periodic mechanical integrity testing and reporting requirements may be fined up to $500.00.

(2) **Required retest if down-hole equipment is moved or replaced.** After a well passes a pressure test required by this Section, if the operator moves the packer or replaces either the packer or the tubing, then the operator shall retest the well according to the minimum testing standards of (3) of this subsection.

(3) **Minimum testing standards.**

(A) **Wells with casing-tubing annulus.** For a five year test or retest required by this subsection, the minimum testing standards of (b)(2) of this Section shall apply to wells with casing-tubing annulus with the following modifications:

(i) The District Manager shall have the option to waive witnessing of the test.

(ii) If the test is not witnessed, the well operator shall submit documentation of the test to the Conservation Division within 30 days after the test.

(iii) The minimum testing pressure shall be:

(I) 200 psig for a noncommercial well.

(II) 300 psig or the authorized injection pressure, whichever is greater, for commercial disposal wells.

(B) **Wells without a casing-tubing annulus or wells with perforations above the packer.** For a five year test or retest required by this subsection, the minimum testing reporting standards of (c)(2)(B) of this Section, shall apply to wells without a casing-tubing annulus or wells with perforations above the packer.

(C) **Wells with automatic monitoring of positive tubing-casing pressure.** Subsequent pressure tests will not be required if there is in place a pressure monitor on the annulus to demonstrate the maintenance of a certain, positive pressure. This monitor will be connected to an automatic alarm or a continuous chart recorder. Application for this alternative shall be made in writing to the Manager of the UIC Department. Monitoring records will be sent to the UIC Department annually attached to Form 1012 or semi-annually attached to Form 1012C.

(e) **Monitoring requirements.**

(1) **Report on Form 1075.** In lieu of a mechanical integrity test every five years, the operator of a well permitted for injection or disposal may demonstrate the mechanical integrity by:

(A) Monitoring and recording the injection rate, volume, and casing-tubing annulus pressure monthly.

(B) Submitting to the Conservation Division the results of monthly monitoring for the calendar year on Form 1075 by the first day of April of the next calendar year.

(2) **Required positive casing-tubing annulus pressure.** A measurable positive pressure must be maintained at the casing valve and be continuously measured to qualify for mechanical integrity.

(f) **Testing requirements for commercial disposal wells.**

(1) **Before commencement of operation.** Before commencement of operation, each commercial disposal well must pass a pressure test of the casing tubing annulus.

(2) **Minimum testing standards.**

(A) The test shall be witnessed by an authorized representative of the Conservation Division.

(B) The well shall be tested at the maximum authorized injection pressure, but not less than 300 psig.

(C) The minimum testing period shall be thirty (30) minutes.

(D) The maximum allowable change in pressure during the testing period shall be ten percent (10%) of the testing pressure.

(E) The results of the test shall be submitted on Form 1075 within 30 days from the date of the test.

(3) **Subsequent mechanical integrity tests.**

(A) The well shall be tested a minimum of every twelve (12) months.

(B) After a well passes a pressure test required by this Section, if the operator moves the packer or replaces the packer or tubing, then the operator shall notify the Commission and retest the well according to the minimum testing standards of (2) of this subsection.

(4) **Alternative testing procedures.** Operators can test at a maximum of 500 psi if there is in place an automatic and continuous pressure monitor on the tubing-casing annulus that will shut-in the well if there is a pressure increase of 250 psig on the annulus. Application for this alternative test procedure shall be made in writing to the Manager of the UIC Department. The Manager of the UIC Department may allow the alternative test procedure to be used as the initial mechanical integrity test, which permission shall be reflected in the order or permit regarding the well.

(g) **Fluid level monitoring required by UIC orders or permits to address wells ascertained during the permitting process that may require remediation.**

(1) **Fluid level monitoring.** The operator must perform on an annual basis fluid level monitoring tests if required by a UIC order or permit.

(2) **Fluid level test procedures.**

(A) Unless otherwise stated in UIC orders or permits for fluid level monitoring, the well must be shut in for a minimum of 48 hours before a fluid level test is performed. A variance to the 48-hour shut-in period may be granted by the Manager of the UIC Department if it can be demonstrated that reservoir pressure will stabilize prior to the expiration of the 48-hour time period.

(B) Fluid level test procedures shall be designed to determine reservoir pressure and such tests must be approved by the Conservation Division.

(C) The appropriate Field Inspector shall be notified at least 48 hours in advance of a fluid level test to allow a Commission representative an opportunity to witness the test.

(D) The operator is required to submit the annual monitoring test results by June 30 of each year to the Manager of the Underground Injection Control Department.

(3) **Fluid level monitoring test failure.** If the fluid level in a well is determined to be within 150 feet or less below the base of treatable water, the test shall be deemed a failure, and the following actions must be performed:

(A) The operator shall immediately cease injection or disposal operations.

(B) The operator shall notify the Manager of the Underground Injection Control Department of the results within 24 hours of the performance of the fluid level test, and shall submit the results of the test and a corrective action plan in writing to such Manager within 7 days of the test.

(4) **Failure to perform fluid level test.** Any operator who fails to perform annual fluid level tests as required by a UIC order or permit pursuant to this subsection is subject to the following:

(A) Injection or disposal into the UIC well is prohibited until the operator performs the test and submits the results to the Manager of the Underground Injection Control Department.

(B) The operator may be fined up to $1,000.00, and

(C) The UIC order or permit is subject to termination after notice and hearing.

[SOURCE: Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 13 Ok Reg 2387, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200000002, eff 7-1-2000; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-5-7. Monitoring and reporting requirements for wells covered by 165:10-5-1

(a) **Scope.** This Section applies to:

(1) Notice of Initial Commencement of Disposal Operations.

(2) Report of Injection Projects, saltwater disposal wells and LPG storage wells on Form 1012 or Form 1012C.

(3) Notice of Voluntary Termination of Operations on Form 1072.

(4) Notice of mechanical failure or down-hole problems on Form 1075.

(b) **Notice of initial commencement of disposal operations.** The operator of a well permitted as a disposal well in the Arbuckle formation shall give at least 48 hours notice by electronic mail or facsimile to the Manager of Underground Injection Control regarding the time when initial disposal operations will begin.

(c) **Report of enhanced recovery injection projects, saltwater disposal wells and LPG storage wells.**

(1) **Submit Form 1012.** Each operator of a saltwater disposal well, LPG storage well or an authorized waterflood, pressure maintenance project, gas repressuring project, or other enhanced recovery project shall submit Form 1012 for every well to the Conservation Division by January 31 for the previous calendar year for all noncommercial wells.

(2) **Submit Form 1012C.** Each operator of a commercial disposal well shall submit Form 1012C for every well to the Conservation Division by January 31 and July 31 for the previous six-month period.

(3) **Failure to submit Form 1012 or Form 1012C.** Any operator who fails to submit the report on Form 1012 or Form 1012C as required by (c)(1) and (c)(2) of this Section may be fined up to $500.00 and:

(A) Injection into the project is prohibited until the operator submits Form 1012 or Form 1012C for each injection or disposal well.

(B) The order or permit is subject to termination.

(4) **Required monitoring.**

(A) On a monthly basis, the operator of each enhanced recovery injection well and disposal well and LPG storage well shall monitor and record the injection rate and surface injection pressure for the well.

(B) On a daily basis, the operator of each well authorized for disposal into the Arbuckle formation shall monitor and record the volumes, the casing tubing annulus pressure and the surface injection pressure for the well. The operator must maintain the information required by this subparagraph for a minimum of three years. This information shall be produced upon request by an authorized representative of the Commission.

(5) **Requested monitoring and reporting within areas of interest regarding seismicity.** Upon request by the Manager of the Pollution Abatement Department, the following actions must be performed and the information provided to the Manager of the Pollution Abatement Department:

(A) Operators shall monitor on a daily basis volumes and pressures for wells authorized for disposal within areas of interest designated by the Oil and Gas Conservation Division regarding seismicity. The information shall be submitted on Form 1012D at a minimum on a weekly basis or as designated by the Manager of the Pollution Abatement Department.

(B) Operators of wells authorized for disposal within areas of interest designated by the Oil and Gas Conservation Division regarding seismicity shall supply bottom hole pressure data using a method approved by the Manager of the Pollution Abatement Department.

(6) **All UIC wells.** Saltwater disposal wells, injection wells and storage wells shall be reported on Form 1012 or Form 1012C individually according to the order or permit authorizing disposal.

(d) **Monitoring requirements for commercial disposal well.**

(1) The operator of a commercial disposal well shall monitor and record the casing tubing annulus pressure and the injection pressure on a daily basis.

(2) The operator of a commercial saltwater disposal well shall make available upon request of the Commission a log of all loads of deleterious substances disposed at the well. The log shall be kept on file for a period of at least five (5) years. The log of record shall include at a minimum, the date and time the load was received, the volume, the legal description of the well and/or source, and the operator and/or owner of the source of the deleterious substance.

(e) **Notice of voluntary termination.**

(1) If an operator permanently terminates injection into a well, the operator shall submit to the Conservation Division Form 1072 within 30 days after termination of injection. Form 1072 shall state:

(A) The legal description of the well.

(B) The reason for termination.

(C) The status of other wells, if the well is in an enhanced recovery project.

(2) Submission of Form 1072 to permanently terminate injection shall terminate the authority under the order.

(f) **Notice of mechanical integrity problem.**

(1) **Notice of mechanical failure or down-hole problem.** When a mechanical problem occurs, then:

(A) The well operator shall notify the Field Inspector for Conservation within 24 hours after discovery of the problem.

(B) Within five days after discovery of the problem, the well operator shall submit to the Manager of Underground Injection Control written notice of the failure and a plan to repair and/or retest the well.

(C) Repair shall be reported on the Form 1012 or Form 1012C for the well.

(D) Any operator failing to timely notify the Commission may be fined up to $1,500.00.

(2) **Notice of unreported repairs.** Any prior unreported repair of the well shall be reported on the next Form 1012 or Form 1012C to be submitted to the Manager of the UIC Department.

(g) **Shutdown or other action.**

(1) **Administrative shutdown or other action regarding a well.** The Conservation Division may shut down or take other action, including the issuance or execution of administrative agreements, regarding a well pursuant to 17 O.S. § 52, 52 O.S. §139(D)(1) and other applicable authority, to address matters including, but not limited to, seismic activity, or if a mechanical failure or down-hole problem indicates that injected substances are not or may not be entering the injection interval authorized by order or permit of the Commission.

(2) **Request for technical conference.** If an operator objects to the shutdown or other action regarding its well by the Conservation Division, the operator shall submit a written request for a technical conference to the Director of the Conservation Division or designee within five business days of the date of the shut down notice or other Conservation Division action regarding the well. If a resolution of the shutdown or other action regarding the well is not reached by the operator and the Conservation Division after a technical conference occurs, then the provisions of paragraph (5) below are applicable.

(3) **Failure to request a technical conference.** Except for good cause shown, if an operator fails to timely submit a written request for a technical conference pursuant to paragraph (2) above, such failure shall be deemed to constitute an agreement by the operator to the shutdown or other Conservation Division action regarding the well.

(4) **Administrative authority to recommence injection.** After receiving a written request for a technical conference from an operator pursuant to paragraph (2) above, the Conservation Division may consider, but not be limited to, the following in determining whether the operator will be authorized to recommence injection into the well:

(A) the mechanical integrity of the well for injection; and

(B) if construction of the well demonstrates the injected substances are going into and are confined to the permitted injection interval.

(5) **Resolution of disputes by order of the Commission.** In the event of a dispute between the Conservation Division and the operator as to the suitability of a well for injection, the operator or the Conservation Division may seek relief by order of the Commission. Upon application, notice, and hearing pursuant to OAC 165:5-7-1 and other applicable Commission rules, the Commission may issue an order determining whether or not the well should be used for further injection.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 13 Ok Reg 2389, eff 7-1-96; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 Ok Reg 2128, eff 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-5-8. Liquid hydrocarbon storage wells

Authorization for storage wells will be granted by order of the Commission after notice and hearing, provided there is a finding that the proposed operation will not endanger fresh water strata.

165:10-5-9. Duration of underground injection well orders or permits

(a) Subject to 165:10-5-10, 52 O.S. §139(D)(1) and other applicable authority, authorization of injection into enhanced recovery injection wells and disposal wells shall remain valid for the life of the well, unless revoked by the Commission for just cause or lapses and becomes null and void under the provisions of 165:10-5-5(h).

(b) An order or permit granting underground injection may be suspended, modified, vacated, amended, or terminated during its term for cause. This may be at the Commission's initiative or at the request of any interested person through the prescribed complaint procedure of the Conservation Division. All requests shall be in writing and shall contain facts or reasons supporting the request.

(c) An order or permit may be suspended or temporarily modified by the Commission pursuant to 52 O.S. §139(D)(1), 165:10-5-7(g) and other applicable authority.

(d) An order or permit may be permanently modified, vacated, amended, or terminated after notice and hearing if:

(1) There is a substantial change of conditions in the enhanced recovery injection well or the disposal well operation, or there are substantial changes in the information originally furnished.

(2) Information as to the permitted operation indicates that the cumulative effects on the environment are unacceptable.

(e) If an operator fails to complete or convert a well as approved by the Conservation Division within eighteen (18) months after the effective date of the order or permit authorizing injection into the well, then the order or permit authorizing injection into the well shall expire.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-5-10. Transfer of authority to inject

(a) An order or permit authorizing an enhanced recovery well(s), salt water disposal well, commercial salt water disposal well, or hydrocarbon storage well(s) shall not be transferred from one operator to another without the following:

(1) The new operator, or transferee, must comply with 165:10-1-10 before a change in operator is approved.

(2) Change of operator Form 1073I or Form 1073IMW must be signed by both the transferor and transferee, with both stipulating that the facts presented are true and correct as to the area covered and the wells being transferred. The new operator shall file Form 1073I or Form 1073IMW to notify the Conservation Division of any change of operation of any underground injection well within thirty (30) days of transfer of the well.

(3) Notice in writing to the Commission on Form 1073IMW. For transfers involving more than ten (10) wells, a transferor and transferee may file a single Form 1073IMW with the Conservation Division indicating the transfer of multiple wells, provided that such multiple well transfer shall be accompanied by a well list containing the following information for each well transferred:

(A) API number of the well;

(B) Well name and number;

(C) Legal location of the well, described by section, township and range; and

(D) The Commission Order or permit number(s) authorizing the injection, disposal, or hydrocarbon storage activity.

(4) The well list may be provided in spreadsheet form, if possible, and may be filed in digital format specified by the Conservation Division. In lieu of the information listed in subparagraphs (a)(3)(A) through (D), the transferor and transferee, at their option, may file one Form 1073IMW indicating the transfer of multiple wells with an OCC Form 1002A Completion Report attached for each well transferred. Upon review by the Conservation Division, it may require additional information from the transferor and/or the transferee to assist in identifying the specific well(s) being transferred. The additional information may include, but not be limited to, the quarter, quarter, quarter section calls, footages from the south and west quarter section lines, and the drilling and completion dates, and initial injection, disposal or storage dates.

(5) Notice in writing to the Commission on Form 1075 demonstrating that a mechanical integrity test was performed within one year prior to the date of transfer. For commercial disposal wells, the Mechanical Integrity Test shall be conducted within 30 days prior to the date of transfer.

(6) The performance of the mechanical integrity test required in (a)(5) of this subsection shall not apply to any operator transfer when the following conditions are present:

(A) The interest of the currently designated operator is transferred to its subsidiary or parent company, or a subsidiary of a parent company;

(B) The interest of the currently designated operator is transferred to a surviving or resulting corporation or business entity due to, respectively, a merger, consolidation or reorganization involving the transferor and transferee. As used in this subparagraph, "business entity" means a domestic or foreign partnership, whether general or limited; limited liability company; business trust; common law trust, or other unincorporated business; or

(C) The currently designated operator undergoes a name change. The relief afforded by this subparagraph is not applicable to situations where the name change involves the following conditions:

(i) The assignment of a new Federal Employer Identification number by the Internal Revenue Service to the new company;

(ii) The name change is accompanied by a change in the majority of partners in a partnership;

(iii) The name change is associated with a divorce between a husband and wife when the husband and wife comprise a partnership;

(iv) The name change is associated with the death of one spouse in a partnership comprised of a husband and wife;

(v) The name change involves a sole proprietorship; or

(vi) The name change is associated with such other circumstances where the Commission determines upon application, notice and hearing that the relief provided in this subparagraph is not applicable, or that an exception to any exclusion should be granted.

(vii) As used in this subparagraph, the term "partnership" means a domestic or foreign partnership, whether general or limited.

(7) A Form 1012 or Form 1012C for that portion of the calendar year the transferor has operated the well prior to submitting the Form 1073I to the Commission.

(b) The Conservation Division shall notify both the transferor and transferee in writing within thirty (30) days of the Conservation Division's approval or disapproval of the transfer of authority to inject for the subject well(s).

(c) If an operator is not in compliance with an enforceable order or permit of the Commission, the Conservation Division shall not approve any Form 1073I or Form 1073IMW transferring well(s) to said operator until the operator complies with the order or permit. The transferor of the well(s) listed on the Form 1073I or Form 1073IMW remains responsible for the well(s) until any transfer is approved by the Commission.

[**SOURCE:** Amended at 13 Ok Reg 2390, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200000002, eff 7-1-00; Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019)]

165:10-5-11. Notarized reports

In lieu of notarization, all Conservation Division reports shall contain the following statement signed and dated by the responsible party representing the entity which is submitting the report:

"I declare that I have knowledge of the contents of this report, which was prepared by me or under my supervision and direction, with the data and facts stated herein to be true, correct, and complete to the best of my knowledge and belief".

165:10-5-12. Application for administrative approval for the subsurface injection of onsite reserve pit fluids

Except upon a case-by-case approval of the Commission pursuant to 165:10-5-13, the subsurface injection of reserve pit fluids is prohibited into:

(1) A newly drilled well which is to be plugged and abandoned, or

(2) The casing annulus of:

(A) A well being drilled.

(B) A recently completed well.

(C) A well which has been worked over.

165:10-5-13. Application for permit for one time injection of reserve pit fluids

(a) **General.**

(1) Injection of reserve pit fluids shall be limited to injection of only those fluids generated in the drilling, deepening, or workover of the specific well for which authorization is requested.

(2) An annular injection site shall be inspected by a duly authorized representative of the Commission prior to injection.

(3) The applicant shall file with the Underground Injection Control an affidavit of delivery or mailing not later than five days after the application is filed.

(4) An operator who disposes of drilling fluid into the surface casing or annulus without approval from the Manager of Pollution Abatement may be fined up to $2,500.00.

(b) **Criteria for approval.**

(1) Intermediate casing injection may be authorized if injection will not endanger treatable water and provided that intermediate casing is set at least 200 feet below the base of treatable water, except as otherwise provided by the Commission.

(2) Injection pressure shall be limited so that vertical fractures will not extend to the base of treatable water.

(3) **Required form and attachments.** Each application for annular injection shall be submitted to the UIC Department on Form 1015T. The form must be properly completed and signed. Attached to the form shall be the following:

(A) Affidavit of mailing a copy of the Form 1015T or Form 1000 to the landowner and to each operator of a producing lease within 1/2 mile of the subject well.

(B) Cement Bond Log of subject well (if run).

(4) **Expiration of the permit.** The permit shall expire on its own terms three months after the date of issuance of the permit.

(c) **Emergency authority to inject into the annulus.** The Manager of the UIC Department may grant emergency authority to inject pit fluids into the annulus provided an imminent environmental endangerment exists.

(d) **Protest period.** If no protest is received within 15 days of the mailing of Form 1015T, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 13 Ok Reg 2390, eff 7-1-96; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001]

165:10-5-14. Exempt aquifers

(a) Upon application after notice and hearing, the Commission may issue an order designating an underground source of drinking water (USDW) as an exempted aquifer if the USDW:

(1) Does not currently serve as a source of drinking water.

(2) Cannot now and has no reasonable future prospect of serving as a source of drinking water because:

(A) It is mineral, hydrocarbon or geothermal energy producing source; or

(B) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or

(C) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.

(b) For purposes of 165:10-3-4 and 165:10-5-2 through 165:10-5-13, an exempted aquifer shall not be considered as productive of treatable water.

(c) Each application under subsection (a) of this Section shall comply with 165:5-7-28.

(d) Each order designating a USDW as an exempted aquifer shall be subject to approval by the U.S. Environmental Protection Agency.

165:10-5-15. Application for permit for simultaneous injection well

(a) **General.**

(1) Simultaneous injection of salt water without a valid permit from the Underground Injection Control Department may result in the assessment of a fine up to $5,000 per day of operation.

(2) A simultaneous injection facility shall be inspected by a representative of the commission prior to operation.

(b) **Criteria for approval.**

(1) Simultaneous injection may be permitted if the following conditions are met and injection will not adversely affect offsetting production nor endanger treatable water.

(A) Injection zone is located below the producing zone in the borehole.

(B) Injection pressure is limited to less than the local fracture gradient.

(C) If injection is by gravity flow, no Area of Review will be required.

(D) If injection is by positive pump pressure, a 1/4 mile Area of Review will be required. If unplugged or mud-plugged boreholes are located within the 1/4 mile radius, the operator of the proposed simultaneous injection well will be required to reconcile these boreholes prior to a permit being issued.

(E) Simultaneous injectors must meet the requirements of 165:10-3-4 as they apply to producing wells.

(F) Simultaneous injectors may be authorized to accept produced water from other wells. The UIC Department will determine on a case-by-case basis whether such a well warrants designation as a simultaneous injector, or whether the well requires a Commission order.

(2) **Required form and attachments.** Each application for simultaneous injection shall be submitted to the UIC Department on Form 1015SI in

quadruplicate. The forms must be properly completed and signed. Attached to one copy of the application form shall be the following:

(A) Affidavit of mailing a copy of the completed Form 1015SI to each operator of a producing lease within 1/2 mile of the subject well.

(B) Schematic diagram of the well showing all casing and tubing strings, packers, perforations and pumps.

(3) **Monitoring, testing and reporting requirements for simultaneous injection wells.**

(A) Upon receiving a permit, operator shall file an amended Completion Report Form 1002A within 30 days of recompletion.

(B) Mechanical integrity will be demonstrated by filing annual reports of surface casing pressure, production casing pressure and fluid level.

(C) Annual Report Form 1012 shall be submitted by January 31 of each year for the previous calendar year and semi-annual report Form 1012C shall be submitted by January 31 and July 31 of each year for the previous six-month period.

(4) If no protest is received within 15 days of the mailing of Form 1015SI, the application shall be submitted for administrative approval. If a protest is received within the protest period, the operator shall, within 30 days, set and give proper notice of a date for hearing on the Pollution Docket before an Administrative Law Judge.

(c) **Expiration of the permit.** The permit shall expire on its own terms if the subject well is not recompleted or if a revised Form 1002A is not submitted within 180 days from the date on the permit.

[SOURCE: Added at 13 Ok Reg 2391, eff 7-1-96; Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

SUBCHAPTER 7. POLLUTION ABATEMENT

PART 1. GENERAL PROVISIONS

PART 2. ANODE GROUNDBEDS

PART 3. STORAGE AND DISPOSAL OF FLUIDS

PART 1. GENERAL PROVISIONS

165:10-7-1. Pollution abatement [RESERVED]

165:10-7-2. Administration and enforcement of rules

(a) The Manager of Pollution Abatement shall supervise and coordinate the administration and enforcement of the rules of this Subchapter under the direction of the Director of Conservation and the Commission.

(b) Site assessments and remediation projects for petroleum and produced water pollution should adhere to the general practices appearing in the Oil and Gas Conservation Division's Guardian Guidance document including the Guidelines and Numerical Criteria for New or Historic Produced Water/Brine Spills Appendix. Any alternative plan shall be approved by the Manager of Pollution Abatement prior to implementation.

(c) **Specific areas of Conservation Division jurisdiction to which Pollution Abatement rules apply:**

(1) Field operations for geologic and geophysical exploration for oil, gas and/or brine, including seismic shot holes, stratigraphic test holes or other test wells.

(2) Exploration, drilling, development, production or processing of oil, gas and/or mineral brine at the lease site.

(3) The exploration, drilling development and operation of wells used in connection with the recovery, injection, or disposal of mineral brines including construction, operation, maintenance, closure and abandonment of the facilities and activities.

(4) Reclaiming and/or recycling facilities associated with the exploration, drilling, development, production or transportation of oil and/or gas (including the processing of saltwater, crude oil, natural gas condensate, tank bottoms or basic sediment from crude oil tanks, pipelines, pits and equipment).

(5) Underground injection control pursuant to the federal Safe Drinking Water Act and 40 CFR parts 144 through 148 for Class II injection wells, Class V wells used for the recovery, injection or disposal or mineral brines as defined in the Oklahoma Brine Development Act.

(6) Tank farms for storage of crude oil and petroleum products located outside the boundaries of refineries, petrochemical manufacturing plants, natural gas liquid extraction plants, or other facilities that are not subject to the jurisdiction of the Oklahoma Department of Environmental Quality.

(7) Construction and operation of pipelines and associated rights-of-way, equipment, facilities or buildings used in the transportation of oil, gas, petroleum, petroleum projects, anhydrous ammonia or mineral brine, or in the treatment of oil, gas or mineral brine during the course of transportation [not including pipelines in natural gas liquids extraction plants, refineries, or reclaiming facilities other than those specified in OAC 165:10-7-2(c)(6).

(8) The handling, transportation, storage and disposition of saltwater, drilling fluids, mineral brines, waste oil and other deleterious substances produced from or obtained or used in connection with the drilling, development, production, and operation of oil and gas wells at any facility or activity specifically subject to Commission jurisdiction or other oil and gas extraction facilities and activities.

(9) Spills of deleterious substances associated with facilities and activities specified in OAC 165:10-7-2(c)(8) or otherwise associated with oil and gas extraction and transportation activities.

(10) Groundwater protection for activities subject to the jurisdictional areas of environmental responsibility of the Commission.

(d) **Monitoring of sites.** Before consideration for closure by the Conservation Division or the Commission, the responsible party shall monitor a remediation

project subject to implementation of the water quality standards for a period of one (1) year, unless:

(1) Otherwise provided by Commission order, or

(2) As directed by the Manager of Pollution Abatement or designated Conservation Division staff.

(e) **Public participation; Resolution of complaint or disagreement with Conservation Division staff.**

(1) In any case where the Conservation Division determines the need for public participation in the resolution of a pollution complaint involving the implementation of the water quality standards or other issues relating to pollution, the Conservation Division may file an application and notice of hearing to request resolution of the complaint by adjudicative hearing and Commission order.

(2) In any case where a pollution complaint involving the implementation of the water quality standards or other issues relating to pollution cannot be resolved administratively between the responsible party and the complainant or because of a disagreement with the Conservation Division's manager of Pollution Abatement, Manager of Field Operations, or other Conservation Division staff, regarding the complaint, the responsible party or the complainant may file an application and notice of hearing to request resolution of the complaint by adjudicative hearing and Commission order.

[**SOURCE:** Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-3. Cooperation with other agencies

(a) The rules of this Subchapter shall not be construed as modifying the rights, obligations, or duties of any person under any law of this State or under any order, rule, or regulation of the Oklahoma Water Resources Board, State Department of Health, Oklahoma Wildlife Conservation Commission, State Board of Agriculture, Department of Environmental Quality, or any other agency of this State with respect to the pollution of fresh water.

(b) Whenever a written complaint against any person is filed with the Commission alleging pollution as prohibited by 165:10-7-5, the Manager of Pollution Abatement shall immediately initiate such action as may be necessary or appropriate to abate the pollution.

(c) OPERATORS TAKE NOTE: Federal statutes, such as the Bald Eagle Protection Act (16 U.S.C. Sections 668-668d), the Migratory Bird Treaty Act (16 U.S.C. Sections 703-711), the Endangered Species Act (16 U.S.C. Sections 1531-1542), and the Lacey Act Amendments of 1981 (16 U.S.C. Sections 3371-3378), dictate substantial fines and penalties for persons who allow birds of certain species to become fatally injured due to incidental contact with oil or oil by-products. These fines may be levied upon persons allowing such fatalities to occur, whether accidental or not. Misdemeanor and felony convictions may include imprisonment. Information on affected bird species, regulations under these Acts, and measures which can be taken to prevent such occurrences, such as the netting or covering of open-topped tanks and pits which contain oil or oil by-products, can be obtained from the U.S. Fish and Wildlife Service Office in Oklahoma City or the nearest Oklahoma Department of Wildlife Office.

(d) **Operators drilling in the Arbuckle-Simpson Aquifer.** The Arbuckle-Simpson Aquifer located in Pontotoc, Murray, and Johnston Counties has unique and unusual hydrogeologic conditions. Any operator intending to drill in this area should contact the Technical Services Department of the Oil and Gas Conservation Division prior to filing an intent-to-drill. The Technical Services Department may request a technical meeting prior to approval of an intent-to-drill to determine if additional protection of this aquifer is necessary.

[SOURCE: Amended at 23 Ok Reg 2229, eff 7-1-06 (RM 200600012); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003)]

165:10-7-4. Water quality standards

(a) **Scope.** The Commission hereby adopts the State water quality standards established and promulgated by the Oklahoma Water Resources Board (OWRB) or its successors effective October 7, 1987, and additions and revisions as lawfully published in the Oklahoma Register effective as provided by statute. The Commission's Oil and Gas Conservation Division (Conservation Division) shall implement the water quality standards with regard to its particular jurisdictional areas as referred to in 165:10-7-2(c).

(b) **General considerations.**

(1) The primary goal of the implementation of the water quality standards in the context of a remediation project subject to Commission jurisdiction shall be the protection and/or restoration of the beneficial use of the land, the soil and any surface or subsurface waters of the State adversely impacted or impaired by pollution from a Commission regulated site or facility.

(2) A remediation project utilizing the water quality standards shall adhere to the general practices appearing in the Conservation Division's *Oklahoma Water Quality Standards Implementation Plan (WQSIP)*.

(3) Where appropriate, a remediation project utilizing the water quality standards shall follow the use support assessment protocols (OWRB-OAC 785:46-7) as specified in *Oklahoma Water Quality Standards Implementation Plan*.

[**SOURCE:** Amended in Rule Making 200100005, eff 7-1-01; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-7-5. Prohibition of pollution

(a) **General.** Pollution is prohibited. All operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons shall at all times conduct their operations in a manner that will not cause pollution.

(b) **Workable coal seams.** Sections 305, 306, 307, and 308 of Title 52, Oklahoma Statutes Annotated, governing the drilling, operations, and plugging of oil and gas wells in workable coal beds are hereby adopted as rules of the Commission as fully as if set out verbatim herein.

(c) **Reporting nonpermitted discharges (spills, etc.).**

(1) All operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons conducting operations regulated by the Commission shall:

(A) Report verbally, with respect to their operations, to the Commission District Office or Field Inspector within 24 hours of discovery:

(i) Any non-permitted discharge of deleterious substances of ten bbls. or more (single event) to the surface.

(ii) Any discharge of a deleterious substance, regardless of quantity, to the waters of the State.

(B) File a written or oral report with the District Office within ten business days specifying the following:

(i) Name of party reporting, firm name, telephone number, and electronic mail address.

(ii) Legal location.

(iii) Lease or facility name.

(iv) Operator.

(v) Circumstances surrounding discharge of deleterious substance(s) and whether discharge was to water or soil.

(vi) Date of occurrence.

(vii) Volumes of deleterious substance(s) discharged.

(viii) Type of materials discharged.
(ix) Method of cleanup (if any) undertaken and completed.
(x) Volumes of deleterious substance(s) recovered.

(C) Maintain adequate records of each non-permitted discharge reflecting the information, time, and manner of reporting pursuant to this Section for a minimum of three (3) years.
Such documents shall be produced upon demand by an authorized representative of the Commission.

(D) Report hazardous substances that meet reportable quantities under Comprehensive Environmental Response Compensation and Liability Act (CERCLA) (40 C.F.R. Part 302) in the format as required under this subsection.

(2) Any operator, contractor, driller, service company, pit operator, transporter, or pipeline company who fails to comply with provisions of this rule may be fined $500.00 per incident.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-7-6. Protection of public water supplies

The Commission, upon application of any municipality or other governmental subdivision, may enter an order establishing special field rules within a defined area to protect and preserve fresh water and fresh water supplies.

[**SOURCE:** Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-7-7. Informal complaints, citations, red tags, and shut down of operations

(a) This Section applies only to Field Operations Department of the Oil and Gas Conservation Division.

(b) For an alleged violation of an order or provision of this Chapter, a district manager or field inspector may attempt to contact the alleged violator or his agent, in person or by telephone. The Form 1036A shall be used for purposes of the monetary fines procedure in 165:10-7-9. Mailing of either form may be to the last known address of the alleged violator according to Commission records.

(c) Where surface or subsurface pollution is apparent, a district manager or field inspector may direct an alleged violator to take steps necessary to stop and/or clean up pollution. Said steps may include a temporary shut down of the lease or facility. If an alleged violator cannot be located, the district manager or field inspector may take emergency action necessary to abate pollution.

(d) If the inspection shows that the alleged violator failed to comply as directed, the district manager or field inspector may:

(1) Issue a Form 1036A, where applicable,

(2) Refer the matter to the Office of General Counsel for prosecution, and/or

(3) Temporarily shut down the lease or facility until further notice from the Commission.

(e) In shutting down a lease or facility, the district manager or field inspector shall affix at the site a red tag (directive to shut down). If the alleged violator removes or ignores a red tag, the district manager or field inspector shall refer the matter to the Office of General Counsel for prosecution, and the Commission may levy a fine up to $5,000.00.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-8. Inspection and enforcement [RESERVED]

165:10-7-9. Scheduled monetary fines

(a) **Scope.** This Section prescribes amounts and procedure for imposing monetary fines arising from the categories of rule violations shown on Schedules A and B, Appendix E and F, respectively to this Chapter.

(b) **Issuance of complaint-citations.**

(1) If the Conservation Division discovers an alleged violation in any category on Schedule A, it may issue a complaint-citation on Form 1036A. Said form shall describe the alleged rule violation, and it shall prescribe a monetary fine.

(2) If the Conservation Division discovers an alleged violation in any category on Schedule B, it may issue a complaint-citation on Form 1036A. Said form shall describe the alleged rule violation. It shall establish a time period for compliance without a monetary fine. It shall prescribe a Schedule B fine if the alleged violator fails to comply with Commission rules within the specified time period for compliance.

(c) **Notice.** Any complaint-citation (OCC Form 1036A) issued under this Section shall be mailed or delivered to the alleged violator at the last known address shown on Commission records.

(d) **Hearing option.**

(1) Any alleged violator shall have the option to pay the prescribed fine or contest it at an evidentiary hearing. Payment of the fine within the time provided on the complaint-citation shall be considered and accepted as a plea of no contest.

(2) To obtain an evidentiary hearing, the alleged violator must request it at the preliminary hearing described on the complaint-citation. Failure to timely request an evidentiary hearing may result in an order assessing the fine prescribed by the complaint-citation.

(3) Appeal from any report of the Administrative Law Judge shall be to the panel of Commissioners in accordance with the Rules of Practice, OAC 165:5.

(e) **Payment of fines.** A person may pay a fine with cash, a money order, or check; provided, that any cash payment must be made at a Commission cashier's window. All checks must be made payable to the Oklahoma Corporation Commission. A copy of the complaint-citation must accompany payment to ensure proper credit.

(f) **Additional enforcement measures.**

(1) The Conservation Division and the Secretary of the Corporation Commission may issue one or more complaint-citations to a person who fails to bring a lease and/or facility into compliance with the rules of this Chapter.

(2) Until payment in full or payment schedule has been determined, the Conservation Division may shut-down any lease and/or facility associated with an overdue fine assessed by Commission order after notice and hearing.

[**SOURCE:** Added at 9 Ok Reg 2295, eff 6-25-92]

165:10-7-10. Registration for land application of deleterious substances

(a) All persons who contract to land apply fluids pursuant to OAC 165:10-7-17, OAC 165:10-7-19, OAC 165:10-7-26 or OAC 165:10-9-2 shall:

(1) Comply with OAC 165:30-3-11, OAC 165:30-3-13, all applicable laws and all applicable Commission rules regarding Deleterious Substance Transport Permits; and

(2) Submit to the Conservation Division a performance bond in the amount of $50,000.00, or other form of surety in an amount as approved by the Manager of the Pollution Abatement Department. The form of surety shall include an irrevocable commercial letter of credit, cash, a cashier's check, a certificate of deposit, a blanket surety bond, or other approved negotiable instrument. Financial statements are not an acceptable form of surety. The surety may be released upon request made no sooner than thirty

(30) days subsequent to the completion of operation(s) that have been permitted under such surety, if Conservation Division personnel determine, after inspection or review, that the release of surety is appropriate.

(b) Any person violating this Section may be fined in an amount up to $2,500.00. Any operation in violation of this Section may be shut down pending compliance with this Section.

[**SOURCE:** New at 30 Ok Reg 1041, eff 7-1-13 (RM 201300001)]

PART 2. ANODE GROUNDBEDS

165:10-7-14. Anode groundbeds

(a) **Definitions.** The following words or terms, when used in this Section, shall have the following meaning, unless the context clearly indicates otherwise:

(1) **"Anode"** means the electrode of an electrochemical cell at which oxidation occurs.

(2) **"Cathodic protection"** means a technique used to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

(3) **"Deep anode groundbed"** means one or more anodes installed vertically at a depth of fifty (50) feet or more below the earth's surface in a drilled hole for the purpose of providing cathodic protection.

(4) **"Shallow anode groundbed"** means one or more anodes installed either vertically or horizontally at a nominal depth of less than fifty (50) feet.

(5) **"Annular space"** means the space between the surface casing and the borewall or the space between two or more strings of casing placed in the borehole.

(6) **"Operator"** means the person who is duly authorized and in charge of the development of the operation of the pipeline or the development of a lease for the production of hydrocarbons.

(b) **Permit to drill.**

(1) The operator shall make application on Form 1000B and obtain a permit to drill a deep anode groundbed.

(2) A permit to drill shall be valid only for one or more deep anode groundbeds within a designated 10 acre tract.

(3) The Commission shall approve or deny the application within 30 days of date of receipt.

(4) Any contractor drilling a deep anode groundbed shall be licensed within the State of Oklahoma.

(5) Any operator who drills a deep anode groundbed without a permit may be fined up to one thousand dollars ($1,000.00).

(c) **Expiration.** A permit to drill shall expire six (6) months from the date of issuance, unless drilling operations are commenced.

(d) **Posting of permit to drill at the site.** During any activity subject to this Section the operator shall maintain at the site a legible copy of the permit to drill for inspection.

(e) **Notice.** The Commission's District Manager or Field Inspector shall be given at least twenty-four (24) hours notice prior to commencing drilling operations.

(f) **Notice of failure to comply with permit conditions.** The operator shall notify the district office or the field inspector within twenty-four (24) hours of any failure to comply with the construction requirements approved on the permit.

(g) **Deep anode groundbed abandonment.**

(1) In the event the hole is lost during drilling, the hole will be plugged as soon as possible.

(2) Upon abandonment of a deep anode groundbed, the hole shall be plugged within thirty (30) days of abandonment.

(h) **Construction standards.**

(1) **Shallow anode groundbeds.**

(A) Shallow anode groundbeds shall be constructed in order to prevent runoff water from entering the anode system or the commingling of water from separate groundwater bearing formations.

(B) Vertical shallow groundbeds shall be sealed by backfilling the hole with native cuttings or an approved sealing material.

(2) **Deep anode groundbeds.**

(A) Deep anode groundbeds shall be constructed in order to prevent runoff water from entering the anode system or the commingling of groundwater formations with different water quality.

(B) Surface casing shall be set a minimum of twenty (20) feet below ground level, or at a depth previously approved by the Oil and Gas Division's Technical Department.

(C) If surface casing is not placed in the hole, the hole shall be filled with bentonite or cement from the top of the Coke Breeze Column to three (3) feet below surface. Native cuttings or soil shall be used to fill the remaining portion of the hole.

(D) The annular space between the casing and drilled hole shall be a minimum of two (2) inches to allow for a proper seal.

(E) The sealing material for the annular space for surface casing shall be bentonite, cement or a material previously approved by the Oil and Gas Division's Technical Department.

(F) Centralizers shall be used at a minimum of one (1) for every twenty-five (25) feet of surface casing run in the hole unless previously approved by the Oil and Gas Division's Technical Department on form 1000B.

(G) The groundbed shall be capped to prevent the entry of foreign material. Allowances for a vent pipe will be approved.

(i) **Groundbed materials.** Groundbed materials that do not contaminate groundwater shall be required at all times.

(j) **Plugging requirements.**

(1) All wires and vent pipe must be cut off at the top of the ten (10) foot surface plug, and the vent pipe must be securely capped and plugged.

(2) Cased holes shall be filled to at least ten (10) feet from the surface with native cuttings, anode materials, cement or with a material approved by the Pollution Abatement Department.

(3) Cement or bentonite shall be placed in the hole at a minimum of ten (10) feet below the surface to within three (3) feet of the surface. The remainder of the hole shall be filled with native cuttings, soil or a material approved by the Pollution Abatement Department.

(4) If the standard method is inadequate to stop artesian flow, alternate remedies must be employed to do so.

(5) All holes shall be properly completed or plugged to protect groundwater.

[**SOURCE:** Added in Rule Making 97000002, eff 7-1-97; Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007)]

PART 3. STORAGE AND DISPOSAL OF FLUIDS

165:10-7-15. Drilling or seismic activity near superfund sites or hazardous waste facilities

Any drilling or seismic activity related to oil or gas exploration or production shall be prohibited within 500 feet of the boundary of any superfund site pursuant to the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), 42 U.S.C. Sections 9601, et. seq., or active hazardous waste treatment, storage, or disposal facility. A current listing of all superfund sites and active hazardous waste facilities is available from the Manager of Pollution Abatement. Seismic work, monitoring wells, or recovery wells necessary for identification, monitoring, or remediation of the superfund site or hazardous waste facility shall be exempt from this Section. Any request for exception to this Section shall comport

with the requirements generally for filing of applications under the Commission's Rules of Practice (see 165:5-7-1); in addition, notice shall be given to the Oklahoma State Department of Health, 1000 Northeast Tenth Street, Oklahoma City, Oklahoma 73152.

165:10-7-16. Use of noncommercial pits

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for any noncommercial pit. A noncommercial pit is an earthen pit which is located either on-site or off-site and is used for the handling, storage, or disposal of drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste. This does not cover disposal well pits. (See 165:10-7-20 and 165:10-9-3.)

(b) **Liner requirements.**

(1) **Reserve/circulation and/or completion/fracture/workover pits.**

(A) To assist in determining the construction requirements for a particular proposed reserve/circulation pit, either on-site or off-site, the operator of the pit shall indicate on Form 1000 the type of mud system(s) to be used, the maximum and average anticipated chloride concentration of the mud (based on drilling records in the area), whether or not pit fluids will be segregated, and shall furnish other information required by this Section or requested by the Commission's Technical Services Department.

(B) The Commission's Technical Services Department shall evaluate the site based upon Oklahoma Geological Survey maps and other pertinent information and shall assign one of the following categories to any proposed reserve/circulation pit, designating same on Form 1000 and indicating whether or not a liner is required:

(i) **Category 1A – Geomembrane liner.**

(I) **Water based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a alluvial deposit or in a near surface static water level environment.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/ workover fluids located in alluvial deposit area or an area where the static water table is within 10 feet of the surface shall utilize a geomembrane liner for all drilling fluids and cuttings and/or completion/ fracture/ workover fluids.

(II) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located within a wellhead protection area.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/fracture/workover fluids located within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 U.S.C. Section 300h-7, Safe Drinking Water Act), or within one mile of public water well for which the WPA has not been delineated, shall be required to have a geomembrane liner.

(ii) **Category 1B – Soil liner or geomembrane liner.**

(I) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a terrace deposit.** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/ workover fluids located over a terrace deposit shall be required to have either a soil liner or a geomembrane liner.

(II) **Water-based drilling fluid containment and/or water-based completion/fracture/workover fluid containment located over a bedrock aquifer or Hydrologically Sensitive Area (HSA).** Any pit used to contain water-based drilling fluids, cuttings and/or completion/ fracture/workover fluids located over any bedrock aquifer or HSA and is used to contain water-based drilling fluids

and/or cuttings and/or completion/fracture/workover fluids with chlorides in excess 5,000 mg/l shall be required to have a soil liner or a geomembrane liner. A separate unlined pit may be used to contain fluids and/or cuttings with a chloride content of less than of 5,000 mg/l.

(iii) **Category 2 - Water-based/other situations.** Any pit which is used to contain water-based drilling fluids, cuttings and/or completion/fracture/ workover fluids with a set of conditions different from Categories 1A and 1B shall not be required to be lined.

(iv) **Category 3 - Oil-based.** Any pit used to contain oil-based drilling fluids, cuttings and/or completion/fracture/workover fluids shall be required to have a geomembrane liner.

(v) **Category 4 – Air-based.** Any pit used to contain the cuttings from an air-based system shall not be required to be lined. The discharge of produced water into a category 4 pit is prohibited.

(2) **Other type pits.**

(A) Any basic sediment pit shall be required to have a geomembrane liner.

(B) Any emergency pit shall not be required to be lined.

(C) Any flare pit shall not be required to be lined.

(D) Any recycling/reuse pit, spill containment pit, slit trench, or remediation pit shall conform to the same criteria for determining liner requirements for reserve/circulation and/or completion/fracture/workover pits, pursuant to (b)(1) of this Section.

(3) **Converted pits.** Any pit that is to be converted from one use to another, e.g., reserve pit to completion or fracture pit, shall have the more stringent liner requirements, pursuant to (c)(6) and (c)(7) of this Section.

(4) **Offsite pits.** Any offsite pit shall conform to the liner requirements in this Section and will require a permit. The operator of the proposed pit shall submit Form 1014 to the appropriate Conservation Division District Office for review and approval. No offsite reserve pit may be permitted or constructed at a spacing closer than one pit per governmental quarter quarter section and a distance less than 600 feet from any other pit. Any offsite reserve pit may be reclassified or considered as a commercial pit, pursuant to 165:10-9-1, if it is constructed or used at a spacing closer than one reserve pit per governmental quarter quarter section. Closure of any offsite reserve pit shall not warrant the permitting of another offsite reserve pit within the same governmental quarter quarter section. For use of a pit without a permit, the pit operator may be fined up to $1,000.00.

(5) **Variances.** Any variance from the liner requirements of this Section may be granted by the Manager of the Technical Services Department after receipt of a written request and supporting documentation required by the Department.

(c) **Construction requirements.**

(1) **Field or area rules.** Any noncommercial pit which is to be constructed or used in an area covered by a field or area rule shall be subject to the more stringent requirements of either this Section or the field or area rule.

(2) **Stockpiling of topsoil.** Prior to constructing any noncommercial pit, except an emergency pit, all top soil within the top twelve inches shall be stripped and stockpiled for use as the final cover of fill at the time of closure. The top soil may be stockpiled in the berms, provided it is not mixed with other materials and can be readily distinguishable from other materials at the time of closure.

(3) **Exclusion of runoff water.** Any noncommercial pit shall be constructed and maintained so that runoff water from outside the location is not allowed to enter it.

(4) **Flood protection.** Any noncommercial pit which is constructed in any area subject to frequent flooding according to the Soil Conservation Service County Soil Survey shall have berms substantial enough to prevent overtopping or washing out.

(5) **Constructing on fill.** Any noncommercial pit which requires a liner and is constructed on fill shall be constructed so that the maximum level of the solid contents will be maintained at least three feet below the natural ground level.

(6) **Soil liners.**

(A) Soil materials used or to be used in a soil liner shall undergo permeability testing either before or after construction, unless exempt pursuant to (B) of this paragraph.

(i) Pre-construction permeability testing shall consist of laboratory permeability tests on at least two specimens of representative soil liner materials compacted in the laboratory to approximately 90 percent of the material's Standard Proctor Density (ASTM D-698).

(ii) Post-construction permeability testing shall consist of at least two laboratory permeability tests on undisturbed samples of the completed soil liner or one field permeability test on the completed soil liner. Particular emphasis shall be placed on selecting the location(s) for permeability tests or test samples where nonuniformity in soil texture or color can be observed.

(iii) Laboratory permeability test procedures must conform to one of the methods described for fine-grained soils in the Corps of Engineers Manual EM-1110-2-1906 Appendix VII. In no case shall the pressure differential across the specimen exceed five feet of water per inch of specimen length. Field permeability tests shall be conducted only by the double ring infiltrometer method as described in ASTM D-3385. Permeability tests may be discontinued prior to flow stabilization upon satisfactory evidence that the permeability rate is less than 1.0×10^{-6} cm/sec.

(iv) If permeability testing shows that addition of bentonite or other approved material is needed to assist the native soils in meeting the permeability standard, it shall be applied at a minimum rate specified by the testing or engineering firm. Any bentonite used for liner material shall not have been previously used in drilling muds.

(B) Permeability testing requirements for soil materials may be exempt if laboratory testing of a minimum of two representative samples of the soil materials found throughout the entire depth of the proposed excavation indicates that the plasticity index is greater than 16 (ASTM D-4318) and that the amount passing the No. 200 U.S. standards sieve is greater than 60 percent (ASTM D-1140).

(C) Any soil liner shall be constructed by disturbing the soil to the depth of the bottom of the liner, applying fresh water as necessary to the soil materials to achieve a moisture content wet of optimum, then recompacting it with heavy construction equipment, such as a footed roller, until the required density is achieved, pursuant to (H) of this paragraph.

(D) Any soil liner shall cover the bottom and interior sides of the pit entirely.

(E) Any soil liner shall be installed on a slope no steeper than 3:1 (horizontal to vertical).

(F) Any soil liner shall have a minimum thickness of six inches (after compaction), and shall have a maximum coefficient of permeability of 1.0×10^{-6} cm/sec, unless it conforms to (G) of this paragraph.

(G) A soil liner may have a coefficient of permeability greater than 1.0×10^{-6} cm/sec if it is greater in thickness and constructed in accordance with the following:

(i) A minimum twelve inch compacted soil liner shall have a maximum coefficient of permeability of 2.0×10^{-6} cm/sec.

(ii) A minimum 18 inch compacted soil liner shall have a maximum coefficient of permeability of 3.0×10^{-6} cm/sec.

(iii) A compacted soil liner may not be constructed thicker than 18 inches for the purpose of meeting a coefficient of permeability greater than 3.0×10^{-6} cm/sec.

(iv) Any soil liner with a minimum twelve inch or 18 inch thickness shall be constructed in maximum lifts of six inches (after compaction). Each lift shall be scarified before placement of the next lift and shall conform to (H) of this paragraph.

(H) Any soil liner shall be field tested for compaction, unless a post-construction permeability test is performed, pursuant to (A)(ii) of this paragraph.

(i) The pit operator shall notify the appropriate Conservation Division District Office at least two (2) business days prior to field testing a soil liner for compaction to afford a Commission representative an opportunity to witness the field testing.

(ii) A minimum of six compaction tests shall be performed on any soil liner; a minimum of four widely spaced tests in the bottom of the pit and two tests on different slopes of the pit are required, unless otherwise directed by a Field Operations representative. Particular emphasis shall be placed on selecting locations for compaction tests where nonuniformity in soil texture or color can be observed.

(iii) Compaction tests shall be conducted in accordance with ASTM methods D-2922 or D-1556.

(iv) The soil materials of any liner shall be compacted to at least 90 percent of the Standard Proctor Density (ASTM D-698).

(7) **Geomembrane liners.**

(A) Any geomembrane liner that is installed in a reserve/circulation pit, spill prevention pit, or remediation pit, completion/fracture/workover pit, basic sediment pit, or recycling/reuse pit shall have a minimum thickness of 20-mil.

(B) Any geomembrane liner used in a noncommercial pit shall be chemically compatible with the type of substances to be contained and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include seams, and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit or anchored in an equivalent manner approved by the appropriate Conservation Division District Office.

(8) **Certification of liner.** The operator of any noncommercial pit that is constructed with a soil or geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner (e.g., permeability and compaction test results, bentonite receipts, and geomembrane liner specifications from the manufacturer), and shall make them available at all times for review by any representative of the Conservation Division.

(d) **Operation and maintenance requirements.**

(1) **Freeboard.** The fluid level of any noncommercial pit shall be maintained at all times at least 24 inches below the lowest elevation on the top of the berm.

(2) **Reserve/circulation pits.** The operator of any reserve/ circulation pit shall limit its contents to the fluids and cuttings from a single well unless authorized by the District Manager.

(3) **Off-site reserve pits.** A waterproof sign shall be posted within 25 feet of any off-site reserve pit and shall bear the name of the operator, legal description to the quarter quarter quarter section, permit number, and emergency telephone number.

(4) **Recycling/reuse pits.**

(A) Any pit permitted for drilling mud recycling or reuse may contain the fluids and cuttings from multiple wells, provided that those wells are operated by the pit operator.

(B) A waterproof sign shall be posted within 25 feet of any recycling/reuse pit and shall bear the name of the operator, legal description to the quarter quarter quarter section, permit number, and emergency telephone number.

(5) **Prevention of pollution.**

(A) All noncommercial pits shall be constructed, used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a noncommercial pit, sufficient measures shall be taken by the operator to stop or control the loss of contents, and reporting procedures pursuant to 165:10-7-5(c) shall be followed. Any materials lost from a pit shall be cleaned up as directed by any Field Operations representative. For a willful non-permitted discharge from a noncommercial pit, the operator may be fined up to $2,000.00.

(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil be removed or the surface area covered by the oil be protected from access to birds. [See Advisory Notice 165:10-7-3(c)].

(e) **Closure requirements.**

(1) **Designation of disposal method.** The operator of any reserve/ circulation pit shall indicate the proposed method of disposal of drilling fluids and/or cuttings on Form 1000 as required by 165:10-3-1(f). Options shall be limited to the following, unless written approval is granted by a District Manager or Field Inspector Supervisor:

(A) Evaporation/dewatering and backfilling.

(B) Chemical solidification of pit contents.

(C) Annular injection (requires permit).

(D) Land application (requires permit).

(E) Disposal in permitted commercial pit.

(F) Disposal at permitted commercial soil farming facility.

(G) Disposal at permitted recycling/reuse facility.

(2) **Trenching.**

(A) Before trenching, stirring or otherwise disturbing the bottom of any noncommercial pit, the pit shall be completely dewatered.

(B) Trenching, stirring, or other similar practice shall be prohibited for any lined pit.

(3) **Lined pits.**

(A) When closing any noncommercial pit with a soil or geomembrane liner, extreme care shall be taken to preserve the integrity of the liner.

(B) For any lined reserve/circulation pit, completion/fracture/ workover pit, recycling/reuse pit, or basic sediment pit, all free liquids shall be removed or chemically solidified with nonhazardous material.

(C) For any lined oil-based reserve/circulation pit, all cuttings or other materials remaining in the pit shall be chemically solidified with nonhazardous material.

(D) Soil cover, pursuant to (5) of this subsection, shall follow.

(4) **Soil cover.** Closure procedures for any noncommercial pit shall include a minimum of three feet of soil cover over any remaining pit contents, with all stockpiled topsoil being applied last. The materials shall be mounded or sloped to encourage runoff. A variance from this provision may be granted by the appropriate Conservation Division District Office for justifiable cause. A written request and supporting documentation is required. The appropriate Conservation Division District Office shall respond in writing within five business days either approving or disapproving the request.

(5) **Erosion control.** Any noncommercial pit shall be closed in such a manner that any future erosion will not cause the discharge of the pit contents. This may require vegetative cover and/or a diversion terrace(s).

(6) **Notification to appropriate Conservation Division District Office.** The operator of any noncommercial pit shall notify the appropriate Field Inspector or appropriate Conservation Division District Office at least 48 hours prior to commencing closure, and for reserve/circulation pits shall advise if the disposal method is different from that indicated on Form 1000. The operator shall also notify the Field Inspector or appropriate Conservation Division District Office within 48 hours after reclamation of the site has been completed.

(7) **Time limits.** Any noncommercial pit shall be closed within the time limits set forth in this paragraph. Any extension of time for pit closure must be requested by the operator, who shall file an application pursuant to OAC 165:5-7-33. A legal change of operator of any noncommercial pit shall not extend the time limit for closure. If a noncommercial pit is converted from one type of use to another, the last use shall determine the time limit for closure.

(A) Any Category 1A, 1B or 2 reserve/circulation pit, either on-site or off-site, shall be closed within twelve months after drilling operations cease.

(B) Any Category 3 reserve/circulation pit, either on-site or off-site, shall be closed within six months after drilling operations cease.

(C) Any Category 4 pit shall have closure procedures commenced within 30 days and completed within 90 days after drilling operations cease.

(D) **Completion/fracture/workover pits.**

(i) Any reserve/circulation pit converted to a completion/fracture/workover pit shall be closed within six (6) months after drilling operations cease. Upon request by the operator, a six (6) month extension shall be granted by the Conservation Division, after review by a field inspector to confirm the pit is in compliance with 165:10-7-16 (c) and (d) requirements.

(ii) Any completion/fracture/workover pit not converted from a reserve/circulation pit shall be closed within 60 days after completion, fracture, or workover operations cease.

(E) Any emergency pit shall be emptied of its contents as soon as possible and closed within 60 days after the emergency situation ceases to exist.

(F) Any flare pit shall be closed within 30 days of abandonment of a lease.

(G) Any spill containment pit shall be closed within 30 days of abandonment of a lease.

(H) Any basic sediment pit shall be closed within 60 days after use of the pit ceases.

(I) Any recycling/reuse pit shall be closed within twelve months after operations cease.

(J) Any remediation pit shall be closed immediately after receipt of all contaminated materials.

(8) For failure to comply with any closure requirement, the operator may be fined up to $1,000.00.

(9) **Waiver of closure requirements.** Exemption from closure and transfer of responsibility for any noncommercial pit to the surface owner or other party shall be requested by filing an application pursuant to OAC 165:5-7-34. No approval shall be granted unless the analyses of the fluids show that the following ranges or concentrations are not exceeded:

(A) pH - 6.0-9.5 s.u.

(B) Chlorides - 3500 mg/l

(C) Total Dissolved Solids (TDS) or Total Soluble Salts (TSS)- 7000 mg mg/l

(D) Chromium (Total) - 10 mg/l

(E) Arsenic - 20 mg/l

(f) **Flow back water pits with capacity in excess of 50,000 barrels.**

(1) **Scope:** This subsection shall cover the permitting, construction, operation, and closure requirements for any noncommercial pit with a capacity in excess of 50,000 barrels used for the temporary storage of flow back water that is to be reused for hydraulic fracturing of wells. Such pits may be located either onsite or offsite of a well drilling location. Pits used to store only fresh water for fracturing of wells are addressed in OAC 165:10-7-16(b)(4). The permitting, construction, operation, and closure requirements for any noncommercial pit with a capacity of 50,000 barrels or less used for temporary storage of flow back water that is to be reused for hydraulic fracturing of wells are addressed in OAC 165:10-7-16(a)-(e).

(2) **Application.**

Prior to constructing any pit, the pit operator shall obtain a permit from the Manager of Field Operations or a Commission order authorizing the pit. For use of a pit without a permit or Commission order, the pit operator may be fined up to $5,000.00. Application for a pit permit shall be submitted to the Field Operations Department on Form 1014F.

(3) **Application requirements.** The pit operator shall attach to the Form 1014F two complete sets of documents in support of the application, which documents shall include, but not be limited to, the following:

(A) Written permission from the surface owner allowing a pit to be constructed and used on the subject tract.

(B) A lithologic log of test borings, identifying the subsurface materials encountered and the depth at which groundwater was encountered pursuant to (5)(A)(v) of this subsection.

(C) A topographic map of the pit site.

(D) The appropriate Soil Conservation Service (SCS) soil survey aerial photo and legend.

(E) A detailed drawing of the site, with complete construction plans drawn to scale by or under the supervision of a registered professional engineer.

(F) A plan for closure of the pit which shall provide for a minimum three feet of soil cover and shall specifically state how all aspects of closure shall be accomplished, including volume and fate of liquids, earthwork to close the pit (including placement of stockpiled topsoil), and revegetation of the site.

(G) An itemization of projected hauling, closure, reclamation, maintenance, and monitoring costs.

(H) A plan for post-closure maintenance and monitoring which shall address maintenance of the site as well as monitoring and plugging of wells. Exemption from the plugging of monitor wells may be obtained upon written request and approval of the Manager of Pollution Abatement.

(I) A plan for operation which shall address the method(s) by which excess water will be disposed.

(4) **Notice.**

(A) **Notice of application.** Notice of the application for a permit for a pit with a capacity in excess of 100,000 barrels shall be published one time in a newspaper of general circulation in Oklahoma County, Oklahoma, and in a newspaper of general circulation published in each county in which the subject lands are located. The notice shall include the following information:

(i) The name, physical mailing address, telephone number, electronic mail address and facsimile number of the applicant or its representative, whom anyone may contact for additional information concerning the application.

(ii) The location of the proposed pit to the nearest 40 acre tract.

(iii) The capacity of the proposed pit.

(iv) The type of fluids to be stored in the proposed pit.

(v) The notice must also include the following language:

(I) Written protests to the relief sought must be submitted to the applicant or its representative and to the Manager of the Field Operations Department, Oklahoma Corporation Commission, P.O. Box 52000, Oklahoma City, OK, 73152-2000, within fifteen (15) days after publication of the notice. Written protests must specify the name of the applicant, location of the proposed pit, reasons for protest, and the name(s), physical mailing address(es), telephone number(s), electronic mail address(es) and facsimile number(s) of the protestant(s).

(II) If there are no written protests to the application and the Commission does not require a hearing, the application shall be presented to the Manager of the Field Operations Department for administrative review without a hearing, and if the application is protested, then any protestants shall receive notice of hearing.

(B) **Proof of notice.** The applicant shall submit affidavit(s) of publication to the Field Operations Department to show compliance with the requirements of subparagraph (4)(A) above.

(C) **Procedure.**

(i) If a written protest to the application is submitted to the Field Operations Department within fifteen (15) days after the date the notice of application is published, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof given in the same manner required in the filing of an application on the Pollution Docket.

(ii) If no written protest is submitted to the Field Operations Department and the Commission does not require a hearing, the application shall be presented to the Manager of the Field Operations Department for administrative review.

(5) **Construction requirements.**

(A) **Site limitations.**

(i) Any pit that is to be constructed or operated in an area covered by a field or area rule shall be subject to the more stringent requirements of either this subsection or the field or area rule.

(ii) No pit shall be constructed or used unless an investigation of the soils, topography, geology, and hydrology conclusively shows that storage of flow back water at the site will not be harmful to groundwater, surface water, soils, plants, or animals in the surrounding area. No pit shall be constructed or used on or in an abandoned mine, strip pit, quarry, canyon, or streambed.

(iii) No pit shall be constructed or used on any site that is located within a 100-year flood plain.

(iv) No pit shall be constructed or used within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 USC Section 300h-7, Safe Drinking Water Act), or within

one mile of a public water well for which the WPA has not been delineated.

(v) No pit shall be constructed unless it can be shown that there will be a minimum of 25 feet between the bottom of the pit and the groundwater level. To ascertain this and to demonstrate the subsurface profile of the site, a minimum of three test borings (the exact number of locations to be determined by the Pollution Abatement Department) shall be drilled to a minimum depth of 25 feet below the proposed bottom of the pit and into the first free water encountered. Perched water tables are not considered for the purposes of this unit. Test borings need not extend deeper than 50 feet below the bottom of the pit if free water has not been encountered before that depth. All boreholes converted to monitor wells shall conform to (6)(A) of this subsection. All boreholes not converted to monitor wells shall be plugged from top to bottom with bentonite, cement, and/or other method approved by the Pollution Abatement Department within 30 days of drilling completion.

(B) **Runoff water prohibited.** No runoff water from surrounding land surfaces shall be allowed to enter a pit.

(C) **Stockpiling of topsoil.** Prior to constructing a pit, all topsoil within the top twelve inches of soil at the site shall be stockpiled for use as the final cover at the time of closure. The topsoil may be stockpiled in the outside slopes of the berms, provided it is not used for structural purposes and is readily distinguishable from other soil materials at the time of closure.

(D) **Maximum fluid depth.** Any pit shall be constructed to contain a maximum fluid depth as authorized by the Manager of Field Operations on the Form 1014F, or in the Commission order authorizing the pit. A minimum freeboard of three feet shall be maintained.

(E) **Maximum authorized volume.** The maximum authorized volume allowed to be stored in a pit shall be calculated from three (3) feet below the point of the lowest elevation of the top of the berm wall.

(F) **Width of the crown.** The crown (top) of any berm shall be a minimum eight feet in width.

(G) **Slopes.** The inside slope of any exterior berm of the pit shall not be steeper than 3:1 (horizontal to vertical) and the outside slope of the pit shall not be steeper than 2.5:1.

(H) **Earthwork compaction.** All earthwork shall be compacted to achieve a minimum 90% Standard Proctor Density and shall be applied in lifts where some method of bonding is achieved between lifts, with each lift not to exceed eight inches prior to compaction.

(I) **Unique design requirements.** For pits that may require special construction considerations, variances may be granted by the Manager of Field Operations or by Commission order if the proposed design meets or exceeds the requirements appearing in this subsection.

(J) **Geomembrane liners.**

(i) Pits permitted under this subsection must contain a geomembrane liner. The geomembrane liner must have a minimum thickness of ~~30~~40 mil.

(ii) The geomembrane liner shall be chemically compatible with the type of substances to be contained in the pit and shall have ultraviolet light protection sufficient to withstand the time the pit is to remain open.

(iii) The geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects. The pit operator shall notify the appropriate Conservation Division District Office at least two (2) business days prior to installation of the liner in the pit to afford a Commission representative an opportunity to inspect the site prior to the liner being installed. If a

Commission representative has not inspected the pit site within two (2) business days following notification, the pit operator may proceed to install the liner in the pit.

(iv) The geomembrane liner shall be continuous, although it may include welded or extruded seams, and it must cover the bottom and interior sides of the pit entirely. Sewing of seams is prohibited. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(K) **Fluid level marker.** A minimum of one stationary fluid level marker shall be erected in each pit. The marker shall be erected in a location within the pit where it can be easily observed. The marker shall be of such design that the maximum fluid level at any time may be clearly identified. Details of the proposed marker installation shall be approved by the Manager of Field Operations prior to installation.

(L) **Hydrologically sensitive areas.** If the proposed pit is to be located over a hydrologically sensitive area, in addition to the foregoing construction requirements, the following additional requirements shall apply:

(i) A minimum 40-mil geomembrane liner, double-lined, with a leachate collection system between the liners shall be required.

(ii) The Manager of Pollution Abatement shall determine the minimum depth of all monitor wells.

(6) **Monitor wells and leachate collection systems.**

(A) A minimum of three monitor wells-one (1) upgradient and two (2) downgradient from the pit-shall be installed. The exact number and location of the monitor wells shall be approved by the Manager of Pollution Abatement prior to installation. Additional monitor wells may be required for pits constructed in the general vicinity of public water supply wells, well head protection areas and hydrologically sensitive areas. No monitor well shall be installed more than 250 feet from the toe of the outside berm of the pit, nor shall any existing water well be used as a monitor well unless approved by the Manager of Pollution Abatement. All new monitor wells shall be drilled to a depth of at least ten feet below the top of the first free water encountered, and all monitor wells shall be drilled to a depth of at least ten feet below the base of the pit. All new monitor wells shall be drilled and completed by a licensed monitor well driller. If documentation is submitted to the Manager of Pollution Abatement prior to drilling the monitor wells to show that no free water will be encountered within 50 feet below the bottom of the pit, the Manager of Pollution Abatement may give approval for the wells to be drilled to a lesser depth. All new monitor wells shall meet the requirements set out in rules established by the Oklahoma Water Resources Board, in addition to the following requirements:

(i) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(ii) Within 30 days of installation, specific completion information, a diagram of the locations and numerical labeling for all monitor wells shall be submitted to the Manager of Pollution Abatement.

(B) Leachate collection system: The pit operator may elect to install a leachate collection system in lieu of monitor wells, if such system will adequately detect any leak from the pit. The plan for the leachate collection system must accompany the Form 1014 and such plan must be approved by the Manager of Pollution Abatement prior to installation of the leachate collection system.

(7) **Monitor well and leachate collection system sampling.** The pit operator shall sample the monitor wells or leachate collection system prior

to placing any fluids other than fresh water in the pit. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours prior to sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the pit operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) If requested by a representative of the Conservation Division, a sufficient portion of each sample (approximately one (1) pint) shall be properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(D) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(E) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. The Manager of Field Operations may require samples to be analyzed for additional constituents.

(F) A copy of each analysis and a statement as to the depth to groundwater encountered in each well or leachate collection system, or a written statement that no water was encountered, shall be forwarded to the appropriate Conservation Division District Office within 30 days of sampling.

(G) The pit operator is required to conduct sampling every six months after the date pit operations commence and for a minimum of one year after closure is completed. The Manager of Field Operations may require sampling on a more frequent basis.

(8) **Liner certification.** An affidavit signed by the person who was responsible for installing the pit liner, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules, shall be submitted to the Manager of Field Operations before operation of the pit commences. Supporting documentation shall also be submitted, such as geomembrane liner specifications from the manufacturer, if requested by the District Manager.

(9) **Pit approval.** The pit operator shall notify the appropriate Conservation Division District Office at least two (2) business days prior to commencing pit operations to afford a Commission representative an opportunity to inspect the site. If a Commission representative has not inspected the pit site within two (2) business days following notification, the operator may commence pit operations, provided the affidavit and any supporting documentation referred to above has been submitted to the District Manager.

(10) **Operation and maintenance requirements.**

(A) **Vegetative cover.** Vegetative cover shall be established on all areas of earthfill on the outside slope of the pit immediately after pit construction or during the first planting season following the construction of the pit if the pit construction is completed out of season. The cover shall be sufficient to protect those areas from soil erosion and shall be maintained. The Manager of Field Operations may approve alternative erosion control measures if the alternative method meets or exceeds the vegetative cover requirement.

(B) **Fencing.** The pit shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence.

(C) **Sign.** A waterproof sign bearing the name of the pit operator, legal description, and emergency telephone number shall be posted within 25 feet of the pit and shall be readily visible.

(D) **Site security.** All sites shall be secured by a locked gate. Fluids shall be placed in a pit only when representative(s) designated by the operator are present at the site if trucks are to be used in the

operation. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(E) **Acceptable materials.** No operator of a flow back water pit shall place any substances in the pit other than flow back water or additional fresh water if required for hydraulic fracturing operations. The pit may receive flow back water from additional wells as long as the company authorized on the Form 1014F or in a Commission order operates or is a working interest owner in the additional wells. Another operator may use the pit on a temporary basis if the pit operator submits to and obtains the Commission's approval of an amended Form 1014F permitting such temporary use. If the pit is in compliance with this Section, the Manager of Field Operations may approve the amended Form 1014F administratively without additional notice and hearing. If the Manager of Field Operations determines conditions have changed since the issuance of the permit, then the Manager of Field Operations may request that the operator seeking approval to use the pit on a temporary basis obtain the issuance of a Commission order authorizing the operator's use of the pit after application, notice and hearing.

(F) **Oil film.**

(i) The flow back water pit shall not contain an oil film.

(ii) The protection of migratory birds shall be the responsibility of the pit operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil films be removed as soon as possible from the pit or that the surface of the pit be protected from access to birds. [See Advisory Notice in OAC 165:10-7-3(c)].

(G) **Aesthetics.** All pit sites shall be maintained so that there is no junk iron or cable, oil or chemical drums, paint cans, domestic trash, or debris on the premises.

(H) **Structural integrity.** All pits shall be used, operated, and maintained at all times so as to prevent the escape of their contents. All erosion, cracking, sloughing, settling, animal burrows, or other condition that threatens the structural stability of any earthfill shall be repaired immediately upon discovery.

(I) **Time period for operation.** The period of time during which the pit is to remain in operation shall be specified on the approved Form 1014F or Commission order.

(11) **Prevention of pollution.** All flow back water pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a non-permitted discharge, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in OAC 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division. For a willful non-permitted discharge, the pit operator may be fined up to $5,000.00.

(12) **Closure requirements.**

(A) **Notification.** The Manager of Field Operations shall be notified in writing whenever the pit becomes inactive, or operation of the pit ceases for any reason.

(B) **Time limit.** Closure shall be commenced within 60 days and completed within one year of when the pit becomes inactive or cessation of operations. In cases where extenuating circumstances exist, one extension of six (6) months may be administratively approved in writing by the Manager of Field Operations. The pit operator must file an application and notice of hearing pursuant to OAC 165:5-7-1 et seq. and obtain the issuance of a Commission order concerning any additional request for an extension of time for pit closure.

(C) **Trenching.** Trenching, stirring or other similar practice shall be prohibited with respect to the pit.

(D) **Preserving integrity of liner.** Extreme care shall be taken to preserve the integrity of the liner when closing the pit. All fluids

shall be removed from the pit when closing the pit. Once fluids have been removed from the pit, the liner may be folded and closed in place.

(E) **Soil cover.** A minimum of three feet of soil cover shall be placed over the pit, with all stockpiled topsoil being applied last. The soil cover shall be mounded or sloped to encourage runoff and so as to prevent erosion. The Manager of Field Operations may require the pit operator to establish a vegetative cover over the pit. The pit operator can request a variance to these requirements by submitting a written request and supporting documentation to the Manager of Field Operations. The Manager of Field Operations shall respond in writing within five (5) business days after receipt of a request for a variance to the requirements in this subsection from the pit operator.

(F) **Notification to appropriate Conservation Division District Office.** The pit operator shall notify the appropriate Field Inspector or appropriate Conservation Division District Office at least 48 hours prior to commencing closure. The pit operator shall also notify the Field Inspector or appropriate Conservation Division District Office within 48 hours after reclamation of the site has been completed.

(G) **Penalty for failure to comply with closure requirements.** A pit operator failing to comply with the closure requirements set out in this subsection may be fined up to $1,000.00.

(H) **Post closure monitoring.** The pit operator is required to sample the monitor wells or leachate collection system at the site for a minimum of one year after closure of the pit is completed, and the pit operator must comply with the sampling and reporting requirements appearing in OAC 165:10-7-16(f)(7), above. Variances to the post closure monitoring and reporting requirements may be granted in writing by the Manager of Field Operations if an approved leachate collection system has been employed at the site and if additional hydrogeologic data which demonstrates the pit has not leaked is submitted to and accepted by the Manager of Field Operations.

(13) **Surety requirements.**

(A) **Agreement with Commission.** The operator of a flow back water pit shall file with the Manager of Document Handling for the Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the pit or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(B) **Surety amount and type.** The Manager of Field Operations shall establish the amount of surety for the authority to construct and/or operate the pit. The amount of surety shall be based on factors such as dimensions of the pit and costs of hauling, closure, reclamation, and monitoring. The amount may be subject to change for good cause. Upon approved closure of a pit, the Manager of Field Operations may reduce the surety requirement to an amount which would cover the cost of monitoring the site and plugging the monitor wells. Surety shall be maintained for as long as monitoring is required. The type of surety shall be a corporate surety bond, certificate of deposit, or irrevocable letter of credit. Any type of surety that expires shall be renewed prior to 30 days before the expiration date.

(14) **Application to existing pits.** Operators of pits permitted prior to the effective date of this subsection must either comply with parts (f)(6)(monitor wells and leachate collection systems), (f)(7)(monitor well and leachate collection system sampling) and (f)(13)(surety requirements) or close such pits within one (1) year of the effective date of this

subsection. Operators of pits permitted prior to the effective date of this subsection must also comply with parts (f)(5)(K) (fluid level marker), (f)(10)(operation and maintenance requirements), (f)(11) (prevention of pollution) and (f)(12)(closure requirements). All pits permitted but not yet constructed as of the effective date of this subsection shall also be subject to the construction requirements in part (f)(5).

(15) **Variances.** Except as otherwise provided in this subsection, variances from provisions of this subsection may be granted for good cause by order after application, notice, and hearing.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 16 Ok Reg 2230, eff 7-1-99 (RM 980000035); Amended at 23 Ok Reg 2229, eff 7-1-06 (RM 200600012); Amended at 24 Ok Reg 1796 (RM 200700004), eff 7-1-2007; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-17. Surface discharge of fluids

(a) **Scope.** This Section shall cover the surface discharge of hydrostatic test water, storm water from diked areas, and produced water from tanks or other containment vessels.

(b) **Discharge of hydrostatic test water.**

(1) Hydrostatic test water used in the testing of new pipeline segments, new casing, new tubing, new tanks and new vessels, may be discharged as necessary without a permit, notification to the Commission, or adherence to any other provisions of this Section, provided the following conditions are met:

(A) **Low chlorides.** Chloride concentration does not exceed 1000 mg/l.

(B) **Sheen.** There shall be no visible sheen or discoloration as a result of testing; however, certain dyes used to establish mechanical integrity may be approved.

(C) **Notice to appropriate Conservation Division District Office.** Any discharges exceeding 1,000 barrels shall require notification to the appropriate Conservation Division District Office.

(2) Hydrostatic test water used in the testing of existing tanks, vessel lines and transmission pipelines may be discharged upon notification to the Oklahoma Corporation Commission appropriate Conservation Division District Office on Form 1014HD provided that the following conditions are met:

(A) **Oil and grease.** The oil and grease content of the discharge water shall not exceed 15 mg/l.

(B) **Sheen.** There shall be no visible sheen or discoloration as a result of testing; however, certain dyes used to establish mechanical integrity may be approved.

(C) **Total Suspended Solids.** The Total Suspended Solids shall not exceed 45 mg/l.

(D) **pH.** The pH shall not be less than 6.5 nor exceed 9 s.u.

(E) **Foreign material.** The discharge must be free from foreign material such as welding scrap tank sediments or sand blasting waste material.

(F) **Soil erosion.** Standard soil erosion prevention procedures shall be required.

(3) Hydrostatic test water that meets the requirements listed in (b) (2) of this Section may be discharged in volumes less than 15 bbls without filing Form 1014HD.

(4) Hydrostatic test water that will be discharged to land and not directly into waters of the state and which may exceed the discharge parameters specified in (b)(2), shall be discharged only upon submission

and approval by the Pollution Abatement Department of a plan for one-time discharge.

(5) Hydrostatic test water not covered under (b)(1) from transmission lines and tanks that contain waste products that are listed as hazardous waste under the Resource Conservation and Recovery Act and have not been cleaned or pigged must meet the following discharge requirements in addition to (b)(2) of this Section:

(A) The following parameters may not be exceeded: Benzene, .028 MG/L; toluene, .3 MG/L; phenol, .250 MG/L.

(B) EPA analytical method 8020 shall be used unless approved by the Manager of Pollution Abatement.

(c) **Discharge of storm water.** Storm water accumulations in any diked area built for the containment of tank battery spills may be discharged as necessary without a permit, notification to the Commission, or adherence to any other provisions of this Section, provided the following conditions are met:

(1) **No hydrocarbons.** A visual inspection of the storm water is made and there is no sheen or other visible evidence of hydrocarbons being present.

(2) **Low chlorides.** Chloride concentration does not exceed 1000 mg/l.

(3) **Conditions recorded.** The operator records the conditions required by (1) and (2) in this subsection for each discharge, maintains those records for a period of three (3) years, and makes them available upon request to any representative of the Field Operations Department.

(d) **Discharge of produced water.**

(1) **Site restrictions.** Discharge of produced water shall only occur on land having an Exchangeable Sodium Percentage (ESP) no greater than 15, pursuant to (f)(3) of this Section, and all of the following characteristics as determined by the appropriate Soil Conservation District or by a qualified soils expert:

(A) A maximum slope of five percent.

(B) Depth to bedrock at least 20 inches.

(C) Slight salinity (defined as electrical conductivity less than 4,000 micromhos/cm) in the topsoil or upper six inches of the soil.

(D) A water table deeper than six feet from the soil surface, except a perched water table.

(E) A minimum distance of 100 feet from any stream designated by Oklahoma Water Quality Standards (available for viewing at the Commission's Oklahoma City Office and appropriate Conservation Division District Offices) or any fresh water pond, lake, or wetland (designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service and available for viewing at the Commission's Oklahoma City Office).

(2) **Water quality limitations.** A surface discharge permit shall not be issued if the produced water to be discharged exceeds either of the following concentrations:

(A) Total Dissolved Solids (TDS) or Total Soluble Salts (TSS) - 5000 mg/l.

(B) Oil and Grease - 1000 mg/l.

(e) **Sampling requirements.**

(1) **Contact with appropriate Conservation Division District Office.** The appropriate Conservation Division District Office shall be contacted at least two business days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and produced water to be discharged. A variance from this provision may be granted by the appropriate Conservation Division District Office for justifiable cause. A written request and supporting documentation shall be required. The appropriate Conservation Division District Office shall respond in writing within five working days after receipt, either approving or disapproving the request.

(2) **Produced water.** Produced water to be discharged shall be sampled using the following procedure, unless exempt pursuant to (f)(4) of this Section.

(A) Prior to sampling, fresh water shall not be added to any tank or other containment vessel for dilution or any other purpose.

(B) A sample of the produced water to be discharged shall be taken from the bottom of the tank or other containment vessel. A minimum two quart sample shall be placed into a foil or teflon covered, glass container. The container shall be filled completely to exclude air and delivered to the laboratory within seven days. No samples shall be altered in any way.

(C) Another sample of the produced water to be discharged (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector, unless exempt by the District Manager.

(3) **Receiving soil.** Soil samples shall be taken from the proposed discharge area and analyzed, unless exempt pursuant to (f)(4) of this Section. A minimum of 20 representative surface core samples (0-6 inches) must be taken from each sample area, combined and thoroughly mixed, then a minimum one pint composite sample taken and placed in a clean container for delivery to the lab. No sample area shall exceed 40 acres.

(f) **Analysis requirements.**

(1) **Certified laboratory.** The samples of soil and produced water shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Department of Environmental Quality or in the North American Proficiency Testing System, unless exempt pursuant to (4) of this subsection.

(2) **Parameters for produced water.** Parameters for analysis of the produced water shall include, but not be limited to, Total Dissolved Solids (TDS) or Total Soluble Salts (TSS) and Oil and Grease.

(3) **Parameters for soil.** Parameters for analysis of the receiving soil shall include, but not be limited to, Electrical Conductivity or Total Soluble Salts (TSS) and Exchangeable Sodium Percentage (ESP).

(4) **Exemptions.** The appropriate Conservation Division District Office may exempt the analysis of produced water if an analysis of the produced water from a well located within one mile and producing from the same formation has been previously submitted. Analysis of the receiving soil may be exempt if an analysis of the same soil type(s) within one mile of the proposed discharge site has been previously submitted.

(g) **Application for permit.**

(1) **Permit required.** No person shall discharge produced water from a tank or other containment vessel without applying for and obtaining a permit issued under this subsection. An operator discharging produced water without a permit may be fined up to $1,000.00.

(2) **Who may apply.** Only the operator of the well associated with the tank or other containment vessel, the contents of which are sought to be discharged, may apply for a surface discharge permit.

(3) **Required form and attachments.** Each application for surface discharge of produced water shall be submitted to the appropriate Conservation Division District Office on Form 1014D in quadruplicate. The forms shall be properly completed and signed. Attached to at least one of the forms shall be the following:

(A) A copy of written notice to the surface owner that the applicant intends to discharge produced water as per 165:10-7-17 to a specific portion of real property as designated by legal description.

(B) If the operator has an agent, a contractual agreement between the parties or an affidavit designating the contractor or agent (Form 1014LA).

(C) A well prepared map or diagram, drawn to scale, showing the proposed and potential discharge areas.

(D) Site suitability report, pursuant to (d)(1) of this Section, provided by a qualified soils expert (include qualifications).

(E) Analysis of produced water, unless exempt pursuant to (f)(4) of this Section.

(F) Soil analysis, unless exempt pursuant to (f)(4) of this Section.

(G) Other information as required by this Section or requested by the appropriate Conservation Division District Office.

(4) **Review period.** The appropriate Conservation Division District Office shall review the application, either approve or disapprove it, and return a copy of Form 1014D within five business days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014D; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(h) **Maximum application rate.**

(1) **Soil loading standards.** The maximum application rate shall be calculated by the appropriate Conservation Division District Office using the following soil loading standards. (Soil loading standards are based upon standards set forth in "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook 60. Pub. U.S. Salinity Laboratory, Riverdale, California, 1954. "Critical Concentrations for Irrigation Water Supplies," Water Quality Criteria, 1972 Ecological Research Series, EPA R2-73033, March, 1973).

(A) Total Soluble Salts - 6,000 lbs/acre (less TSS in soil).

(B) Oil and Grease - 500 lbs/acre.

(2) **Determination of most limiting parameter.** The maximum application rate shall be restricted by the most limiting parameter. It may require more than one application to achieve the maximum application rate while avoiding runoff. The appropriate Conservation Division District Office shall indicate on the permit what the maximum application rate shall be after making the following calculations:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL SOLUBLE SALTS (TSS)

_____ppm TSS in soil[1] X 2 = _____lbs/ac TSS in soil

6000 lbs/ac TSS - _____ lbs/ac TSS in soil = Maximum TSS (lbs/ac) to be applied

Maximum TSS (lbs/ac) _____ ÷ (_____ ppm TSS in water[1] X .000001) = Maximum lbs/ac of water to be applied _____

Maximum lbs/ac _____ ÷ _____lbs/bbl[2] = Maximum bbls/ac _____

PROCEDURE FOR CALCULATING APPLICATION RATE OF OIL AND GREASE

500 lbs/ac ÷ (_____ppm in water X .000001) = Maximum lbs/ac of water to be applied _____

Maximum lbs/ac _____ ÷ _____ lbs/bbl[2] = Maximum bbls/ac _____

[1]Electrical Conductivity (EC expressed in micromhos/cm) may be used to estimate TSS: EC x 0.64 = ppm TSS.
[2]Based on documented weight of composite sample.

(i) **Conditions of permit.** Any discharge of produced water that is done under this Section shall be subject to the following conditions or stipulations of the permit.

(1) **Presence of representative.** A representative of the operator shall be on the discharge site at all times that water is being applied. A variance from this provision may be granted by the appropriate Conservation Division District Office for justifiable cause. A written request and supporting documentation shall be required. The appropriate Conservation Division District Office shall respond in writing within five business days after receipt, either approving or disapproving the request.

(2) **Weather restrictions.** Surface discharge shall not be done:

(A) During precipitation events or when precipitation is imminent.

(B) When the soil moisture content is at a level such that the soil would not readily take the addition of water.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of water cannot be accomplished or the buffer zones, pursuant to (3) of this subsection, cannot be maintained.

(3) **Buffer zones.** Surface discharge shall not be done within the following buffer zones:

(A) Fifty feet of a property line boundary.

(B) Fifty feet of any stream not designated by Oklahoma Water Quality Standards.

(C) Three hundred feet of any actively-producing water well used for domestic or irrigation purposes.

(D) Eight hundred feet of any public water well.

(4) **Application rate.** The maximum application rate of produced water stipulated by the permit shall not be exceeded. Application of produced water outside the approved plot shall be prohibited. Accurate records shall be kept as to the quantities discharged and the dates of each discharge.

(5) **Discharge method.** Discharge of produced water shall be uniform over the approved discharge plot and shall be made by spray irrigation or other method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(6) **Runoff or ponding prohibited.** No runoff or ponding of discharged water shall be allowed during application.

(7) **Annual report.** An annual report shall be submitted by April 1 of each year and shall be made on Form 1014P. Attached to the annual report shall be current (within three months) analyses of the produced water and soil from the discharge plot, pursuant to (8) of this subsection.

(8) **Additional testing.** The produced water shall be analyzed annually and the receiving soils shall be sampled and analyzed a minimum of every five (5) years, pursuant to (e)(1) through (e)(3) and (f)(1) through (f)(3) of this Section. When 75 percent of the maximum permitted application volume of TSS or Oil and Grease [(h) of this Section] has been applied or when the ESP exceeds 11, water and soil sampling shall be done quarterly or semiannually as determined by the appropriate Conservation Division District Office.

(9) **Expiration of permit.** The permit shall expire by its own terms when testing, pursuant to (8) of this subsection, indicates that the concentration of TSS or Oil and Grease in the water exceeds the limitations of (d)(2) of this Section, or more than 98 percent of the maximum application rate of TSS or Oil and Grease [(h) of this Section] has been applied or the ESP exceeds 15.

(10) **Violations.** If the applicant violates the conditions of the permit or this Section, the surface discharge shall be discontinued and the appropriate Conservation Division District Office shall be contacted immediately. The appropriate Conservation Division District Office may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, surface discharge may resume with Field Operations'

approval. If the permit is revoked, the operator may make application for a hearing to reinstate it.

(j) **Discharge from reserve pits.** Water accumulation in any reserve pit used for the containment of air drilling cuttings or water-based drilling fluids may be discharged to land provided a permit is obtained from the Commission. Any operator discharging without a permit may be fined $5,000.00.

(1) **Who may apply.** Only the operator of the well or the operator's designated agent may apply for the permit.

(2) **Required form and attachments.** Application for discharge of water to land shall be submitted to the appropriate Conservation Division District Office on Form 1014X. Attached to the application shall be the following:

(A) Written permission of the surface owner.

(B) A topographic map(s) with the location of the discharge area.

(C) Analysis of the water.

(D) Copies of all chain of custody forms.

(E) If there is an agent, a notarized affidavit designating the agent, signed by the operator (Form 1014LA).

(3) **Conditions of permit.**

(A) **Notice to field inspector.** The applicant shall notify the appropriate Conservation Division District Office at least 24 hours prior to discharge to allow a Commission representative an opportunity to be present.

(B) **Presence of representative.** A representative of the operator shall be on the discharge site at all times during discharge.

(C) **Condition of water.**

(i) Chloride content must not exceed 1,000 mg/l and TDS must not exceed 1,500 mg/l.

(ii) **Sheen.** There must be no visible sheen or discoloration as a result of drilling operations.

(iii) **pH.** The pH shall not be less than 6.5 nor exceed 9 standard units.

(D) **Foreign material.** The discharge shall be free of foreign material such as debris, sediments, and drilling mud solids.

(E) **Maximum slope.** A maximum slope of 5% if vehicles with a diffusion system are to be used; a maximum slope of 8% if a spray irrigation system is used.

(F) All discharge must be a minimum of 100 feet from any perennial stream, pond, lake or wetland and 50 feet from any intermittent stream. All land applications shall be a minimum of 50 feet from any property line.

(G) **Land application method.** The land application equipment must be approved by the Commission prior to use. The application method must not allow soil erosion to occur. If the irrigation method is to be used, the area must be terraced or appropriate erosion control methods shall be used. The integrity of the pit wall shall be maintained at all times to avoid the discharge of drilling mud solids.

(H) **Runoff prohibited.** No runoff shall be allowed. Ponding may be allowed as long as practices are in place that will not allow the water to run into creeks or drainage ways.

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; amended at 13 Ok Reg 2381, eff 7-1-96; Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 97000002); Amended at 23 Ok Reg 2229, eff 7-1-06 (RM 200600012); Amended at 24 Ok Reg 1784, eff 7-1-07 (RM 200700004); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-18. Discharge to surface waters

Discharge of deleterious substances to streams or other surface waters is prohibited except by order of the Commission; unless permitted by a valid National Pollutant Discharge Elimination System (NPDES) Permit issued by U.S. EPA.

165:10-7-19. Land application of water-based fluids from earthen pits, tanks and pipeline construction

(a) **Authority for land application.** No person shall land apply fluids except as provided by 165:10-9-2, 165:10-7-17, or this Section. Any operator failing to obtain a permit may be fined up to $2,000.

(b) **Scope.** This Section shall cover the land application of water-based drilling fluids and cuttings from earthen pits, tanks, or other containment structures; however, this Section shall not be exclusive of other authorities for land application listed in (a) of this Section. Any land application made under this Section shall be done from a single well, single pad (containing multiple wells), or pipeline construction location. Permits shall not be granted for lands that have been previously permitted and used for these practices or similar practices such as soil remediation within the last three (3) years.

(c) **Site suitability restrictions.** Land application shall only occur on land having all of the following characteristics below, as field verified by a soil scientist or other qualified person pre-approved by the Commission. Any variance from site suitability restrictions must be approved by the Oil and Gas Conservation Division (see (f)(2)(C) of this Section).

(1) **Maximum slope.** A maximum slope of eight percent for all application methods.

(2) **Depth to bedrock.** Depth to bedrock must be at least 20 inches.

(3) **Soil texture.** A soil profile (as defined by USDA soil surveys) containing at least twelve inches (may be cumulative) of one of the following soil textures between the surface and the water table, unless a documented impeding layer of shale is present: loam, silt loam, silt, sandy clay loam, silty clay loam, clay loam, sandy loam, fine sandy loam, sandy clay, silty clay, or clay.

(4) **Salinity.** Slight salinity [defined as Electrical Conductivity (EC) less than 4,000 micromhos/cm] in the topsoil, or upper six inches of the soil, and a calculated Exchangeable Sodium Percentage (ESP) less than 10.0.

(5) **Depth to water table.** No evidence of a seasonal water table within six (6) feet of the soil surface as verified by field observation and published data.

(6) **Distance from water bodies.** A minimum distance of 100 feet from the land application site boundary to any perennial stream and 50 feet to any intermittent stream shown on the appropriate United States Geological Survey (U.S.G.S.) topographic map (available for viewing at the Commission's Oklahoma City Office and appropriate Conservation Division District Offices) and a minimum of 100 feet to any freshwater pond, lake, or wetland. [Designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service, available for viewing at the Commission's Oklahoma City Office (also, see (h)(6) of this Section)].

(7) **Site specific concerns.** Void of slick spots within or adjacent to the land application area, where subsurface lateral movement of water is unlikely, or areas void of concentrated surface flow such as gullies or waterways.

(8) **Stockpiling of cuttings.** Stockpiling of cuttings may be used during the handling and transportation of the cuttings both at the well and pipeline construction location and the receiving site. At the well site or pad generating the waste or pipeline construction location the cuttings must be placed in a steel pit or the areas used for this practice must be lined and bermed if required by the appropriate Conservation Division District Office. A stockpile of cuttings at the receiving site must be located within the permitted area and the areas used for this practice must be lined and bermed if required by the appropriate Conservation Division District Office. The

stockpile of cuttings, whether at the well or pipeline construction location or the receiving site, must be closed within 30 days of cessation of drilling operations.

(d) **Sampling requirements.**

(1) **Notice to Field Inspector.** The appropriate Field Inspector shall be contacted at least two business days prior to sampling of the receiving soil and sampling of the drilling fluids and/or cuttings to be land applied from an earthen pit. This is to allow a Commission representative an opportunity to be present.

(2) **Receiving soil.** Sampling of the receiving soil shall be performed by, or under the supervision of, a soil scientist or other qualified person pre-approved by the Commission. Soil samples shall be taken from the proposed application area and analyzed. A minimum of four representative core samples from the surface (0-6 inches) must be taken from each ten acres, or part thereof. Each group of surface core samples representative of a ten-acre area (or less) shall be combined and thoroughly mixed. A minimum one-pint composite sample shall be taken and placed in a clean container for delivery to the laboratory. Alternatively, soil samples may be composited by the laboratory.

(3) **Drilling fluids and/or cuttings.**

(A) **Earthen pits.** Drilling fluids and/or cuttings to be land applied shall be sampled using the following procedure:

(i) Prior to sampling, fresh water (except natural precipitation) shall not be added to any pit for dilution or any other purpose.

(ii) A minimum of four samples, each from different quadrants of the pit and representative of the materials to be land applied, must be taken if the volume to be land applied is 25,000 bbls. or less. If more than 25,000 bbls. are to be land applied, a minimum of four quadrant samples plus one sample for each 5,000 bbls. over 25,000 bbls. will be required. The samples shall be combined and thoroughly mixed, then a minimum two quart composite sample placed into a foil or teflon covered glass container. The container shall be filled completely to exclude air and delivered to the laboratory within seven days. No samples shall be altered in any way.

(iii) After samples have been taken for analysis from a pit, the operator shall not allow the addition of fluids or other materials, except natural precipitation or fresh water to decrease the viscosity of the fluid.

(B) **Tanks.** Sampling of the drilling fluids and/or cuttings shall occur after the application has been approved. A minimum of one representative sample must be taken from each tank, the contents of which are to be land applied.

(e) **Analysis requirements.**

(1) **Testing.**

(A) The composite sample(s) of soil shall be tested by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Department of Environmental Quality or in the North American Proficiency Testing System. Either a 1:1 extract or saturated paste extract shall be used for sample preparation.

(B) Methods of analysis.

(i) **Earthen pits.** The composite sample(s) of drilling fluids and/or cuttings shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Department of Environmental Quality or in the North American Proficiency Testing System.

(ii) **Tanks.** Samples of the drilling fluids and/or cuttings may be tested on-site. A filter press shall be used for preparation of samples. Tests must be performed by a person who is knowledgeable and experienced in the chemical testing of fluids. Acceptable on-site testing protocol may be obtained from the appropriate Conservation Division District Office.

(2) **Parameters for receiving soil.** Parameters for analysis of the receiving soil shall include at a minimum EC and ESP.

(3) **Parameters for drilling fluids and/or cuttings.**

(A) **Earthen pits.** Parameters for analysis of the drilling fluids and/or cuttings shall include at a minimum EC and Oil and Grease (O&G). Dry Weight shall also be determined if a significant amount of solids will be land applied.

(B) **Tanks.** EC shall be a required parameter for analysis of drilling fluids and/or cuttings. Dry weight shall also be determined if a significant amount of solids will be land applied.

(f) **Application for permit.**

(1) **Who may apply.** Only the operator of a well or pipeline or the operator's designated agent may apply for a land application permit under this Section, except that a commercial pit operator may also apply in case of emergency or for the purpose of facilitating repair or closure.

(2) **Required form and attachments.** Each application for land application of drilling fluids and/or cuttings shall be submitted to the Pollution Abatement Department on Form 1014S. A legible original shall be required. The following shall be attached to the application:

(A) Written permission from the surface owner to allow the applicant to land apply drilling fluids and/or cuttings. For purposes of obtaining such consent, the applicant shall use Form 1014L.

(B) A topographic map and the most recent aerial photograph (minimum scale 1:660) with the proposed and potential land application areas delineated as well as the location of cultural features such as buildings, water wells, etc. Both the topographic map and aerial photograph must show all areas within 1,320 feet of the boundary of the land application area.

(C) A site suitability report, pursuant to subsections (c) and (h)(6) of this Section, based on an on-site investigation and signed by a soil scientist or other qualified person. The report shall include detailed information concerning the site and shall discuss how all site characteristics were determined. Any requests for a variance to site suitability restrictions must be accompanied by a written justification that has been developed or approved by a soil scientist or other qualified person. The justification shall provide explanation as to safeguards which will assure that conditions of the permit will be met and there will be no adverse impacts from the land application.

(D) Analysis of drilling fluids and/or cuttings (for earthen pits only).

(E) Analyses of soil samples.

(F) Loading calculations.

(G) Copies of all chains-of-custody related to sampling.

(H) Manufacturer, model number, and specifications of testing equipment to be used (for tanks only).

(I) If there is an agent, a notarized affidavit designating same, signed by the operator within the last twelve months (Form 1014LA).

(J) Identification of any soil farming permit that has been issued in the same quarter section within the last three years. This information is available in the OCC Soil Farming Database on the web at www.occeweb.com.

(K) Other information as required by this Section or requested by the Pollution Abatement Department.

(3) **Review period.** The Pollution Abatement Department shall review the application, either approve or disapprove it, and return a copy of Form 1014S within five business days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014S; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(g) **Calculating maximum application rate.**

(1) **Earthen pits.**

(A) The maximum application rate shall be calculated by the applicant or the applicant's designated agent based on the analyses of the pit materials

and the soil of the application area. The averaging of TDS or TSS values of soil sampling areas shall not be permitted. If the entire application area is larger than ten acres, requiring separate soil sampling areas, the applicant or the applicant's designated agent shall use the highest soil TDS or TSS value of any sampling area in calculating the maximum application rate for the entire application area, and shall also calculate the maximum application rate of each ten acre (or less) application area using the respective TDS or TSS values of each soil sampling area. The applicant or the applicant's designated agent shall decide which of the two loading rates to use and notify the appropriate Conservation Division District Office when notification of commencement of land application is given, pursuant to (h)(1) of this Section.

(B) Soil loading formulas contained in Appendix I shall be used.

(C) The maximum application rate shall be restricted by the most limiting parameter. The Pollution Abatement Department shall indicate on the permit the maximum application rate and the minimum acreage that must be used.

(2) **Tanks.**

(A) The applicant shall calculate the maximum application rate based on the analysis of each tank or other containment vessel to be land applied and the soil of the application area. The averaging of TDS or TSS values of soil sampling areas shall not be permitted. If the entire application area is larger than ten acres, requiring separate soil sampling areas, the applicant shall have the option of using the highest soil TDS or TSS value of any sampling area in calculating the maximum application rate for the entire application area, or calculating the maximum application rate of each ten-acre (or less) application area using the respective TDS or TSS value of each soil sampling area.

(B) Soil loading formulas contained in Appendix I shall be used.

(C) Based on the maximum application rate, the applicant or its designated agent shall determine where the fluids will be applied and supervise the land application process.

(h) **Conditions of permit.** Any land application which is performed under this Section shall be subject to the following conditions or stipulations of the permit:

(1) **Notice to Field Inspector.** The applicant shall notify the appropriate Field Inspector at least 24 hours prior to the commencement of land application to allow a Commission representative an opportunity to be present.

(2) **Compliance agreement.** Any person responsible for supervision of land application shall have signed a compliance agreement with the Commission (Form 1014CA).

(3) **Presence of representative.** A representative of the applicant shall be on the land application site at all times during which fluids and/or cuttings are being applied. The representative shall be an employee of the applicant, designated agent, contractor, or other person pre-approved by the Commission.

(4) **Materials to be land applied.** Land application shall be limited to water-based drilling fluids and/or cuttings.

(5) **Weather restrictions.** Land application, including incorporation, shall not be done:

(A) During precipitation events.

(B) When the soil moisture content is at a level such that the soil cannot readily take the addition of drilling fluids.

(C) When the ground is frozen to a degree that the soil cannot readily take the addition of fluids.

(D) By spray irrigation when the wind velocity is such that even distribution of materials cannot be accomplished or the buffer zones, pursuant to (6) of this subsection, cannot be maintained.

(6) **Buffer zones.** Land application shall not be done within the following buffer zones, as identified in the site suitability report:

(A) Fifty feet of a property line boundary.

(B) Three hundred feet of any water well or water supply lake used for domestic or irrigation purposes.

(C) One-quarter (1/4) mile of any public water well or public water supply lake.

(7) **Land application rate.** The maximum calculated application rate of drilling fluids and/or cuttings shall not be exceeded. It may require more than one pass to achieve the maximum application rate while avoiding runoff or ponding, pursuant to (9) of this subsection. Application of drilling fluids and/or cuttings outside the approved plot shall be prohibited.

(8) **Land application method.**

(A) Application of drilling fluids and/or cuttings shall be uniform over the approved land application plot, shall not be applied at a rate to cause permanent vegetation damage, and shall be made by a method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(B) For earthen pits, if more than 500 lbs/acre of Oil and Grease or 50,000 lbs/acre of Dry Weight materials are applied, the materials shall be incorporated into the soil by use of the injection method, or by disking or some other method approved by the Commission.

(C) All land application vehicles shall be either a single or double axle vehicle with a permanently attached tank that shall not exceed 100 barrels, and the vehicle shall be equipped so as to minimize pooling and ruts caused by tire tracks. It shall have a diffuser mechanism to spread the mud/fluids in a fan pattern. Spreader bars shall not be used. The mud/fluids shall be forced from the tank with air pressure or a mechanical pump. Gravity applications are prohibited. Transport/tanker trucks (18 wheel vehicles) shall not be used for land application at any time. Use of an unauthorized vehicle or equipment may result in the revocation of the land application permit. A fine of up to $2,000.00 may be assessed for each violation of this paragraph.

(D) Drill cuttings shall be spread with an industrial mechanical spreader capable of broadcasting and/or fanning out the cuttings. Dozers, backhoes, motor blades or scrapers shall not be used to spread drill cuttings or drill solids during land application at any time.

(9) **Runoff or ponding prohibited.** No runoff of land applied materials shall be allowed during application. Ponding is prohibited, except where the flood irrigation method is approved. In order to comply with this rule, some applications will require the use of more than the minimum calculated acreage and/or a drying period between applications.

(10) **Vegetative cover.** If the vegetative cover is destroyed or significantly damaged by disking, injection, or other practice associated with land application, a bona fide effort shall be made to restore or reestablish the vegetative cover within 180 days after the land application is completed. Additional efforts shall be made until the vegetative cover is fully restored or reestablished.

(11) **Time period.**

(A) **Earthen pits.** Land application shall be completed within 90 days from the date of the permit. At the end of the 90-day period, the permit shall expire by its own terms.

(B) **Tanks.** Land application shall be completed within 90 days after drilling ceases. At the end of the 90-day period, the permit shall expire by its own terms.

(12) **Post-application report.** A post-application report (Form 1014R) shall be submitted by the operator or the operator's agent to the Manager of the Pollution Abatement Department within 90 days of the completion of land application. One extension may be granted for a period of up to 90 days by the Manager of the Pollution Abatement Department. If approval is obtained to amend the permit to authorize land application of contaminated soils and petroleum hydrocarbon based cuttings, any extension of time for submission of the post-application report granted by the Manager of the Pollution Abatement

Department shall begin on the date the amended permit is approved. The report shall give specific details of the land application, including test results of materials applied and loading rate calculations (for tanks only), volumes of materials applied, and an aerial photograph (minimum scale 1:660) delineating the actual area where materials were applied. All applicable loading calculations from Appendix I of this Chapter shall be included in the Form 1014R. The report shall contain a statement certifying that the land application was done in accordance with the approved permit. Failure to timely submit a Form 1014R may result in the assessment of a fine of up to $500.00.

(13) **Violations.** If the applicant violates the conditions of the permit or this Section, the land application shall be discontinued and the Pollution Abatement Department shall be contacted immediately. The Pollution Abatement Department may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, land application may resume with the Pollution Abatement Department's approval. If the permit is revoked,` the operator may make application for a hearing to reinstate it.

(14) **Requirements to close pit.** Neither filing an application nor receiving a permit under this Section shall extend the time limit for closing a reserve pit pursuant to 165:10-7-16, or a commercial pit pursuant to 165:10-9-1.

(i) **Variances.** A variance from the time provisions of (d)(1), (h)(1), or (h)(10) of this Section may be granted by the appropriate Conservation Division District Office for justifiable cause. A written request and supporting documentation shall be required. The appropriate Conservation Division District Office shall respond in writing within five business days after receipt, either approving or disapproving the request.

[**SOURCE:** Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 97000002); Amended at 23 Ok Reg 2229, eff 7-1-06 (RM 200600012); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001; Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-20. Noncommercial disposal or enhanced recovery well pits used for temporary storage of saltwater

(a) **Scope.** This Section shall apply to any production operation where a pit is used for temporary storage of saltwater, except (c)(7) of this Section, which shall apply to any noncommercial well, regardless of whether or not a pit is used. Any pit sought to be approved pursuant to this Section will require a permit. The operator of the proposed pit shall submit Form 1014 to the appropriate Conservation Division District Office for review and approval.

(b) **Construction requirements.**

(1) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any noncommercial disposal well or enhanced recovery pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit, unless the pit is of such design that discharge directly into it presents no spill potential.

(2) **Pit specifications.** Except as provided by (4)(A) of this subsection, any noncommercial disposal or enhanced recovery well pit shall be constructed of concrete or steel or be lined with a geomembrane liner according to the following:

(A) Concrete pits must be steel reinforced and have a minimum wall thickness of six inches.

(B) Steel pits must have a minimum wall thickness of three-sixteenths (3/16) inch. A previously used steel pit may be installed, provided it is free of corrosion or other damage.

(C) Geomembrane liners must:

(i) Have a minimum thickness of 30 mils, be chemically compatible

with the type of wastes to be contained, and have ultraviolet light protection.

(ii) Be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(iii) Be continuous (may include seams) and cover the bottom and interior sides of the pit entirely. The edges must be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(3) **Certification of liner.** The operator of any saltwater storage pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(4) **Monitoring of site.**

(A) If not constructed according to one of the three methods in (2) of this subsection, any noncommercial disposal or enhanced recovery well pit shall be required to have a leachate collection system or at least one monitor well, unless it can be shown that the pit is not located over a hydrologically sensitive area. The District Manager may require more than one monitor well if he has reason to believe one would not be sufficient to adequately monitor the site.

(B) Any monitor well shall be installed within 100 feet of the pit. An existing nearby water well may be used as a monitor well upon written approval by the District Manager or Manager of Field Operations.

(C) Any new monitor well shall be drilled to a depth of at least ten feet below the top of the first free water encountered and shall be drilled and completed by a licensed monitor well driller. If documentation is submitted to the District Manager prior to drilling the monitor well to show that no free water will be encountered within a depth of 50 feet from the surface, the District Manager may allow the monitor well(s) to be drilled to a lesser depth or eliminated.

(D) Any new monitor well shall meet the requirements as set out in rules established by the Oklahoma Water Resources Board, in addition to the following requirements:

(i) A removable and lockable cap placed on top of the casing. The cap must remain locked at all times, except when a well is being sampled.

(ii) Within 30 days of installation, construction details for any leachate collection system or specific completion information for any monitor well and a diagram of the location of any monitor well in relation to the pit shall be submitted to the Manager of Field Operations.

(c) **Operation and maintenance requirements.**

(1) **Fencing.** All noncommercial disposal or enhanced recovery well surface facilities that have a pit shall be completely enclosed by a fence at least four feet in height. Said fence shall be constructed in such a manner as to prevent livestock from entering the pit area.

(2) **Site maintenance.** The normal access surface of any well site that has a pit, including the access road(s), shall be maintained in a condition that will safely and easily allow access.

(3) **Exclusion of runoff water.** No pit shall be allowed to receive runoff water.

(4) **Freeboard.** The fluid level in any concrete or steel noncommercial disposal or enhanced recovery well pit shall be maintained at all times at least six inches below the top of the pit wall. Any geomembrane lined pit shall have a minimum of 18 inches of freeboard at all times.

(5) **Temporary storage only.** No pit shall be used as permanent storage for salt water.

(6) **Sampling of monitor wells or leachate collection systems.**

(A) Sampling of monitor wells and leachate collection systems shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides (Cl) and total dissolved solids (TDS) by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required as determined by the District Manager or Manager of Field Operations. A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or a written statement that no water was encountered, shall be forwarded to the Manager of Field Operations, within 30 days of sampling.

(7) **Prevention of pollution.** All noncommercial disposal or enhanced recovery wells shall be maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from surface facilities, sufficient measures shall be taken immediately to stop, contain, and control the loss of materials. Reporting of said discharge shall be in compliance with 165:10-7-5(c). Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division of the Commission.

(8) **Oil film.** The operator of a saltwater pit shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all open top tanks and pits containing fluid be kept free of oil films or sludge or be protected from access to birds. [See Advisory Notice 165:10-7-3(c)]

(d) **Closure requirements.**

(1) **Time limit.** Within 180 days of the cessation of operations, all associated pits shall be emptied of all contents, and either removed or filled with soil. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within one (1) year.

(2) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(e) **Prospective application to existing facilities.** All provisions of this Section, except those in (b)(2) and (b)(3), shall apply to all existing pits within the scope of this Section which are, or have been, in operation prior to the effective date of this Section. Operators shall have one (1) year from the effective date of this Section in which to bring their facilities into compliance with the applicable provisions of this Section. Failure to comply with any applicable provision may result in revocation of the authority to operate.

(f) **Variances.**

(1) A variance from the time requirements of (c)(6), (d)(1), or (e) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and justifiable explanation is required. The District Manager or Manager of Field Operations shall respond in writing within five business days, either approving or disapproving the request.

(2) Any variance from the liner requirements as required under (b)(2) of this Section may be granted by the Manager of Field Operations after

receipt of a written request and supporting documentation required by the department.

[**SOURCE:** Amended in Rule Making 980000034, eff 7-1-99; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 Ok Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-7-21. Refining and processing of oil and gas

(a) All deleterious substances obtained or used in the processing and refining of oil and gas shall be disposed of in a manner that will prevent the pollution of fresh water.

(b) Chemicals, gasolines, oil, and other deleterious substances shall be stored, where necessary, in tanks or containers of a material and of a construction and in a manner that will prevent the escaping, seepage, or draining of such liquids into any fresh water.

165:10-7-22. Permits for County Commissioners to apply waste oil, waste oil residue, or crude oil contaminated soil to roads

(a) **Prohibition against application of waste oil, waste oil residue, or crude oil contaminated soil without permit.** This Section prohibits any Board of County Commissioners from applying waste oil, waste oil residue, or crude oil contaminated soil to a street or road without a permit.

(b) **Permit by appropriate Conservation Division District Office.** A District Manager for the Conservation Division may issue to a Board of County Commissioners for a county within the district a permit to apply waste oil, waste oil residue, or crude oil contaminated soil to a street or road within the county.

(c) **Permit requirements.**

(1) **Use of Form 1014W.** The application and permit to apply waste oil, waste oil residue, or crude oil contaminated soil shall be made on Form 1014W, which shall be submitted by electronic mail to the Manager of the appropriate Conservation Division District Office.

(2) **Telephone permits.** In case of emergency, a District Manager may issue a permit by telephone. If an applicant obtains a permit by telephone, then the applicant shall file Form 1014W and attachment within five business days after receipt of the permit by telephone.

(3) **Conditions for permit.**

(A) Waste oil, waste oil residue, and contaminated soils applied under this Section shall consist of crude oil and materials produced with crude oil only and shall not contain any refined oils such as motor oils, lubricants, compressor oils or hydraulic fluids.

(B) If required by the District Manager, a hydrocarbon analysis shall be submitted with Form 1014W. The analysis shall be performed by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma in accordance with OCC-approved methods.

(C) Waste oil, waste oil residue, and crude oil contaminated soil shall be applied in such a manner that pollution of surface or subsurface waters will not likely occur and public and private property adjoining the street or road will be protected.

(D) During operations for road oiling, all necessary signs, lights, and other safety and warning devices shall be used to alert road users to conditions. A sign shall be posted with the contractor or authority's name and phone number to contact in case of emergency.

(E) Following completion of the project there shall be a uniform soil/oil base (all liquid worked in), with no visible free-standing oil.

(F) Proper care shall be taken to avoid runoff of oil or water into borrow ditches or adjacent areas.

(G) No road oiling shall be conducted:

(i) When the temperature is less than 45° F.

(ii) In any area where water collects and stands.

(iii) Where soil moisture content or road conditions such as soil type, tight soil conditions, packed soil conditions, or grade limits prevent rapid absorption of the oil.

(d) **Notice to appropriate Conservation Division District Office.** The Board of County Commissioners receiving the permit shall notify the appropriate Conservation Division District Office at least two days prior to commencement of road oiling under a permit.

(e) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the road oiling operation to ensure compliance with this Section.

(f) **Duration of permit.** The permit shall state the duration of the permit, and it shall also state that if the application fails to comply with either the terms of the permit or the terms of this Section, then the permit shall terminate automatically.

(g) **Disapproval or cancellation of permits.**

(1) If a District Manager receives a complaint about a road oiling permit, he shall cause an investigation of the complaint to be made as soon as practicable. During the investigation, the District Manager may direct the applicant to cease road oiling under a permit. If necessary, the District Manager may verbally revoke the permit.

(2) If a District Manager disapproves an application or cancels a permit, the applicant may apply to the Commission for an order under OAC 165:5-7-41.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-23. Disposal of waste oil

(a) All waste oil and waste oil residue shall be disposed of in one of the following ways:

(1) Transfer or sale to a reclaimer or transporter.

(2) Transfer or sale to County Commissioners.

(3) Administrative approval from the Conservation Division.

(b) All operators or owners of pits, tanks, commercial disposal operations, or reclaimers shall maintain books and records describing the disposition of all waste oil or waste oil residue. A copy of the run or load ticket will satisfy this requirement if the information required in (c) of this Section is contained therein.

(c) The following information shall be contained in said books and records and subject to audit and inspection by representatives of the Commission for a minimum period of three years:

(1) The amount of waste oil or waste oil residue removed.

(2) The location of the waste oil or waste oil residue prior to disposal.

(3) The destination of waste oil or waste oil residue as reported by transporter.

(4) The name of the transporter of waste oil or waste oil residue.

165:10-7-24. Waste management practices reference chart

(a) **Scope.** This Section provides reference guidelines for the disposal of wastes under the jurisdiction of the Commission which are generated by oil and gas operators and pipeline companies. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(b) **Waste materials and disposal options.** Consistent with EPA's policy on source reduction, recycling, treatment and proper disposal, operators shall use waste management practices as listed in (c) of this Section which describes the various management practices for the following waste materials. For any of the following waste materials where option (16) of subsection (c) is listed, option (16) shall be considered before any other option.

(1) Produced water: Options 1, 7 & 9
(2) Weighted water: Options 1 & 7
(3) Used treatment fluids, frac sand, and other flowback wastes: Options 1, 2, 5 & 7 and, for frac sand only, options 3 & 20
(4) Water based mud: Options 1, 2, 5, 6, 7, 8 & 19
(5) Water based mud cuttings: Options 1, 2, 3, 4, 5, 6, 7, 8, 12 & 19
(6) Oil based mud: Options 1, 2, 3, 4, 5, 7, 12 & 22
(7) Oil based mud cuttings: Options 1, 2, 3, 4, 5, 7, 8, 12 & 14
(8) Crude oil: Options 1, 4, 12, 13 & 14
(9) Used motor, gear, lube, compressor and hydraulic oils: Options 1, 15 & 16
(10) Used solvents: Options 1, 15 & 16
(11) Oily debris: Options 1, 3, 13 & 20
(12) Filter media and backwash: Options 1, 3, 7, 15, 16 & 20
(13) Glycol, amine, and caustic wash: Options 1 & 7
(14) Iron sponge: Options 3 & 20
(15) Molecular sieve: Options 3 & 20
(16) Produced sand/sediment: Options 3, 7, 8, 17 & 20
(17) Tight emulsions: Options 1, 4, 8, 12, 14 & 17
(18) Unused treatment chemicals: Options 1, 15 & 16
(19) Tank bottoms from E&P: Options 1, 3, 4, 7, 8, 10, 12, 14 & 17
(20) Paraffin: Options 1, 3, 4, 12, 14, 15, 16 & 20
(21) Asbestos insulation: Options 3 & 15
(22) Non-asbestos insulation: Options 3, 15 & 20
(23) Used batteries: Options 1, 3, 15 & 16
(24) Oils containing PCBs: Option 11
(25) Oils not containing PCBs: Options 1, 15 & 16
(26) Empty oil and chemical drums: Options 1, 3 & 15
(27) Salt contaminated soils: Options 5, 6, 8 & 17
(28) Crude oil contaminated soils: Options 1, 3, 4, 8, 10, 12, 14, 17 & 22
(29) Pit sludges from wellsites, disposal well pits and gathering systems: Options 1, 3, 4, 7, 8, 12, 17 & 20
(30) Gathering line pigging wastes: Options 1, 3, 7 & 20
(31) Gas plant sweetening wastes: Options 1, 3, 7 & 20
(32) Gas plant dehydration wastes: Options 1, 3 & 7
(33) Cooling tower blowdown from gas plants: Options 7 & 15
(34) Wastes from subsurface natural gas storage: Options 1, 3, 7 & 20
(35) Wastes other than refined product removed from produced water and other well fluids prior to injection or disposal: Options 1, 7, 8, 17 & 20
(36) Gases removed from the production stream: Options 1, 7, 13 & 18
(37) Waste crude oil and light hydrocarbons (gas condensate) in reserve pits, other impoundments or tankage at wellsites: Options 1, 7, 8, 13 & 17
(38) Contaminated ground water (except refined products): Options 1, 7, 21 & 22
(39) Pipeline sludge and other deposits removed from pipe or equipment on E&P gathering systems: Options 1, 3, 7, 8, 10, 17 & 20
(40) Residues and truckwash from inside the tank of trucks used to transport saltwater, drilling mud or spent completion fluids: Options 1, 3, 7 & 20
(41) Sewage and wastes from portable toilets: Option 15
(42) Crude pipeline pigging wastes, contaminated soil and residue from transmission and trunk lines: Options 1, 3, 4, 8, 12, 15, 16, 17 & 22

(43) Water or soil contaminated by refined product from E&P operations: Options 1, 16, 21 & 22
(44) Rigwash and supply water: Options 1, 5, 7 & 8
(45) Storm water and hydrostatic test water from E&P operations: Options 1, 7, 9 & 22
(46) Spent filters: Options 1 & 3
(47) Trash and debris: Options 15 & 20
(48) Refined petroleum product releases: Options 1, 3, 8, 13, 16, 17 & 22
(49) Refined petroleum product pigging wastes: Options 1, 3, 8, 15, 16, 17 & 22
(50) Water or soil contaminated by refined products from pipelines: Options 1, 16, 21 & 22
(51) Hydrostatic test water from pipelines: Options 1, 9, 16 & 22
(52) Tank bottoms from crude pipeline facilities: Options 1, 3, 4, 8, 10, 12, 14, 16, 17 & 22
(53) Tank bottoms from refined product pipeline facilities: Options 1, 3, 14, 15, 16, 17 & 22
(54) Water based mud and cuttings associated with pipeline construction: Options 6 and 8 (165:10-7-19 only)

(c) **Disposal options and rule reference guide.** The following waste disposal options are referenced in (b) of this Section:
(1) Reclaim and/or recycle.
(2) Burial (in accordance with 165:10-7-16).
(3) Landfills regulated by the Oklahoma Department of Environmental Quality.
(4) Road applications by County Commissioners (in accordance with 165:10-7-22 and 165:10-7-28).
(5) Noncommercial pits (in accordance with 165:10-7-16).
(6) Commercial mud disposal pits (in accordance with 165:10-9-1).
(7) Underground injection (in accordance with 165:10-5-1 through 165:10-5-14).
(8) Land application (in accordance with 165:10-7-19 and 165:10-7-26).
(9) Discharge (in accordance with 165:10-7-17).
(10) Reclaim and/or recycle (in accordance with 165:10-7-23).
(11) In accordance with EPA; Code of Federal Regulations (CFR), Title 40, Part 761.60 through 761.79.
(12) Application to lease roads, well locations, and production sites (in accordance with 165:10-7-27 and 165:10-7-29).
(13) Open burning in accordance with Oklahoma Department of Environmental Quality regulations.
(14) Disposal of waste oil as specified in 165:10-7-23.
(15) Disposal in accordance with Oklahoma Department of Environmental Quality regulations.
(16) If the waste is determined to be a hazardous waste under the Federal Resource Conservation and Recovery Act (RCRA), disposal will be determined by the Oklahoma Department of Environmental Quality; if a non-hazardous waste, Option 17 may be used or other disposal option as approved by the Commission.
(17) On-site or in-situ bioremediation/remediation.
(18) Flaring or venting (in accordance with 165:10-3-15).
(19) Commercial soil farming (in accordance with 165:10-9-2).
(20) Burial as approved by the Commission.
(21) Surface discharge as approved by the Commission.
(22) Land application as approved by the Commission.

[**Source:** Amended at 12 Ok Reg 2039, eff 7-1-95; Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 97000002); Amended at 19 Ok Reg 1947, eff 7-1-02 (RM 200200017); Amended at 25 Ok Reg 2187, eff 7-11-08 (RM 200800003); Amended at 29 Ok Reg 950, eff 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001)]

165:10-7-25. One-time land application of water-based fluids from tanks or other containment vessels [REVOKED]

[SOURCE: Amended at 9 Ok Reg 2295, eff 6-25-92; Revoked in Rule Making 97000002, eff 7-1-97]

165:10-7-26. Land application of contaminated soils and petroleum hydrocarbon based drill cuttings

(a) **Authority for land application.** No person shall land apply soils or drill cuttings contaminated by salt or petroleum hydrocarbons except as provided by this Section. Any operator failing to obtain a permit may be fined up to $2,000.00.

(b) **Scope.** This Section shall cover the land application of soils and drill cuttings contaminated by salt and/or petroleum hydrocarbons. Petroleum hydrocarbon-contaminated soils land applied under this Section shall meet the RCRA criteria for exempt or non-exempt/nonhazardous waste. [Reference 40 CFR Subtitle C and EPA publication EPA530-K-95-003 "Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulation]. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality. Any land application made under this Section shall be done from a single well or a single pad (containing multiple wells). Permits shall not be granted for lands that have been previously permitted and used for this practice or similar practices such as soil remediation within the last three (3) years.

(c) **Receiving site suitability restrictions.** Land application shall only occur on land having all of the characteristics below, as field verified by a soil scientist or other qualified person pre-approved by the Commission. Any variance from site suitability restrictions must be approved by the Oil and Gas Conservation Division (see (g)(2)(C) of this Section).

(1) **Maximum slope.** A maximum slope of eight percent for all application methods.

(2) **Depth to bedrock.** Depth to bedrock will be at least 20 inches if crude oil contaminated soils or petroleum hydrocarbon-based drill cuttings are to be applied; 20 inches if salt contaminated soils are to be applied.

(3) **Soil texture.** A soil profile (as defined by USDA soil surveys) containing at least twelve inches (may be cumulative) of one of the following soil textures between the surface and the water table, unless a documented impeding layer of shale is present: loam, silt loam, silt, sandy clay loam, silty clay loam, clay loam, sandy loam, fine sandy loam, sandy clay, silty clay, or clay.

(4) **Salinity.** Slight salinity [defined as Electrical Conductivity (EC) less than 4,000 micromhos/cm] in the topsoil, or upper six inches of the soil, and a calculated Exchangeable Sodium Percentage (ESP) less than 10.0.

(5) **Depth to water table.** No evidence of a seasonal water table within six (6) feet of the soil surface as verified by field observation and published data.

(6) **Distance from water bodies.** A minimum distance of 100 feet from the land application site boundary to any perennial stream and 50 feet to any intermittent stream found on the appropriate United States Geological Survey (U.S.G.S.) topographic map (available for viewing at the Commission's Oklahoma City Office and appropriate Conservation Division District Offices); and a minimum of 100 feet to any freshwater pond, lake, or wetland designated by the National Wetlands Inventory Map Series, prepared by the U.S. Fish and Wildlife Service (available for viewing at the Commission's Oklahoma City Office). Also, see (h)(6) of this Section.

(7) **Site specific concerns.** Void of slick spots within or adjacent to the land application area, where subsurface lateral movement of water is

unlikely, or areas void of concentrated surface flow such as gullies or waterways.

(8) **Stockpiling of cuttings.** Stockpiling of cuttings may be used during the handling and transportation of the cuttings both at the well location and the receiving site. At the well site or pad generating the waste, the cuttings must be placed in a steel pit or the areas used for this practice must be lined and bermed if required by the appropriate Conservation Division District Office. A stockpile of cuttings at the receiving site must be located on the permitted area. The stockpile of cuttings, whether at the well location or the receiving site, must be closed within 30 days of cessation of drilling operations.

(d) **Sampling requirements.**

(1) **Notice to Field Inspector.** The appropriate Field Inspectors shall be contacted at least two business days prior to sampling of the receiving soil and materials to be land applied. This is to allow a Commission representative an opportunity to be present.

(2) **Receiving soil.** Sampling of the receiving soil shall be performed by, or under the supervision of, a soil scientist or other qualified person pre-approved by the Commission. Soil samples shall be taken from the proposed application area and analyzed. A minimum of four representative surface core samples from the surface (0-6 inches) must be taken from each ten acres, or part thereof. Each group of surface core samples representative of a ten-acre area (or less) shall be combined and thoroughly mixed. A minimum one pint composite sample shall be taken and placed in a clean container for delivery to the laboratory. Alternatively, soil samples may be composited by the laboratory.

(3) **Materials to be land applied.** Representative samples of the materials to be land applied shall be taken, composited into a minimum one-pint sample, and placed in a clean container for delivery to the laboratory. Alternatively, materials to be land applied may be composited by the laboratory.

(e) **Analysis requirements.**

(1) **Salt contaminated soils or drill cuttings.** Analysis requirements will be dependent upon the loading method that is chosen. For most applications, loading based on Total Dissolved Solids (TDS) or Total Soluble Salts (TSS) will be most appropriate. However, applicants proposing to land apply on a site in western Oklahoma, where the soils commonly contain moderate to high levels of gypsum, may benefit from using the loading formula based on Chlorides (Cl).

(A) Samples of soil and materials to be land applied shall be tested by a laboratory proficient in testing soils. Either a 1:1 extract or saturated paste extract shall be used for sample preparation for TDS or TSS or Cl loading. A saturated paste moisture equivalent is necessary where the saturated paste sample preparation method is used.

(B) Parameters for analysis of the receiving soil shall include at a minimum EC, TDS or TSS, and ESP for TDS/TSS loading. For Chloride loading, parameters shall include Chlorides (dry weight basis) and ESP.

(C) Parameters for analysis of soils or drill cuttings contaminated by salt shall include at a minimum EC for TDS/TSS loading and both EC and Cl for Chloride loading.

(2) **Soils and drill cuttings contaminated by petroleum hydrocarbons.**

(A) Samples of soil and materials to be land applied shall be tested by a laboratory proficient in testing soils.

(B) Parameters for analysis of the receiving soil shall include at a minimum EC and ESP.

(C) Parameters for analysis of soils or drill cuttings contaminated by petroleum hydrocarbons shall include at a minimum a test of the appropriate carbon range(s), which is determined by the nature of the waste material. These include Gasoline Range Organics (GRO) - C6 to C10 (EPA test method 8015/8020 M) and TPH (Oklahoma method 1005 extended C35).

(f) **Application rates.**

(1) **Calculations.** The maximum application rate for TDS or TSS, Cl, and GRO, or TPH shall be calculated by the applicant based upon the analyses of the materials to be land applied and the soil of the application area. For salt contaminated soils or drill cuttings, if the application area encompasses more than one soil sampling area, the rate shall be calculated in one of two ways, depending on how the application will be made. The applicant may either calculate the maximum application rate for the entire application area based upon the highest soil TDS or TSS or Cl value of any sampling area (averaging not allowed), or calculate it for each ten acre (or less) application area using the respective soil TDS or TSS or Cl values of each sampling area.

(2) **Soil loading formulas.** The maximum application rate for any application area shall be restricted by the most limiting parameter. To determine this, the soil loading formulas in Appendix I of this Chapter shall be used as applicable.

(3) **Variances.** In special situations, a request for a variance relating to soil loading of petroleum hydrocarbons may be administratively approved by the Manager of the Pollution Abatement Department. The applicant shall submit a written request explaining the circumstances or conditions which warrant a variance and shall also submit a management plan for reducing the petroleum hydrocarbon content in the soil to two percent or less.

(g) **Application for permit.**

(1) **Who may apply.** Only the operator responsible for generating the waste to be land applied or the operator's designated agent may apply for a land application permit, except that the Oklahoma Energy Resources Board or its designated contractor may make application to land apply materials for which there is no responsible party.

(2) **Required form and attachments.** Each application for land application of soils contaminated by salt and/or crude oil or petroleum hydrocarbon-containing deleterious substances shall be submitted to the Pollution Abatement Department on Form 1014S. A legible original shall be required. The following shall be attached to the application:

(A) Written permission from the surface owner to allow the applicant to land apply, incorporate, and fertilize materials. For purposes of obtaining such consent, the applicant shall use Form 1014L.

(B) A topographic map and the most recent aerial photograph (minimum scale 1:660) with the proposed and potential land application areas delineated as well as the location of cultural features such as buildings, water wells, etc. Both the topographic map and aerial photograph must show all areas within 1320 feet of the boundary of the land application area.

(C) Receiving site suitability report, pursuant to subsections (c) and (h)(6) of this Section, based on an on-site investigation and signed by a soil scientist or other qualified person. The report shall include detailed information concerning the site and shall discuss how all site characteristics were determined. Any requests for a variance to site suitability restrictions must be accompanied by a written justification that has been developed or approved by a soil scientist or other qualified person. The justification shall provide explanation as to safeguards which will assure that conditions of the permit will be met and there will be no adverse impacts from the land application.

(D) Analyses of receiving soil samples.

(E) Analyses of contaminated soil or petroleum hydrocarbon-based drill cuttings.

(F) For contaminated soils, an investigation report and diagram, drawn to scale, detailing the aerial extent and depth of the contamination; and sampling procedures which were used to assure that representative samples were taken.

(G) Loading calculations.

(H) Copies of all chains-of-custody related to sampling.

(I) If there is an agent, a notarized affidavit designating same, signed by the operator within the last 12 months (Form 1014LA).

(J) Identification of any soil farming permit that has been issued in the same quarter section within the last three (3) years. This information is available in the OCC Soil Farming Database on the web at www.occeweb.com.

(K) Other information as required by this Section or requested by the Pollution Abatement Department.

(3) **Review period.** The Pollution Abatement Department shall review the application, either approve or disapprove it, and return a copy of Form 1014S within five business days of submission of all required or requested information. If approved, a permit number shall be assigned to Form 1014S; if disapproved, the reason(s) shall be given. The applicant may make application for a hearing if it is not approved.

(h) **Conditions of permit.** Any land application which is performed under this Section shall be subject to the following conditions or stipulations of the permit:

(1) **Notice to Field Inspector.** The applicant shall notify the appropriate Field Inspector at least 24 hours prior to the commencement of land application to allow a Commission representative an opportunity to be present.

(2) **Compliance agreement.** Any person responsible for supervision of land application shall have signed a compliance agreement with the Commission (Form 1014CA).

(3) **Presence of representative.** A representative of the applicant shall be on the land application site at all times during which materials are being applied. The representative shall be an employee of the applicant, designated agent, contractor, or other person pre-approved by the Commission.

(4) **Materials to be land applied.** Land application under this Section shall be limited to soils and drill cuttings contaminated by salt and/or petroleum hydrocarbons. Petroleum hydrocarbon-contaminated soils or drill cuttings land applied under this Section shall meet the RCRA criteria for exempt or non-exempt/nonhazardous waste. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(5) **Weather restrictions.** Land application, including incorporation, shall not be done:

(A) During precipitation events.

(B) When the soil moisture content is at a level such that the soil cannot readily take the addition of materials.

(C) When the ground is frozen to a degree that the soil cannot readily take the addition of fluids.

(6) **Buffer zones.** Land application shall not be done within the following buffer zones, as identified in the site suitability report:

(A) Fifty feet of a property line boundary.

(B) Three hundred feet of any water well or water supply lake used for domestic or irrigation purposes.

(C) One-quarter (1/4) mile of any public water well or public water supply lake.

(7) **Land application rate.** The maximum calculated application rate of materials shall not be exceeded. Under no circumstances shall land applied materials exceed a two inch depth. Furthermore, no runoff or ponding of land applied materials shall be allowed. It may require more than one pass or lift to achieve the maximum application rate while avoiding runoff or ponding. For land applications involving petroleum hydrocarbons all free oil shall be removed.

(8) **Land application method.**

(A) Application of materials shall be uniform over the approved land application area, and shall be made by a method approved by the Commission prior to use. Land applied materials shall be incorporated into the soil by disking or chiseling during or immediately after application to a

minimum depth of two times the depth of applied materials; however, if any contaminated sandy soil is applied to any clayey soil, incorporation shall be to a minimum depth of four times the depth of the applied materials. Tillage of grassland may not be necessary. If materials are land applied on grassland a reduced application rate may be necessary.

(B) All land application vehicles shall be either a single or double axle vehicle with a permanently attached tank that shall not exceed 100 barrels, and the vehicle shall be equipped so as to minimize pooling and ruts caused by tire tracks. It shall have a diffuser mechanism to spread the materials in a fan pattern. Spreader bars shall not be used. The materials shall be forced from the tank with air pressure or a mechanical pump. Gravity applications are prohibited. Transport/tanker trucks (18 wheel vehicles) shall not be used for land application at any time. Use of an unauthorized vehicle or equipment may result in the revocation of the land application permit. A fine of up to $2,000.00 may be assessed for each violation of this paragraph.

(C) The materials shall be spread with an industrial mechanical spreader capable of broadcasting and/or fanning out the cuttings. Dozers, backhoes, motor blades or scrapers shall not be used to spread materials during land application at any time.

(9) **Fertilizer.** For any land application involving petroleum hydrocarbon-contaminated soils and/or drill cuttings, if it is determined that revegetation is needed, fertilizer shall be applied at an appropriate rate as indicated by soil testing for available N-P-K to adjust the average carbon-nitrogen ratio in order to enhance biodegradation of the petroleum hydrocarbons and assist in reestablishing vegetation. Soil tests shall also include at a minimum EC, ESP, N-P-K, C:N ratio and TPH. Soil samples shall be collected from the affected area at a depth of six (6) inches. Background samples shall be collected from an adjacent unaffected area. In the absence of soil testing, Nitrogen, Phosphorus, and Potassium shall be applied at a rate of 160-40-40 lbs. per acre (actual N-P-K). Application of fertilizers shall be done in a manner that minimizes runoff potential (split applications) and so as to increase availability of nutrients to microorganisms for degradation of petroleum hydrocarbons.

(10) **Vegetative cover.** A bona fide effort shall be made to restore or reestablish the vegetative cover within 180 days after the land application is completed. Additional efforts shall be made until the vegetative cover is fully restored or reestablished.

(11) **Time period.**

(A) Land application shall be completed within 90 days of the anticipated completion date shown on the approved application form.

(B) At the end of the 90-day period the permit shall expire by its own terms.

(12) **Post-application report.** A post-application report (Form 1014R) shall be submitted by the operator or the operator's agent to the Manager of the Pollution Abatement Department within 90 days of the completion of land application. One extension may be granted for a period of up to 90 days by the Manager of the Pollution Abatement Department. If approval is obtained to amend a permit to land apply water-based fluids so as to authorize land application of contaminated soils and petroleum hydrocarbon based cuttings, any extension of time for submission of the post-application report granted by the Manager of the Pollution Abatement Department shall begin on the date the amended permit is approved. The report shall give specific details of the land application, including volumes of materials applied and an aerial photograph (minimum scale 1:660) delineating the actual area where materials were applied. All applicable loading calculations from Appendix I of this Chapter shall be included in the Form 1014R. The report shall contain a statement certifying that the land application was done in accordance with the approved permit. Failure to timely submit a Form 1014R may result in the assessment of a fine of up to $500.00.

(13) **Violations.** If the applicant violates the conditions of the permit or this Section, the land application shall be discontinued and the Pollution Abatement Department shall be contacted immediately. The Pollution Abatement Department may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, land application may resume with approval of the Pollution Abatement Department. If the permit is revoked, the operator may make application for a hearing to reinstate it.

(i) **Variances.** A variance from the time provisions of (d)(1), (h)(1), or (h)(10) of this Section may be granted by the appropriate Conservation Division District Office for justifiable cause. A written request and supporting documentation shall be required. The appropriate Conservation Division District Office shall respond in writing within five business days after receipt, either approving or disapproving the request.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2039, eff 7-1-95; Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 97000002); Amended at 23 Ok Reg 2229, eff 7-1-06 (RM 200600012); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-27. Application of waste oil, waste oil residue, or crude oil contaminated soil by oil and gas operators and pipeline companies

(a) **Scope.** This Section shall cover the application of waste oil, waste oil residue, or crude oil contaminated soil by oil and gas operators and pipeline companies to lease roads, pipeline service and tank farm roads, well locations, and production sites. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(b) **Permit by appropriate Conservation Division District Office.** A District Manager for the Conservation Division may issue to an oil or gas operator or pipeline company within the District a permit for road application of waste oil, waste oil residue, or crude oil contaminated soil to lease roads, pipeline service and tank farm roads, well locations, and production sites within the District. This subsection prohibits any operator from applying waste oil, waste oil residue, or crude oil contaminated soil without a permit. Any operator or pipeline company violating this subsection may be fined up to $2,000.00.

(c) **Permit requirements.**

(1) **Use of Form 1014X.** The application to apply waste oil, waste oil residue, or crude oil contaminated soil shall be made on Form 1014X, which shall be submitted by electronic mail to the Manager of the appropriate Conservation Division District Office.

(2) **Landowner permission.** Attached to the application shall be written permission by the surface owner to allow the operator or pipeline company to apply waste oil, waste oil residue, or crude oil contaminated soil as per this Section to a specific portion of real property as designated by legal description.

(3) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If an operator or pipeline company obtains a permit by telephone, the operator or pipeline company shall file Form 1014X and attachments within five business days after receipt of the permit by telephone.

(4) **Conditions for permits.**

(A) Waste oil, waste oil residue, and contaminated soils applied under this Section shall consist of crude oil and materials produced with crude oil only. Hazardous waste as defined at 40 CFR 261.3 is regulated by the Oklahoma Department of Environmental Quality.

(B) If required by the District Manager, a hydrocarbon analysis shall be submitted with Form 1014X. The analysis shall be performed by a

laboratory that is operated by the State of Oklahoma or certified by the Oklahoma Department of Environmental Quality in accordance with OCC-approved methods.

(C) Waste oil, waste oil residue, and crude oil contaminated soil shall be applied in such a manner that pollution of surface or subsurface waters will not likely occur and public and private property adjoining the application area will be protected.

(D) During application, any necessary signs, lights and other safety and warning devices shall be used as traffic requires to alert users to conditions. A sign shall be posted with the contractor's or operator's name and phone number to contact in case of an emergency.

(E) No application shall be conducted:

(i) When the temperature is less than 45° F.

(ii) In any area where water collects and stands.

(iii) Where conditions such as grade, soil moisture content, soil type, tight soil conditions, or packed soil conditions cause runoff or prevent rapid absorption of the oil.

(F) Following completion of the project, there shall be a uniform soil/oil base (all liquids worked in), with no visible free-standing oil.

(G) Proper care shall be taken to avoid runoff of oil into borrow ditches or adjacent areas.

(d) **Notice to Field Inspector.** The operator or pipeline company receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of application.

(e) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.

(f) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the operator or pipeline company fails to comply with either the terms of the permit or this Section, the District Manager may direct the operator or pipeline company to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the operator or pipeline company to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[**Source:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended at 12 Ok Reg 2017, eff 7-1-95; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-28. Application of freshwater drill cuttings by County Commissioners

(a) **Scope.** This Section shall cover the one-time application of freshwater drill cuttings by a Board of County Commissioners to a street or road.

(b) **Permits by District Office.** A District Manager for the Conservation Division may issue to any Board of County Commissioners within the District a permit for road application of freshwater drill cuttings to a street or road within the county. This Section prohibits any Board of County Commissioners from applying freshwater drill cuttings without a permit.

(c) **Site restrictions.** Application of freshwater drill cuttings shall only occur on sites having an:

(1) Electrical Conductivity (EC) no greater than 6,000 micromhos/cm; and

(2) Exchangeable Sodium Percentage (ESP) less than 15.0.

(d) **Sampling requirements.**

(1) The appropriate Field Inspector shall be contacted at least two business days prior to sampling to allow a Commission representative an

opportunity to witness the sampling of the receiving soil and freshwater drill cuttings to be applied.

(2) The receiving soil shall be sampled using the following procedure:

(A) A minimum of five samples shall be taken for each one-half (1/2) mile section of road (or borrow ditch) and composited into one sample for analysis.

(B) Sampling shall be to a minimum depth of six inches.

(3) The freshwater cuttings shall be sampled by taking a minimum of one representative sample for every five cubic yards of freshwater cuttings to be applied and composited into one quart sample for analysis.

(e) **Analysis requirements.**

(1) The composite samples of soil and drill cuttings shall be analyzed by a laboratory which tests soils.

(2) The parameters for the receiving soil shall include ESP and either EC or Total Dissolved Solids (TDS) or Total Soluble Salts (TSS).

(3) The parameters for the drill cuttings shall include TDS or Total Soluble Salts (TSS).

(f) **Maximum application rate.**

(1) The maximum application rate shall be calculated by the Board of County Commissioners using the following formula:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL DISSOLVED SOLIDS (TDS) OR TOTAL SOLUBLE SALTS (TSS)

_____ ppm TDS or TSS in receiving soil x 2 = _____ lbs/ac TDS or TSS in receiving soil.

10,000 lbs/ac TDS or TSS - _____ lbs/ac TDS or TSS in receiving soil = Maximum TDS or TSS (lbs/ac) to be applied _____.

Maximum TDS or TSS__(lbs/ac) to be applied _____ ÷ (_____ ppm TDS or TSS in cuttings x .000001) = Maximum lbs/ac of cuttings to be applied _____.

Actual weight of drill cuttings _____ lbs/cu ft x 27 = _____ lbs/cu yd.

Maximum lbs/ac to be applied _____ ÷ _____ lbs/cu yd = _____ cu yds/ac to be applied.

Total volume _____ cu yds ÷ _____ cu yds/ac = Minimum acres required _____.

(2) Calculations shall be submitted with the application.

(g) **Permit requirements.**

(1) **Use of Form 1014W.** The application to apply freshwater drill cuttings shall be made on Form 1014W, which shall be submitted by electronic mail to the Manager of the appropriate Conservation Division District Office.

(2) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If any Board of County Commissioners obtains a permit by telephone, the applicant shall file Form 1014W within five business days after receipt of the permit by telephone.

(3) **Conditions for permits.**

(A) The method to be used for application of freshwater drill cuttings shall not pollute surface or subsurface waters and shall protect public and private property adjoining the application area.

(B) During application, any necessary signs, lights and other safety and warning devices shall be used to alert users to conditions. A sign shall be posted with the contractor's or authority's name to contact in case of an emergency.

(C) All free liquids shall be removed before cuttings are applied.

(D) Following completion of the project, there shall be a uniform soil/cuttings base.

(h) **Notice to Field Inspector.** The Board of County Commissioners receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of the application.

(i) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.

(j) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the Board of County Commissioners fails to comply with either the terms of the permit or this Section, the District Manager may direct the Board of County Commissioners to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the Board of County Commissioners to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[SOURCE: Amended in Rule Making 200600012, eff 7-1-2006; Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-29. Application of freshwater drill cuttings by oil and gas operators

(a) **Scope.** This Section shall cover the one-time application of freshwater drill cuttings by oil and gas operators to private access areas, well locations, and production sites.

(b) **Permits by appropriate Conservation Division District Office.** A District Manager for the Conservation Division may issue to an operator within the District a permit for application of freshwater drill cuttings to private access areas, well locations, and production sites within the District. This Section prohibits any operator from applying freshwater drill cuttings without a permit. Any operator violating this subsection may be fined up to $2,000.00.

(c) **Site restrictions.** Application of freshwater drill cuttings shall only occur on sites having an:

(1) Electrical Conductivity (EC) no greater than 6,000 micromhos/cm; and

(2) Exchangeable Sodium Percentage (ESP) less than 15.0.

(d) **Sampling requirements.**

(1) The appropriate Field Inspector shall be contacted at least two business days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil and freshwater drill cuttings to be applied.

(2) The receiving soil shall be sampled using the following procedure:

(A) A minimum of five samples shall be taken for each one-half (1/2) mile section of road (or borrow ditch), well location, or production facility and composited into one sample for analysis.

(B) Sampling shall be to a minimum depth of six inches.

(3) The freshwater cuttings shall be sampled by taking a minimum of one representative sample for every five cubic yards of freshwater cuttings to be applied and composited into one quart sample for analysis.

(e) **Analysis requirements.**

(1) The composite samples of soil and drill cuttings shall be analyzed by a laboratory which tests soils.

(2) The parameters for the receiving soil shall include ESP and either EC or Total Dissolved Solids (TDS) or Total Soluble Salts (TSS).

(3) The parameters for the drill cuttings shall include TDS or Total Soluble Salts (TSS).

(f) **Maximum application rate.**

(1) The maximum application rate shall be calculated by the operator using the following formula:

PROCEDURE FOR CALCULATING APPLICATION RATE OF TOTAL DISSOLVED SOLIDS (TDS) OR TOTAL SOLUBLE SALTS (TSS)

_____ ppm TDS or TSS in receiving soil x 2 = _____ lbs/ac TDS or TSS in receiving soil.

10,000 lbs/ac TDS or TSS - _____ lbs/ac TDS or TSS in receiving soil = Maximum TDS or TSS (lbs/ac) to be applied _____.

Maximum TDS or TSS (lbs/ac) to be applied _____ ÷ (_____ ppm TDS or TSS in cuttings x .000001) = Maximum lbs/ac of cuttings to be applied _____.

Actual weight of drill cuttings _____ lbs/cu ft x 27 = _____ lbs/cu yd.

Maximum lbs/ac to be applied _____ ÷ _____ lbs/cu yd = _____ cu yds/ac to be applied.

Total volume _____ cu yds ÷ _____ cu yds/ac = Minimum acres required _____.

(2) Calculations shall be submitted with the application.

(g) **Permit requirements.**

(1) **Use of Form 1014X.** The application to apply freshwater drill cuttings shall be made on Form 1014X, which shall be submitted by electronic mail to the Manager of the appropriate Conservation Division District Office.

(2) **Landowner permission.** Attached to the application shall be written permission by the surface owner to allow the operator to apply freshwater drill cuttings as per this Section to a specific portion of real property as designated by legal description.

(3) **Telephone permits.** In case of an emergency, a District Manager may issue a permit by telephone. If an operator obtains a permit by telephone, the applicant shall file Form 1014X within five business days after receipt of the permit by telephone.

(4) **Conditions for permits.**

(A) The method to be used for application of freshwater drill cuttings shall not pollute surface or subsurface waters and shall protect public and private property adjoining the application area.

(B) During application, any necessary signs, lights, and other safety and warning devices shall be used as traffic requires to alert users to conditions. A sign shall be posted with the contractor's or operator's name to contact in case of an emergency.

(C) All free liquids shall be removed before cuttings are applied.

(D) Following completion of the project, there shall be a uniform soil/cuttings base.

(h) **Notice to Field Inspector.** The operator receiving the permit shall notify the appropriate Field Inspector at least two days prior to commencement of the application.

(i) **Site inspection.** At his discretion, a District Manager may request a Field Inspector of the Conservation Division or an Enforcement Officer of the Transportation Division to inspect the site at any time during the application operation to ensure compliance with this Section.

(j) **Duration of permit.** The permit shall state the duration of the permit, not to exceed 60 days. If a complaint is received or the operator fails to comply with either the terms of the permit or this Section, the District

Manager may direct the operator to cease application until the problem is resolved. If necessary, the District Manager may verbally revoke the permit and/or require the operator to perform remedial work. If a District Manager disapproves an application or cancels a permit, then the applicant may apply to the Commission for an order under 165:5-7-41.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-30. Enhanced recovery project surface facilities [REVOKED]

[**SOURCE:** Added at 9 Ok Reg 2337, eff 6-25-92; Revoked in Rule Making 980000034, eff 7-1-99]

165:10-7-31. Seismic and stratigraphic operations

(a) **Scope.** This Section shall cover the permitting, bonding, and plugging requirements for seismic exploration activities and stratigraphic test holes. Check-shots and vertical seismic profiles or other downhole wellbore seismic operations are excluded from this Section. Claims for damages sustained as a result of seismic operations, court proceeding costs and other matters concerning personal injury or property damage associated with seismic operations shall be brought in the district courts, pursuant to the Seismic Exploration Regulation Act (Okla. Stat. Tit. 52 §§ 318.21 through 318.23).

(b) **Definitions.** The following words and terms, when used in this Section, shall have the following meaning:

(1) **"Seismic exploration"** and **"seismic operation"** shall mean the drilling of seismic shot holes and use of surface energy sources such as weight drop equipment, thumpers, hydro pulses and vibrators and any of the activities associated therewith. This definition does not include surveying of the seismic area or the activity of conducting private negotiations between parties.

(2) **"Stratigraphic test holes"** shall mean holes drilled for the sole purpose of obtaining subsurface geological information through direct analysis of cores or cuttings or through the use of geophysical measurements that do not require the use of artificial sources of seismic energy.

(3) **"Operator"** or **"applicant"** shall mean the person or entity who is either the owner of the right to conduct seismic exploration or who acts on behalf of the owner.

(4) **"Surface estate"** shall mean the fee simple or absolute fee ownership of a tract of real property as defined by Okla. Stat. Tit. 60 §§5 and 23, less and excluding the mineral estate.

(5) **"Surface owner"** shall mean the owner or owners of record of the surface estate of the property upon which the seismic exploration is to occur, based upon the records of the county clerk of the county within which the surface estate is actually located.

(6) **"Technical information and data"** shall be defined as pre-plats as referenced in (c)(2)(B) and post-plats as referenced in subsection (c)(5).

(c) **Seismic permitting.**

(1) Before commencing any seismic operations in the State of Oklahoma, the applicant shall:

(A) Be duly registered with the Commission, including provision of a permanent address.

(B) Post a financial surety guarantee with the Commission.

(C) Provide to the Commission the name and business or field address of the contractor responsible for the operations being conducted.

(D) Obtain a permit from the Conservation Division for each seismic operation.

(E) Attempt to notify all owners of the surface estate where seismic operations will occur at least fifteen (15) days prior to commencement of operations on such surface estate. It shall be sufficient notice pursuant to this Section when notice is given to the current surface owner(s) at the last address shown of record for the surface owner in the records of the county clerk in the county where the surface estate is located, or an address that is known by applicant to be more accurate than the foregoing address of record. If the applicant has the right to conduct seismic operations and has attempted to give actual notice of intent to conduct seismic operations to the surface owner any time before fifteen (15) days prior to conducting seismic operations, such action shall be considered sufficient notification for the purposes of this Section. For the purposes of this Section, an attempt to notify shall be considered sufficient when the notification is sent by U.S. mail, the notice is postmarked at least fifteen (15) days prior to commencement of any seismic operations, and has been given at the last address shown of record for the surface owner in the records of the county clerk in the county where the surface estate is located, or an address which is known by applicant to be more accurate than the foregoing address of record.

(F) File an affidavit, within ninety (90) days of the last mailing of the notice, with the Commission and the county clerk in the county where the property is located, setting out that mailing of the notice has occurred in compliance with this Section and the Seismic Exploration Regulation Act (Okla. Stat. Tit. 52 §§ 318.21 through 318.23).

(G) The notice shall include a copy of the oil or gas lease or seismic permit or other legal instrument of similar nature authorizing the use of the surface for seismic operations and shall contain the information that is required for notices by Okla. Stat. Tit. 52 § 318.22.

(2) The applicant shall make application on the Commission's Form 1000S.

(A) The permit shall be valid for only one operation as approved on Form 1000S.

(B) A pre-plat of the operation area shall be attached to the application showing the location of the operation area delineated to the nearest section

(C) Post a performance bond in the amount of $50,000, or other form of surety in an amount as approved by the Conservation Division. The performance bond may be filed for each operation, or may be filed on an annual basis to cover all operations that may be undertaken during the year. If the performance bond is filed for a single operation, the amount may be approved by the Conservation Division for less than $50,000 or in another form of financial surety guarantee, depending on the nature of the seismic operation involved, the number of shot holes or surface energy source points, the cost of the operation and the size of the applicant's business. The form of surety shall not include letters of credit or financial statements. Such bond(s) or other surety may be released upon request made no sooner than thirty (30) days subsequent to the completion of the applicant's operation(s), which have been permitted under such bond(s) or other surety, upon satisfactory inspection or review by Conservation Division personnel.

(D) The permit shall expire twelve (12) months from the issue date, unless operations are commenced.

(E) The Conservation Division shall approve or deny the application within thirty (30) days of receipt of the application. The Conservation Division may act upon an application or amended application on an expedited basis.

(F) During any activity subject to this subsection, the applicant shall maintain at the site a copy of the approved permit, Form 1000S, for inspection.

(G) All technical information, excluding the Form 1000S, but including any plats, relative to the permitted operation shall remain confidential or the Conservation Division shall destroy the records. The plats and any other technical data submitted, shall be filed in the Technical Services Department of the Conservation Division. Upon request of the Manager of Field Operations, the technical data may be reviewed by Field Operations to ensure compliance with Commission rules.

(3) The operator shall file with the Conservation Division a written notice of commencement of seismic operations within 14 days after commencement of such operations.

(4) No seismic shot hole blasting shall be conducted within 200 feet of any habitable dwelling, building, or water well without written permission from the owner of the property or within 500 feet of any superfund site or hazardous waste facility.

(5) **Plugging and post-plat.** Within 30 days after completing a seismic operation, the applicant receiving the permit shall submit a copy of: the approved Form 1000S certifying the plugging of all seismic shot holes in compliance with this Section; and a post-plat or acceptable form of survey showing the actual location of all seismic shot holes.

Unless the applicant can demonstrate to the Conservation Division's District Office that another method will provide sufficient protection to groundwater supplies and long term land stability, the following guidelines shall be observed:

(A) Standard plugging method. All holes shall be filled to within four feet from the surface with bentonite, native cuttings, or an appropriate substitute. The remainder of the shot hole shall be filled and tamped with native cuttings or soil.

(B) Special methods. In areas where the standard plugging method has been shown to be inadequate for the prevention of groundwater contamination, the Conservation Division may designate the area as a special problem area. In such event, the Conservation Division will provide to the best of its ability, a clear geographical description of such area and the recommended, or required, hole plugging methods. Should the applicant encounter conditions such that the standard method appears inadequate for the prevention of groundwater contamination, the applicant shall inform the Conservation Division.

(i) Artesian flow. If the standard method is inadequate to stop artesian flow, alternate remedies must be employed to do so.

(ii) Water well conversion. Applicants are prohibited from allowing the conversion of seismic shot holes to water wells.

(iii) Groundwater protection. Alternative plugging procedures and materials may be utilized when the applicant has demonstrated to the Conservation Division's satisfaction that the alternatives will protect usable quality water.

(iv) Timeliness. All seismic shot holes shall be plugged as soon as possible and shall not remain unplugged for a period of more than 30 days after the drilling of the hole.

(d) **Stratigraphic test permitting.**

(1) Before commencing any stratigraphic test hole operations, those companies hereinafter referred to as the applicant shall:

(A) Be duly registered with the Commission, including provision of a permanent address.

(B) Post a financial surety guarantee with the Commission in compliance with 165:10-1-10.

(C) Obtain a permit from the Conservation Division for each stratigraphic test operation.

(2) The applicant shall make application on the Commission's Form 1000.

(A) The permit shall be valid for only one operation as approved on Form 1000.

(B) The permit shall expire twelve (12) months from the issue date, unless

operations are commenced.

(C) The Conservation Division shall approve or deny the application within 30 days of receipt of the application.

(D) Notice to surface owners shall be given according to OAC 165:10-3-1(g).

(E) During any activity subject to this subsection, the applicant shall maintain at the site a copy of the approved permit, Form 1000, for inspection.

(F) Any technical data submitted shall be filed in the Technical Services Department of the Conservation Division. Upon request of the Manager of Field Operations, the technical data may be reviewed by Field Operations to ensure compliance with Commission rules.

(G) The operator shall file with the Conservation Division a written notice of spudding of stratigraphic well within 14 days after spudding of the well.

(3) Unless the applicant can demonstrate to the Conservation Division's District Office that another method will provide sufficient protection to groundwater supplies and long term land stability, the following guidelines shall be observed:

(A) Surface casing requirements shall be met according to OAC 165:10-3-4.

(B) Storage and disposal of fluids associated with the drilling of stratigraphic test holes shall meet the requirements of OAC 165:10-7-16.

(C) Duty to plug and abandon shall be according to OAC 165:10-11-3.

(D) The Conservation Division shall be notified prior to commencement of plugging according to OAC 165:10-11-4.

(E) **Plugging.** Stratigraphic test holes shall be plugged according to OAC 165:10-11-6 and certification submitted on Form 1003 in compliance with OAC 165:10-11-7.

(e) Any person, firm, corporation or entity which conducts any seismic or stratigraphic test hole operations without a permit as provided in this Section, or in any other manner violates the rules of the Commission governing such operation shall be subject to a penalty up to One Thousand Dollars ($1,000.00) per violation per day after completion of the informal complaints procedure provided in OAC 165:10-7-7 and notice and hearing pursuant to the Commission's contempt proceedings.

(f) **Complaints.** A complaint alleging violations of this Section may be filed with the Commission against any person, firm or corporation conducting seismic and stratigraphic operation(s). The Commission may determine if and when a complaint has been adequately resolved, pursuant to the informal complaints process of OAC 165:10-7-7, and, if an environmental complaint, pursuant to the citizen complaint procedure of OAC 165:5-1-25.

[**SOURCE:** Added in Rule making 980000034, eff 7-1-99; Amended at 24 Ok Reg 1804 (RM 200700004), eff 7-1-2007; Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-32. Application to reclaim and/or recycle produced water for surface activities related to drilling, completion, workover, and production operations from oil and gas wells

(a) **Authority to reclaim and/or recycle produced water.** No person shall use produced water for any other purpose except as provided by this section. Any operator failing to obtain a permit may be fined up to $500.00.

(b) **Scope.** This Section shall cover the reclaiming and/or recycling of produced water from oil and gas wells for a single well location for the purpose of water supply for surface activities used for a specific permitted use. This does not include the use of produced water for down- hole operations referred to as weighted water under OAC 165:10-7-24(b)(2).

(c) **Quality of produced water.** For the purposes of this rule shall be limited to Total Dissolved Solids (TDS) or Total Soluble Salts (TSS) content not to exceed 5,000 mg/l and oil and grease content not to exceed 1,000 mg/l.

(d) **Storage of produced water.** If the produced water is stored in tanks, the tanks shall be legibly marked "recycle" water.
(e) **Log of load tickets.** The operator shall maintain copies of the load tickets from wells that the produced water was obtained. Such copies shall be made available to the OCC Inspector upon request.
(f) **Notification to OCC District Office.** The Operator shall orally notify the District Office when produced water is to be initially hauled to the permitted facility.
(g) **Application for permit.**
(1) The operator of the well must apply for the permit for the reclamation of produced water.
(2) Required Application. Each application for the reclaiming and/or recycling of produced water shall be submitted to the Field Operations District office on Form 1014D.
(3) A copy of written notice to the surface owner that the applicant intends to use produced water as per 165:10-7-32 to a specific portion of their real property as designated by legal description. For purposes of notice, a written waiver from the surface owner may also be submitted.

[**SOURCE:** Added in Rule making 200300001, eff 7-1-03; Amended in Rule Making 200600012, eff 7-1-2006]

165:10-7-33. Use of truck wash pits
(a) **Scope.** This Section shall apply to truck wash pits. A truck wash pit is a pit used for the temporary storage of fluids generated from the washing or cleaning of a motor vehicle, trailer or container used to transport or store deleterious substances. Truck wash pit operators shall comply with all applicable Commission rules in OAC 165:30 Motor Carriers.
(b) **Permit required.** Any truck wash pit sought to be approved after the effective date of this Section will require a permit issued by the Conservation Division. For use of a truck wash pit without a permit, the operator may be fined up to $2,000.00. The operator of the proposed pit shall submit Form 1014T to the Manager of Field Operations for the Conservation Division for review and approval. Documents required to be submitted with the Form 1014T include, but are not limited to, the following:
(1) A detailed drawing of the site, with complete construction plans drawn to scale for the proposed truck wash pit, any leachate collection system, and specific completion information for all monitor wells.
(2) A plat map with section, township, range and county showing the location of the proposed truck wash pit and the location of the monitor wells in relation to the pit they monitor.
(3) If the site on which the truck wash pit is to be located is not owned by the operator of the proposed pit, the operator must submit a copy of the written agreement between the operator and the surface owner authorizing use of the site for the pit. The agreement shall address the disposition of the pit (whether pit is to be buried on site, removed, etc.) at the termination or expiration of the agreement.
(c) **Surety requirements.**
(1) Any operator of a truck wash pit shall file with the Manager of Field Operations for the Conservation Division an agreement to properly close the pit upon termination of operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to comply with Commission rules or take remedial action as required by law and Commission rules, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.
(2) The Commission shall establish the amount of surety in the permit for the authority to operate a truck wash pit. The amount of surety shall be based on factors such as the dimensions of the pit, and costs of

reclamation, monitoring, plugging of monitor wells, pit closure, trucking of any deleterious substances, remediation and earth work. The amount may be subject to change for good cause. The surety shall be maintained for as long as monitoring is required. The type of surety shall be a corporate surety bond, certificate of deposit, irrevocable commercial letter of credit, or other type of surety approved by the permit. Any type of surety that expires shall be renewed prior to 30 days before the expiration date.

(d) **Site restriction.** No truck wash pit shall be constructed in any area that floods according to the Soil Conservation Service County Soil Survey (available for viewing at the Commission's Oklahoma City Office or appropriate Conservation Division District Offices).

(e) **Construction requirements.**

(1) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any truck wash pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit.

(2) **Pit specifications.** Any truck wash pit shall be constructed of concrete or steel or shall be lined with a geomembrane liner. The following specifications shall be met:

(A) Any concrete pit shall be steel-reinforced and have a minimum wall thickness of six inches.

(B) Any steel pit shall have a minimum wall thickness of three-sixteenths (3/16) inch. If a previously used steel pit is installed, it shall be free of corrosion or other damage.

(C) Any geomembrane liner shall meet these requirements:

(i) The geomembrane liner shall have a minimum thickness of 60-mils, shall be chemically compatible with the type of wastes to be contained, and shall have ultraviolet light protection.

(ii) The geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(iii) The geomembrane liner shall be continuous (may include welded or extruded seams) and shall cover the bottom and interior sides of the pit entirely. Sewing of seams is prohibited. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(3) **Certification of liner.** The operator of any truck wash pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(4) **Monitor wells or leachate collection system.**

(A) Any truck wash pit shall be required to have a leachate collection system or a minimum of three monitor wells, one upgradient and two downgradient from the pit.

(B) No monitor well shall be installed more than 100 feet from a truck wash pit, nor shall any existing water well be used as a monitor well, unless written approval is given by the District Manager or Manager of Field Operations.

(C) All new monitor wells shall be drilled to a depth of at least ten feet below the top of the first free water encountered and shall be drilled and completed by a licensed monitor well driller. If documentation is submitted prior to drilling the monitor well to show that no free water will be encountered within a depth of 50 feet from the surface, the District Manager may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the requirements as set out in rules established by the Oklahoma Water Resources Board, a removable and

lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when a well is being sampled. A key to each well shall be made available to the appropriate District Manager or Field Inspector upon request. Within 30 days of installation, specific completion information, a diagram of the locations and numerical labeling for all monitor wells shall be submitted to the appropriate District Manager.

(f) **Operation and maintenance requirements.**

(1) **Exclusion of runoff water.** No truck wash pit shall be allowed to receive runoff water.

(2) **Freeboard.** The fluid level in any concrete or steel truck wash pit shall be maintained at all times at least 6 inches below the top of the pit wall, unless otherwise specified on Form 1014T. Any geomembrane lined pit shall have a minimum of 24 inches freeboard at all times.

(3) **Sampling of monitor wells or leachate collection systems.**

(A) Sampling of monitor wells or leachate collection systems shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA-approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides, Total Dissolved Solids (TDS) and Total Petroleum Hydrocarbons (TPH) by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the District Manager or Manager of Field Operations.

(D) If requested by the District Manager, each sample shall be split and an adequate portion (approximately one pint) properly labeled and delivered upon request or otherwise provided to the appropriate Conservation Division District Office or Field Inspector. A copy of each analysis and a statement as to the depth to groundwater encountered in each well or leachate collection system, or a written statement that no water was encountered, shall be forwarded to the appropriate Conservation Division District Office within 30 days of sampling.

(4) **Prevention of pollution.** All truck wash pits shall be constructed, used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a truck wash pit, sufficient measures shall be taken to stop or control the loss of materials and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(5) **Oil film.** The operator of a truck wash pit shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all pits containing fluid be kept free of hydrocarbons, or be protected from access to birds. [See Advisory Notice in 165:10-7-3(c).]

(g) **Closure requirements.**

(1) **Time limit.** Within 90 days of the cessation of operation of any truck wash pit, such pit shall be emptied of all contents and filled with soil, except as otherwise provided in the written agreement between the operator and surface owner regarding the disposition of the pit at the termination or expiration of the agreement. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within 180 days.

(2) **Burial.** If any concrete, steel, geomembrane, or other materials associated with a truck wash pit are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(3) **Penalty for failure to meet closure requirements.** An operator who fails to meet the closure requirements set out in this subsection may be fined up to $2,000.00.

(h) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be imposed if the site has certain limitations or other conditions of risk exist.

(i) **Application to existing truck wash pits.** Operators of truck wash pits permitted prior to the effective date of this Section must either comply with subsections and paragraphs (c), (e)(1), (e)(4), (f), (g) and (h) of this Section or close such pits within one (1) year of the effective date of this Section. All truck wash pits permitted, but yet to be constructed as of the effective date of this Section, shall also be subject to the construction requirements in paragraphs (e)(2) and (e)(3) of this Section.

(j) **Variances.** A variance from the time requirements of paragraph (g)(1) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and supporting documentation is required.

[**SOURCE:** New at 31 Ok Reg 977, eff. 9-12-14 (RM 201400002); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-7-34. Use of reclaimed water in oil and gas operations

(a) **Scope.** This Section shall cover the permitting and use of reclaimed water from Department of Environmental Quality authorized facilities in oil and gas operations. Reclaimed water is wastewater from municipal wastewater treatment and/or public water supply treatment plants that has gone through various treatment processes to meet specific water quality criteria with the intent of being used in a beneficial manner.

(b) **Permit required.** No person shall use reclaimed water in oil and gas operations without applying for and obtaining a permit issued under this Section. An operator using reclaimed water without a permit may be fined up to $2,000.00.

(c) **Who may apply.** Only operators authorized to operate wells pursuant to OAC 165:10-1-10 may apply for this permit.

(d) **Required form and attachments.** Each application to use reclaimed water in oil and gas operations shall be submitted to the Manager of Field Operations on Form 1014RW. The form shall be properly completed and signed. Attached to the form shall be the following:

(1) Analysis of reclaimed water proposed to be used in oil and gas operations. Samples of reclaimed water shall be analyzed by a laboratory operated by the State of Oklahoma or accredited by the Department of Environmental Quality or in the North American Proficiency Testing System. Parameters for analysis of the reclaimed water shall include, but not be limited to, Total Dissolved Solids or Total Soluble Salts.

(2) Copies of all chain of custody forms related to sampling.

(3) A topographic map and the most recent aerial photograph (minimum scale 1:660) of the site where the reclaimed water is proposed to be used.

(4) Other information as required by this Section or requested by the Manager of Field Operations.

(e) **Review period.** The Manager of Field Operations shall review the application, either approve or disapprove it, and return a copy of Form 1014RW within five business days of submission of all required or requested information. If approved, a permit number shall be assigned to the Form 1014RW; if disapproved, the reason(s) shall be given. The applicant can apply for a hearing if the permit is not approved.

(f) **Violations.** If the operator violates the conditions of the permit or this Section, the use of reclaimed water in oil and gas operations shall be discontinued and the Field Operations Department shall be contacted

immediately. The Field Operations Department may revoke the permit and/or require the operator to do remedial work. If the permit is not revoked, use of reclaimed water in oil and gas operations may resume with the Field Operations Department's approval. If the permit is revoked, the operator may file an application for a hearing to reinstate the permit.

[**SOURCE:** Added at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

SUBCHAPTER 8. COMMERCIAL RECYCLING

PART 1. HYDROCARBON RECYCLING/RECLAIMING FACILITIES

PART 3. DRILLING WASTE RECYCLING/RECLAIMING FACILITIES [REVOKED]

[**Authority:** 52 O.S. Sections 139 and 141 (Supp. 1993)]

[**Source:** Codified 7-11-94]

PART 1. HYDROCARBON RECYCLING/RECLAIMING FACILITIES

165:10-8-1. Scope

This Part shall cover the permitting, construction, operation, and closure requirements for any recycling/reclaiming facility.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-2. Definitions

The following words and terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Tank bottom hydrocarbon recycling/reclaiming facility" means a recycling/reclaiming operation at a tank bottom reclaiming facility which is authorized by the Commission to recycle and/or reclaim marketable crude oil or condensate produced or used in the exploration or production of oil and gas. The facility shall comply with OAC 710:45-15-3.

"Hydrocarbon recycling/reclaiming facility at a saltwater disposal site" means a recycling/reclaiming operation at a Class II saltwater disposal site which is authorized by the commission to recycle and/or reclaim marketable crude oil or condensate produced or used in the exploration or production of oil and gas. The facility shall comply with OAC 710:45-15-3.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-3. Permit required

(a) **Who may apply.** The applicant for a recycling/reclaiming facility shall be the owner and/or lease holder of the site.

(b) **Compliance with Part.** Before issuance of a permit, the applicant shall comply with this Part and if pits are to be used for storage, the applicant shall comply with 165:10-9-1, except at Class II saltwater disposals.

(c) **OCC Form 1020A.** Application shall be filed on OCC Form 1020A.

(d) **An Oklahoma Tax Commission Reclaimer License.** The applicant shall have obtained a reclaimer license number under OAC 710:45-15-2. This number will be used by the Corporation Commission for its permit number.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-4. Application requirements

(a) **Permit required.** No recycling/reclaiming facility shall be constructed, enlarged, or used without approval on Form 1020A.

(b) **Site limitations.** Recycling/reclaiming facilities shall not be restricted by site limitations unless pits are to be used.

(1) Tank bottom hydrocarbon recycling/reclaiming facilities with pits that are to be used for storage in the operation shall comply with OAC 165:10-9-1.

(2) Hydrocarbon recycling/reclaiming facilities at a saltwater disposal site with pits that are used for unloading saltwater shall comply with OAC 165:10-9-3.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-5. Surety requirements for reclaimers

(a) **Agreement to close.** Any operator of a recycling/reclaiming facility shall file with the Manager of Document Handling an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of recycling/reclaiming operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the facility or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(b) **New facilities.** Category A (165:10-1-11) or Category B (165:10-1-13) surety shall be required for coverage of the closure costs, including well pluggings and general site restoration. These costs shall be calculated upon the projected costs of closure for the facility, based on estimated costs of earth work, remediation, revegetation, plugging, etc. Such information shall be provided by the applicant and reviewed, adjusted and ordered by the Commission.

(c) **Existing facilities.** For facilities in operation prior to the effective date of this Part, the Commission can require, by order, the establishment of an escrow account to cover the costs of closure, by using a per barrel fee to be deposited into the account. Any interest the account earns until the total amount is collected shall be reinvested in the account. Any interest accrued after the account balance is full shall be returned to the operator.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-6. Design and construction requirements

(a) **Spill prevention.** Each facility shall be designed and constructed utilizing good engineering practices. Design and construction standards shall be determined on a case-by-case basis by the Commission. Each such facility shall be designed and constructed to prevent escape of deleterious substances.

(b) **Unloading pits or sumps.** All unloading areas at tank bottom hydrocarbon recycling/reclaiming facilities that use a pit to receive fluids and skimming pits shall be approved on OCC Form 1014.

(c) **Required exhibits.** Complete construction plans, drawings, and written specifications for the proposed facility shall be submitted to the Manager of Pollution Abatement for review and approval. Design and construction standards shall be determined on a case-by-case basis by the Commission. Applicants shall consult with the Commission prior to the construction of the proposed facility. The Commission may apply existing technological standards and/or establish new standards, as it deems appropriate to the proposed site and activities. All plans, drawings, and specifications shall be prepared by or under the supervision of a qualified expert.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-7. Operation and maintenance requirements

(a) **Fencing.** All recycling/reclaiming facilities shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence. Final construction is subject to approval by the Manager of Pollution Abatement.

(b) **Sign.** A waterproof sign bearing the name of the operator, legal description, permit number, and emergency phone number shall be posted within 25 feet of the entrance gate to the facility and shall be readily visible.

(c) **Site security.** Receiving of any recycling/reclaiming material shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(d) **Acceptable materials.** Operators of a recycling/reclaiming facility shall only receive substances as defined in 165:10-1-2 "Deleterious substances."

(e) **Oil film.** OPERATORS TAKE NOTE: Federal statutes, such as the Bald Eagle Protection Act (16 U.S.C. Sections 668-668d), the Migratory Bird Treaty Act (16 U.S.C. Sections 703-711), the Endangered Species Act (16 U.S.C. Sections 1531-1542), and the Lacey Act Amendments of 1981 (16 U.S.C. Sections 3371-3378), dictate substantial fines and penalties for persons who allow birds of certain species to become fatally injured due to incidental contact with oil or oil by-products. These fines may be levied upon persons allowing such fatalities to occur, whether accidental or not. Misdemeanor and felony convictions may include imprisonment. Information on affected bird species, regulations under these Acts, and measures which can be taken to prevent such occurrences, such as the netting or covering of open-topped tanks and pits which contain oil or oil by-products, can be obtained from the U.S. Fish and Wildlife Service Office in Oklahoma City or the nearest Oklahoma Department of Wildlife Office.

(f) **Aesthetics.**

(1) All surface trash, debris, junk and scrap or discarded material connected with the operations of the facility shall be removed from the premises. With written permission from the surface owner, the operator may, without applying for an exception to 165:10-3-17(b), bury all nonhazardous material at a minimum depth of three feet; cement bases are included.

(2) The appropriate Conservation Division District Office or field inspector may issue a Form 1085 for any alleged violation of this subsection. If the operator fails to conduct cleanup as directed, the Commission may fine the operator $500.00 for a first offense. For a subsequent offense, the fine may

be up to $1,000.00, and the facility shall be shut down until completion for cleanup operations.

(g) **Structural integrity.** All recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent the escape of their contents. Any condition that threatens the structural stability of any diked portion or the storage facility shall be repaired in a timely manner.

(h) **Prevention of pollution.** All recycling/reclaiming facilities shall be used, operated, and maintained at all times so as to prevent pollution. In the event any non permitted discharge occurs, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in accordance with 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(i) **Fines.** For a willful non-permitted discharge from the facility, the operator may be fined up to $5,000.00.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00; Amended at 27 Ok Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 Ok Reg 1949, eff. 7-11-11 (RM 201000007)]

165:10-8-8. Reporting

(a) **Annual report on Form 1014A.** The operator of any recycling/reclaiming facility shall submit an annual report on Form 1014A to the Manager of Pollution Abatement, by February 1 of each year. In lieu of Commission Form 1014A, operators may submit Oklahoma Tax Commission Form 323A for the twelve calendar months of the previous year by February 1st.

(b) **Daily log for tank bottom at a hydrocarbon recycling/reclaiming facility.** The operator shall maintain a daily log and at a minimum shall include the date, volume, source (generator) and type of material. In addition, copies of any chemical analysis of materials or material safety data sheets shall be maintained.

(c) **Daily load tickets for hydrocarbon recycling/reclaiming facilities at salt water disposal facilities.** The operator shall keep the load tickets for saltwater and other deleterious substances received at the saltwater disposal facilities for a minimum of three years at the operator's office.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 200000002, eff 7-1-00]

165:10-8-9. Closure requirements

(a) **Notification.** The Manager of Pollution Abatement Department shall be notified in writing whenever a recycling/reclaiming facility shall be closed, or portions thereof, or becomes inactive unless it is shut down by the Commission.

(b) **Closed facility.** A recycling/reclaiming facility may be considered closed or inactive if the operator closes the facility, the operator is unable to furnish documentation to show that there has been receipt of deleterious substances during the last twelve months, the facility has been shut down by the Commission, or authority to operate has lapsed or is vacated by Commission order.

(c) **Closure plan.** An approved closure plan shall be submitted to the Pollution Abatement Department. Estimate of cost of closure shall be made part of the plan.

(d) **Monitor wells.** Monitor wells, if required, shall be plugged with bentonite or cement, upon approval in writing by the Manager of Pollution Abatement.

(e) **Pits.** When closing any pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids and sediments shall be removed.

(f) **Burial.** If any concrete, steel, geomembrane, or other materials associated with the site are to be left on-site, they shall be buried under a minimum soil cover of three (3) feet, pursuant to 165:10-3-7.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-10. Additional requirements

The requirements set forth in this Part are minimum requirements. Additional requirements may be made upon a showing of good cause.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

165:10-8-11. Variances

Except as otherwise provided in this Subchapter, variances from provisions of this Part may be granted by the Manager of Pollution Abatement or by order after application, notice, and hearing.

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94]

PART 3. DRILLING WASTE RECYCLING/RECLAIMING FACILITIES [REVOKED]

165:10-8-25. Scope [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-26. Definitions [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-27. Pit requirements [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-28. Application requirements [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-29. Surety requirements for reclaimers [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-30. Design and construction requirements [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-31. Operation and maintenance requirements [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-32. Reporting [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-33. Closure requirements [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-34. Additional requirements [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-8-35. Variances [REVOKED]

[**Source:** Added at 11 Ok Reg 3691, eff 7-11-94; Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

SUBCHAPTER 9. COMMERCIAL DISPOSAL FACILITIES

165:10-9-1. Use of commercial pits

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for any commercial pit. A commercial pit is a disposal facility which is authorized by Commission order and used for the disposal, storage, and handling of deleterious substances or soils contaminated by deleterious substances produced, obtained, or used in connection with drilling, production and/or pipeline construction operations. This does not cover disposal well pits. (See 165:10-9-3 and 165:10-7-20.)

(b) **Application requirements.**

(1) **Who may apply.** The applicant for a commercial pit shall be the owner of the land (or person having a written firm option to purchase the land at the time the application is filed) on which the proposed pit is to be located: if leased, both the owner and lessee shall be joint applicants.

(2) **Compliance with rules.** Before issuance of an order, the applicant shall comply with Commission Rules of Practice 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section. Subsequent to issuance of an order authorizing commercial pit(s) and prior to commencing construction of such pit(s), the applicant is required to submit a recorded copy of a deed to the Conservation Division reflecting that the applicant owns the land which is to be used for the commercial pit facility.

(3) **Exhibits.** Two complete sets of all exhibits which shall be relied upon by the applicant shall be submitted to the Pollution Abatement Department of the Commission, pursuant to 165:5-7-35. Those exhibits shall include, but are not limited, to the following:

(A) A lithologic log of test borings, identifying the subsurface materials encountered and the depth at which groundwater was encountered pursuant to (c)(2)(D) of this Section.

(B) Results of permeability tests of the proposed liner materials, pursuant to (e)(7) of this Section.

(C) A topographic map of the commercial pit site.

(D) The appropriate Soil Conservation Service (SCS) soil survey aerial photo and legend.

(E) A detailed drawing of the site, with complete construction plans drawn to scale by or under the supervision of a registered professional engineer.

(F) A plan for closure of the pit(s) which shall provide for a minimum three feet of soil cover and shall specifically state how all aspects of closure shall be accomplished, including volume and fate of liquids and solids, earthwork to close the pit(s) (including placement of stockpiled topsoil), and revegetation of the site.

(G) An itemization of projected hauling, closure, reclamation, maintenance, and monitoring costs.

(H) A plan for post-closure maintenance and monitoring which shall address maintenance of the site as well as monitoring and plugging of wells. Exemption from the plugging of monitor wells may be obtained upon written request and approval of the Manager of Pollution Abatement.

(I) A plan for operation which shall address the method(s) by which excess water will be disposed.

(c) **Restrictions.**

(1) **Order required.** No commercial earthen pit shall be constructed, enlarged, reconstructed, or used without a Commission order.

(2) **Site limitations.**

(A) No commercial earthen pit shall be constructed or used unless an investigation of the soils, topography, geology, and hydrology conclusively shows that storage of water-based drilling fluids and/or cuttings at the site will not be harmful to groundwater, surface water, soils, plants, or animals in the surrounding area. No abandoned mine, strip pit, quarry, canyon, or streambed shall be used for disposal of oilfield wastes, nor shall a pit be constructed or used in such a setting.

(B) No commercial pit shall be constructed or used on any site that is located within a 100-year flood plain.

(C) No commercial pit shall be constructed or used within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 USC Section 300h-7, Safe Drinking Water Act), or within one mile of a public water well for which the WPA has not been delineated.

(D) No commercial pit shall be constructed unless it can be shown that there will be a minimum of 25 feet between the bottom of the pit and the groundwater level. To ascertain this and to demonstrate the subsurface profile of the site, a minimum of three test borings (the exact number of locations to be determined by the Pollution Abatement Department) shall be drilled to a minimum depth of 25 feet below the proposed bottom of the pit and into the first free water encountered. Perched water tables are not considered for the purposes of this subparagraph. Test borings need not extend deeper than 50 feet below the bottom of the pit if free water has not been encountered before that depth. All boreholes converted to monitor wells shall conform to (e)(15) of this Section. All boreholes not converted to monitor wells shall be plugged from top to bottom with bentonite, cement, and/or other method approved by the Pollution Abatement Department within 30 days of drilling completion.

(E) No commercial pit shall be constructed or used within the following distances from the city limits of an incorporated municipality unless previously authorized by Commission order:

(i) Three miles if population is 20,000 or less.

(ii) Five miles if population is greater than 20,000.

(F) The construction, enlargement, reconstruction or operation of any commercial pit in any area listed in OAC 165:10-29-3 is prohibited.

(3) **Means of water disposal.** No commercial pit shall be constructed or used unless the operator can show that there will be an ongoing means of disposal of excess water pursuant to (b)(3)(I) of this Section.

(d) **Surety requirements.**

(1) **Agreement with Commission.** Any operator of a commercial pit shall file with the Manager of Document Handling for the Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of disposal operations due to abandonment, shutdown, full pits, or other reason. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the pits or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(2) **Surety amount and type.** The Commission shall establish the amount of surety in the order for the authority to construct, enlarge, or operate a commercial pit. The amount of surety shall be based on factors such as dimensions of the pit and costs of hauling, closure, reclamation, and monitoring. The amount may be subject to change for good cause. Upon approved closure of a pit, the Manager of Pollution Abatement may

administratively reduce the surety requirement to an amount which would cover the cost of monitoring the site and plugging the monitor wells. Surety shall be maintained for as long as monitoring is required. The type of surety shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of surety approved for the pit by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date.

(3) **Posting surety before permit is issued.** An operator shall post surety with the Commission before a construction permit is issued, pursuant to (e)(1) of this Section.

(e) **Construction requirements.**

(1) **Permit required.** Prior to constructing any pit, a commercial pit operator shall obtain a permit from the Manager of Pollution Abatement. Application shall be made on Form 1014N. For use of a commercial pit without a permit, the pit operator may be fined up to $5,000.00.

(2) **Runoff water prohibited.** No runoff water from surrounding land surfaces shall be allowed to enter a pit.

(3) **Stockpiling of topsoil.** Prior to constructing a pit, all topsoil within the top twelve inches of soil on the site shall be stockpiled for use as the final cover at the time of closure. The topsoil may be stockpiled in the outside slopes of the berms, provided it is not used for structural purposes and can be readily distinguishable from other soil materials at the time of closure. In cases where topsoil is stockpiled in the berms, it shall be shown in the as-built drawings pursuant to (e)(16) of this Section.

(4) **Monitoring by engineer.** A registered professional engineer or an engineer-in-training working under the supervision of a registered professional engineer (RPE) shall monitor the construction of any commercial pit to assure that approved design specifications and Commission rules are adhered to. A minimum of six on-site visits to the site shall be made; two pre-construction, two during construction, and two post-construction. At least the post-construction on-site visit shall be made by the RPE.

(5) **Maximum fluid depth.** Any pit shall be constructed to contain a maximum fluid or sediment depth of seven feet, with a minimum freeboard of three feet.

(6) **Maximum dimensions.** Any pit shall not be constructed to dimensions greater than that approved in the order. Furthermore, the maximum width of a pit or pit cell shall not exceed 175 feet if closure must be accomplished from one side or two adjacent sides; 350 feet if closure can be accomplished from at least two opposite sides or three adjacent sides. Pit dimensions shall be measured at the maximum allowable fluid level.

(7) **Soil liners.**

(A) Soil materials to be used in a soil liner shall undergo permeability testing before construction. Pre-construction permeability testing shall consist of laboratory permeability tests on at least two specimens of representative soil liner materials compacted in the laboratory to approximately 95 percent of the material's Standard Proctor Density (ASTM D-698).

(B) Laboratory permeability test procedures must conform to one of the methods described for fine-grained soils in the Corps of Engineers Manual EM-1110-2-1906 Appendix VII. In no case shall the pressure differential across the specimen exceed five feet of water per inch of specimen length.

(C) If permeability testing shows that addition of bentonite or other approved material is needed to assist the native soils in meeting the permeability standard, it shall be applied at a minimum rate specified by the testing or engineering firm. Any bentonite used for liner material shall not have been previously used in drilling muds.

(D) Any soil liner shall be constructed by disturbing the soil to the depth of the bottom of the liner, applying fresh water as necessary to the soil materials to achieve a moisture content wet of optimum, then recompacting it with heavy construction equipment, such as a footed roller, until the required density is achieved, pursuant to (H) of this paragraph. The liner shall be constructed in maximum six inch lifts (after compaction), with each lift being scarified before placement of the next lift.

(E) Any soil liner shall cover the bottom and interior sides of the pit entirely.

(F) Any soil liner shall be installed on a slope no steeper than 3:1 (horizontal to vertical).

(G) Any soil liner shall have a minimum thickness of 18 inches (after compaction) and shall have a maximum coefficient of permeability of 1.0 x 10^{-7} cm/sec.

(H) Any soil liner shall be field tested for compaction, unless a post-construction permeability test is performed pursuant to (I) of this paragraph.

(i) A minimum of six compaction tests shall be performed on any soil liner; a minimum of four widely spaced tests in the bottom of the pit and two tests on different slopes of the pit are required, unless otherwise directed by a Conservation Division representative. Particular emphasis shall be placed on selecting locations for compaction tests where nonuniformity in soil texture or color can be observed.

(ii) Compaction tests shall be conducted in accordance with ASTM methods D-2922 or D-1556.

(iii) The soil materials of any liner shall be compacted to at least 95 percent of the Standard Proctor Density.

(I) Post-construction permeability testing shall consist of at least two laboratory permeability tests on undisturbed samples of the completed soil liner.

(i) Particular emphasis shall be placed on selecting the location(s) for permeability tests or test samples where nonuniformity in soil texture or color can be observed.

(ii) Field permeability tests shall be conducted only by the double ring infiltrometer method as described in ASTM D-3385. Permeability tests may be discontinued prior to flow stabilization upon satisfactory evidence that the permeability rate is less than 1.0 x 10^{-7} cm/sec.

(8) **Geomembrane liners.**

(A) Any geomembrane liner that is installed in a commercial pit shall have a minimum thickness of 40 mil.

(B) Any geomembrane liner used in a commercial pit shall be chemically compatible with the type of substances to be contained and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include welded or extruded seams, and shall cover the bottom and interior sides of the pit entirely. Sewing of seams is prohibited. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(9) **Width of the crown.** The crown (top) of any berm shall be a minimum of eight feet in width.

(10) **Slopes.** The inside slope of any exterior berm (having fluid on one side) shall not be steeper than 3:1 (horizontal to vertical) and the

outside slope 2.5:1. The slopes of any interior berm (having fluid on both sides) shall not be steeper than 3:1.

(11) **Earthwork compaction.** All earthwork, except as noted in (7)(H)(iii) of this subsection, shall be compacted to achieve a minimum 90% Standard Proctor Density and shall be applied in lifts where some method of bonding is achieved between lifts, with each lift not to exceed eight inches prior to compaction.

(12) **Pipe installation.** Any pipe, tinhorn, culvert, or conduit in the berm between two adjoining pits shall be placed so that there is a minimum of 36 inches between the top of the pipe, tinhorn, culvert, or conduit and the lowest point in the top of the berm separating the pits.

(13) **Splash pad.** All pits which receive fluids directly from a vacuum truck shall have a splash pad at the point where fluids are received unless a waiver is obtained from the Manager of Pollution Abatement by showing that erosion of the liner will not occur. The pad must be constructed of materials and to the dimensions necessary to effectively prevent the liner from eroding.

(14) **Fluid level marker.** A minimum of one stationary fluid level marker shall be erected in each pit or cell. The marker shall be erected in a location within the pit or cell where it can be easily observed. The marker shall be of such design that the maximum fluid level at any time may be clearly identified. Details of the proposed marker installation shall be approved by the Manager of Pollution Abatement prior to installation. Markers shall be installed under the supervision of a registered professional engineer, licensed land surveyor, or other person approved by the Manager of Pollution Abatement prior to installation.

(15) **Monitor wells.** All commercial pits shall have a minimum of three monitor wells installed- one upgradient and two downgradient from the pit. The exact number and location of wells shall be approved by the Pollution Abatement Department prior to installation. No monitor well shall be installed more than 250 feet from the toe of the outside berm of a commercial pit, nor shall any existing water well be used as a monitor well unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site. All new monitor wells shall be drilled to a depth of at least ten feet below the top of the first free water encountered, and all monitor wells shall be drilled to a depth of at least ten feet below the base of the pit. All new monitor wells shall be drilled and completed by a licensed monitor well driller. If documentation is submitted to the Manager of Pollution Abatement prior to drilling the monitor wells to show that no free water will be encountered within 50 feet below the bottom of the pit, the Manager of Pollution Abatement may require that monitor wells be drilled to a lesser depth. All new monitor wells shall meet the requirements as set out in rules established by the Oklahoma Water Resources Board, in addition to the following requirements:

(A) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(B) Within 30 days of installation, specific completion information, a diagram of the locations and numerical labeling for all monitor wells shall be submitted to the Manager of Pollution Abatement.

(16) **As-built drawing.** A detailed, as-built drawing of the pit(s) and monitor wells by or under the supervision of a registered professional engineer shall be submitted to the Manager of Pollution Abatement before operation of the pit(s) commences.

(17) **Liner certification.** An affidavit signed by the person who was responsible for installing the pit liner, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules, shall be submitted to the Manager of Pollution Abatement before operation

of the pit commences. Supporting documentation shall also be submitted, such as post-construction permeability or compaction test results, bentonite receipts, and geomembrane liner specifications from the manufacturer.

(18) **Pit approval.** Acceptance of fluids into a pit shall not commence until a representative of the Conservation Division has inspected and approved the pit.

(19) **Hydrologically sensitive areas.** If the proposed site is known to be located over a hydrologically sensitive area, in addition to the foregoing construction requirements, the additional requirements shall apply:

(A) The total depth of a pit shall not exceed eight feet, and the total designed fluid or sediment depth shall not exceed five feet.

(B) A soil liner having a minimum thickness of three feet and a coefficient of permeability no greater than 1.0×10^{-8} cm/sec or a minimum 60-mil geomembrane liner shall be required.

(C) The Manager of Pollution Abatement shall determine the minimum depth of all monitor wells.

(f) **Operation and maintenance requirements.**

(1) **Vegetative cover.** Vegetative cover shall be established on all areas of earthfill immediately after pit construction or during the first planting season if pit construction is completed out of season. The cover shall be sufficient to protect those areas from soil erosion and shall be maintained.

(2) **Fencing.** All commercial facilities shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence.

(3) **Sign.** A waterproof sign bearing the name of the operator, legal description, most current order number, and emergency phone number shall be posted within 25 feet of the entrance gate to any commercial pit and shall be readily visible.

(4) **Site security.** Dumping into a commercial pit shall occur only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(5) **Fluid level.** Drilling fluids and/or cuttings shall not be accepted into a commercial pit unless the fluid level can be maintained at an elevation no higher than the maximum level of the fluid level marker.

(6) **Acceptable materials.**

(A) No operator of a commercial pit shall receive any substances other than water-based drilling fluids and/or cuttings or salt contaminated soils.

(B) No operator of a pit permitted prior to July 9, 1987, shall receive fluids and/or cuttings with a chloride content greater than 3500 mg/l. No operator of a pit permitted after July 9, 1987, shall receive fluids and/or cuttings with a chloride content greater than 5000 mg/l.

(C) A sample from each incoming load shall be collected, filtered using a standard API filter press, and tested for chlorides.

(D) The date, volume, source, and chloride level of each load received shall be entered into a log book. The log book shall be available for inspection by a representative of the Conservation Division of the Commission at all times. Log books shall be kept for a minimum of five years after closure is completed.

(7) **Pit contents.** No pit permitted prior to July 9, 1987, shall contain fluids and/or cuttings with a chloride content greater than 5,000 mg/l. No pit permitted after July 9, 1987, shall contain fluids and/or cuttings with a chloride content greater than 10,000 mg/l. The contents of each pit or pit cell shall be sampled and analyzed by the operator at least once every six months (during January and July) after operations commence. More

frequent sampling may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) A minimum of five samples per 50,000 bbls., or part thereof, is required for each pit or pit cell. Samples must be taken from different horizontally and vertically distributed locations in each pit or pit cell.

(D) The samples shall be combined and thoroughly mixed, then a minimum two pint composite sample taken for analysis.

(E) If requested by a representative of the Conservation Division, each composite sample shall be split and an adequate portion (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(F) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(G) All composite samples must be analyzed for chlorides by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(H) A copy of each analysis shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(8) **Oil film.**

(A) No commercial pit shall contain an oil film covering more than one percent of the surface area of the pit.

(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil films be removed, or the surface area covered by the film be protected from access to birds. (See Advisory Notice in 165:10-7-3(c).)

(9) **Aesthetics.** All commercial pit sites shall be maintained so that there is no junk iron or cable, oil or chemical drums, paint cans, domestic trash, or debris on the premises.

(10) **Structural integrity.** All commercial pits shall be used, operated, and maintained at all times so as to prevent the escape of their contents. All erosion, cracking, sloughing, settling, animal burrows, or other condition that threatens the structural stability of any earthfill shall be repaired immediately upon discovery.

(11) **Monitor wells.** Sampling of monitor wells shall begin prior to accepting any drilling fluids and/or cuttings into a new facility and within 30 days of drilling completion on existing facilities, and shall be done at least once every six months (during January and July) after operations commence until three years after closure is completed. Sampling of greater frequency of duration may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) If requested by a representative of the Conservation Division, an adequate portion of each sample (approximately one pint) shall be

properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(D) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(E) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required based on the operation of the facility as determined by the Manager of Pollution Abatement.

(F) A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or a written statement that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(12) **Prevention of pollution.** All commercial pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a commercial pit, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division. For a willful non-permitted discharge, the pit operator may be fined up to $5,000.00.

(g) **Semiannual report.** The operator of any commercial pit shall submit a semiannual report on Form 1014A to the Manager of Pollution Abatement by February 1 and August 1 of each year.

(h) **Closure requirements.**

(1) **Notification.** The Manager of Pollution Abatement shall be notified in writing whenever a commercial pit becomes inactive, is abandoned, full of sediment, or operation of the pit ceases for any reason. A commercial pit may be considered to be inactive by the Commission if:

(A) The pit has been shut down by the Commission because of a violation which results in the filing of an application for an order to vacate the operator's authority.

(B) The authority to operate has been terminated by failure to comply with (j) of this Section.

(C) The operator is unable to furnish documentation to show that there has been receipt of drilling fluids and/or cuttings into the pit during the previous twelve months.

(2) **Time limit.** Closure of all commercial pits shall be commenced within 60 days and completed within one year of cessation of pit operations, pursuant to (1) of this subsection. In cases where extenuating circumstances arise, one extension of six months may be administratively approved in writing by the Manager of Pollution Abatement. Closure shall be in accordance with an approved closure plan. A progress report shall be submitted to the Manager of Pollution Abatement, every three months (during January, April, July, and October) after cessation of pit operations until closure is completed.

(3) **Restrictive covenant.** A restrictive covenant shall be filed with the County Clerk of the county in which a commercial pit is located. The document shall accurately describe the pit location and shall specifically restrict the current or future landowners of the pit site from puncturing the final cover of the pit or otherwise disturbing the site to the extent that pollution could occur.

(4) **Penalty for failure to meet closure requirements.** An operator failing to meet the closure requirements set out in this subsection may be fined up to $1,000.00.

(i) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules and regulations, the site has certain limitations, or other conditions of risk exist.

(j) **Application to existing pits.** Subsections (a), (c)(1), (d), (e), (f), (g), (h), and (i) of this Section shall apply to all commercial pits permitted or ordered prior to the adoption of this Section. All pits permitted, but yet to be constructed as of the effective date of this Section, shall be subject to all of the construction requirements under (e) of this Section.
(k) **Variances.** Except as otherwise provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.
(l) **Compliance history.** In the event the Commission has evidence that an applicant for a commercial disposal pit may not possess a satisfactory compliance history with Commission rules, the Director of the Conservation Division may seek an order of the Commission, issued after application, notice, and hearing, determining whether the applicant should be authorized to operate such a facility.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-9-2. Commercial soil farming
(a) **Order required.** No person shall conduct commercial soil farming without an order of the Commission.
(b) **Site suitability restrictions.** Commercial soil farming shall only occur on a tract of land having all of the following characteristics [paragraphs (1) through (5) shall be determined by the appropriate Soil Conservation District or a qualified soils expert]:
(1) A maximum slope of five percent.
(2) Depth to bedrock no less than 20 inches.
(3) A soil profile containing at least twelve inches of one of the following U.S.D.A. soil textures:
(A) loam
(B) silt loam
(C) silt
(D) sandy clay loam
(E) clay loam
(F) silty clay loam
(G) sandy clay
(H) silty clay or clay
(4) No commercial soil farming operations shall be conducted on any site that is located within a 100-year flood plain.
(5) Slight salinity (defined as electrical conductivity less than 4,000 micromhos/cm) in the topsoil or upper six inches of the soil.
(6) An Exchangeable Sodium Percentage (ESP) less than 15.
(7) A water table deeper than 25 feet from the soil surface, excluding perched water tables (submit basis for this determination).
(8) A minimum distance of 100 feet from any stream designated by Oklahoma Water Quality Standards or any fresh water pond, lake, or wetland (available for viewing at the Commission's Oklahoma City or appropriate Conservation Division District Offices).
(9) The site shall not be located within three (3) miles upstream within the watershed for any lake used for public water supply.
(10) No commercial soil farming operations shall be conducted within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 USC Section 300h-7, Safe Drinking Water Act), or within one mile of a pubic water well for which the WPA has not been delineated.

(11) No commercial soil farming operations shall be conducted within the following distances from the city limits of an incorporated municipality unless previously authorized by Commission order:

(A) Three miles if population is 20,000 or less.

(B) Five miles if population is greater than 20,000.

(c) **Application requirements.**

(1) **Who may apply.** The applicant or joint applicant for commercial soil farming shall be the owner of the land (or person having a firm option, in writing, to purchase the land) which is to be used for soil farming.

(2) **Order required.** The Commission may issue an order upon compliance with Commission Rules of Practice 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section. Subsequent to issuance of an order authorizing commercial soil farming and prior to commencing soil farming operations, the applicant is required to submit to the Conservation Division a recorded copy of a deed reflecting that the applicant owns the land which is to be used for commercial soil farming.

(3) **Required exhibits.** All exhibits intended to support an application shall be filed pursuant to 165:5-7-35. The exhibits shall include the following:

(A) A site suitability report, pursuant to (b) of this Section, provided by the appropriate Soil Conservation District or a qualified soils expert (include qualifications). The report must contain a U.S.D.A. Soil Survey map, or when Soil Survey map does not have adequate detail, a map prepared by a qualified soils expert. A legend and soil type description shall be attached.

(B) Plan of conservation management practices covering needs of storm water disposal and erosion control.

(C) A well-prepared map or diagram, drawn to scale, showing the size and configuration of the individual soil farming plots. Latitude and longitude coordinates designating the corners of the individual soil farming plots must be supplied. The map or diagram must also include filter strips, receiving pit(s), and staging area(s).

(D) A topographic map of the subject area.

(E) Initial soil analysis with a map indicating the location of soil samples.

(F) A detailed discussion of the method of application and use of filter strips and provisions for preventing runoff from the application area.

(G) A detailed description of how the receiving pit(s) and staging area(s) are to be constructed, including, but not limited to, designation of the materials to be used for construction of the receiving pit(s) and staging area(s).

(d) **Sampling requirements.**

(1) **Contact with appropriate Conservation Division District Office.** The appropriate Conservation Division District Office shall be contacted at least two business days prior to sampling to allow a Commission representative an opportunity to witness the sampling of the receiving soil.

(2) **Receiving soil.** Subsequent to the preparation of a conservation plan or site suitability report, soil samples shall be taken from the proposed soil farming plot and analyzed. Analysis shall be submitted pursuant to (c)(3)(E) of this Section. Soil sampling shall follow this procedure:

(A) If the site contains soil types from different parent material, separate areas shall be established for soil sampling and loading calculations.

(B) A sample area shall not exceed 40 acres.

(C) A minimum of 20 representative surface core samples (0-6 inches) and 20 representative subsurface core samples (18-30 inches) must be taken from each sample area. The samples shall be composited for

analysis of a single surface core sample and a single subsurface core sample.

(3) **Sampling incoming loads of mud and/or cuttings.** A sample from each incoming load of mud and/or cuttings shall be collected, filtered using a standard API filter press, and tested for Total Dissolved Solids (TDS). The date, volume, source, and TDS level of each incoming load of mud and/or cuttings received shall be entered into a log book. The log book shall be available for inspection by a representative of the Conservation Division. Log books shall be kept for a minimum of five years.

(4) **Sampling of mud and/or cuttings to be soil farmed.** The mud and/or cuttings to be soil farmed shall be sampled using the following procedures:

(A) A minimum of five samples per 50,000 bbls., or part thereof, each representative of the materials to be soil farmed, is required for each pit or pit cell. Samples must be taken from different horizontally and vertically distributed locations in each pit or pit cell.

(B) The samples shall be combined and thoroughly mixed, then a minimum two pint composite sample shall be taken for TDS and percent of solids analysis, a minimum three pint composite sample taken for oil and grease analysis, and a minimum two pint composite sample taken for arsenic and chrome analysis.

(C) If requested by a representative of the Conservation Division, each composite sample for TDS and percent of solids analysis shall be split and an adequate portion (approximately one pint) properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(D) After samples have been taken for analysis from a pit or pit cell, the operator shall not allow the addition of fluids or other materials, except natural precipitation or fresh water, to decrease the viscosity of the fluid.

(e) **Analysis requirements.**

(1) **Approved laboratory.** Soil and mud and/or cuttings samples shall be analyzed by a laboratory operated by the State of Oklahoma or certified by the Oklahoma Department of Environmental Quality.

(2) **Soil.** Parameters for analysis of soil shall include, but are not limited to pH, Total Soluble Salts (TSS) or Electrical Conductivity, and Exchangeable Sodium Percentage (ESP).

(3) **Mud and/or cuttings contents.** Parameters for analysis of mud and/or cuttings contents shall include, but are not limited to, the following: pH, TDS, Electrical Conductivity, Arsenic, Chromium and Oil and Grease. Arsenic and Chromium may be analyzed by either Nitric Acid Extraction or Acetic Acid Extraction ("Test Methods for Evaluating Solid Waste," SW846, second edition, U.S. EPA). The analysis shall specify which method of extraction was used.

(f) **Maximum application rate.**

(1) **Loading limits.**

(A) The maximum application rate (loading limit) shall be calculated by the operator using the calculations in (g) of this Section and the following soil loading standards:

(i) Total Soluble Salts: 6,000 lbs/acre (less TSS in soil).

(ii) Arsenic: 80 lbs/acre.

(iii) Chromium: 80 lbs/acre.

(iv) Oil and Grease: 40,000 lbs/acre.

(v) Total Dry Weight: 200,000 lbs/acre.

(B) Limitations in (A) of this paragraph are based upon standards set forth in the following publications:

(i) "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook, No. 60, U.S. Salinity Laboratory, Riverdale, California, 1954

(ii) "Critical Concentrations for Irrigation Water Supplies," Water Quality Criteria, 1972 Ecological Research Series, EPA-R2-73-033, March, 1973

(iii) H.R. Moseley, "Summary and Analysis of API Onshore Drilling Mud and Produced Water Environmental Studies," American Petroleum Institute Bulletin, No. D-19, 1983

(2) **Determination of most limiting parameter.** The maximum application rate shall be restricted by the most limiting parameter. It may require more than one application to achieve the maximum application rate while avoiding runoff. Determination of the most limiting parameter is based upon concentrations found in the 0"-6" soil profile at the soil farming site.

(3) **Records required.** Accurate records shall be kept as to when, where (which application area), and how much is applied. The operator shall make such records available at all times for inspection by a representative of the Conservation Division. Additionally, a semiannual report shall be submitted to the Manager of Pollution Abatement, pursuant to (k) of this Section.

(4) **Additional soil sampling required when sixty percent of the maximum application rate is obtained.** Additional soil sampling and analysis of a plot shall be done prior to each soil farming application when records show that 60 percent of the maximum application rate in (1) of this subsection of any parameter except total weight is reached. Requirements of (d) and (e) of this Section shall be met. Soil farming shall not be permitted on a plot if the analysis indicates that more than 95 percent of the maximum application rate of any parameter has been reached or if the ESP is greater than 15.

(g) **Calculations.** The procedures described in Appendix H of this Chapter shall be used in calculating the maximum application rate.

(h) **Operation requirements.**

(1) **Surety required.**

(A) Any operator of a commercial soil farming site shall file with the Manager of Document Handling for the Conservation Division an agreement to clean up pollution, restore the site, and/or plug monitor wells upon termination of operations. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to comply with the rules or take remedial action as required by law and this Section, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(B) The Commission shall establish the amount of surety in the order for the authority to operate a commercial soil farming site. The amount may be subject to change for good cause. The surety shall be maintained for as long as monitoring is required. The type of surety shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of surety approved by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date.

(2) **Sign required.** A waterproof sign bearing the name of the operator, legal description, order number, and emergency phone number shall be posted within 25 feet of the entrance to any commercial soil farming site and shall be readily visible.

(3) **Monitor wells.**

(A) Any commercial soil farming operation shall be required to have a minimum of three (3) monitor wells installed- one upgradient and two (2) downgradient. The exact number and location of wells shall be established by the Pollution Abatement Department.

(B) No monitor well shall be installed more than 250 feet from a commercial soil farming operation, nor shall any existing water well be

used as a monitor well, unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site.

(C) All new monitor wells shall be drilled to a depth of at least ten feet below the top of the first free water encountered, and shall be drilled and completed by a licensed monitor well driller. If documentation is submitted to the Manager of Pollution Abatement prior to drilling the monitor wells to show that no free water will be encountered within a depth of 50 feet from the surface, then the Manager of Pollution Abatement may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the requirements as set out in rules established by the Oklahoma Water Resources Board, in addition to the following requirements:

(i) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(ii) Within 30 days after installation, specific completion information, a diagram of the locations of all monitor wells in relation to the soil farming site, and numerical labeling of such monitor wells shall be submitted to the Manager of Pollution Abatement.

(4) **Sampling of monitor wells.** Sampling of monitor wells shall begin prior to the first soil farming application and shall be done once every six months (during January and July) after operations commence until one year after the last application is made, then once every year for three years according to the following:

(A) The appropriate District Manager shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards ("RCRA Groundwater Monitoring Technical Enforcement Guidance Document," EPA, OSWER-9950.1, September, 1986, pp.99-107.)

(C) If requested by a representative of the Conservation Division, an adequate portion of each sample (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(D) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required based on the operations as determined by the Manager of Pollution Abatement.

(E) A copy of each analysis and a statement as to the depth to groundwater encountered in each well, or a written statement that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(5) **Representative soil analysis.** A representative soil analysis of the active soil farming plot (or plots) shall be submitted to the Manager of Pollution Abatement with the semiannual report on Form 1014A. The analysis shall include TSS, oil and grease, ESP, arsenic and chrome.

(6) **Site Security.** Soil farming shall only occur when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(i) **Conditions of operation.**

(1) **Required form.** A completed Form 1014CS shall be submitted to the Manager of Pollution Abatement for approval prior to commencement of soil farming.

(2) **Notice to Commission.** The applicant, by agreement with the Conservation Division, shall schedule the commencement of soil farming no less than 24 hours prior thereto, to allow a Commission representative to be present to witness the work.

(3) **Presence of representative.** A representative of the applicant shall be on the soil farming site at all times during application of the pit materials to the land.

(4) **Type muds to be soil farmed.** Commercial soil farming is limited to water-based type muds and/or cuttings. At the time of land application, soil farming of water-based type muds and/or cuttings with a chloride content greater than 5,000 mg/l shall be prohibited. Soil farming of mud containing asphalt based oil, or oil-based muds and/or cuttings shall be prohibited.

(5) **Weather restrictions.** Commercial soil farming shall not be done:

(A) During precipitation events.

(B) When the soil moisture content is at a level such that the soil would not readily take the addition of drilling fluids.

(C) When the ground is frozen.

(D) By spray irrigation when the wind velocity is such that even distribution of materials cannot be accomplished or the buffer zones, pursuant to (6) of this subsection, or filter strips, pursuant to (7) of this subsection, cannot be maintained.

(6) **Buffer zones:** No commercial soil farming shall be done within the following buffer zones:

(A) One hundred feet of a property line boundary.

(B) Fifty feet of any stream not designated by Oklahoma Water Quality Standards.

(C) Three hundred feet of any actively-producing water well used for domestic, irrigation or industrial purposes.

(D) One thousand three hundred feet of any public water well.

(7) **Filter strips.** No commercial soil farming shall be done on filter strips. Filter strips must have a minimum width of 100 feet, and vegetation must be maintained on filter strips.

(8) **Application rate.** The maximum application rate of drilling fluids and/or cuttings stipulated by the permit shall not be exceeded. Furthermore, the minimum required acreage within the approved soil farming plot, as designated by the permit, shall be fully utilized. Application of drilling fluids and/or cuttings outside the approved plot shall be prohibited.

(9) **Soil farming method.**

(A) Application of mud and/or cuttings shall be uniform over the soil farming plot and shall be made by injection, spray irrigation, or other method approved by the Commission prior to use. The flood irrigation method shall be limited to those fields that normally are irrigated in that manner.

(B) An application of more than 50,000 lbs/acre of dry weight materials or more than 500 lbs/acre of oil and grease shall be incorporated into the soil by injection, disking, or other method approved by the Commission. If the injection method is not used, incorporation must be made within a reasonable time period after completion of application, not to exceed 14 days unless extended by the Pollution Abatement Department pursuant to a written request.

(C) When the spray irrigation method is used and solids eventually accumulate on the soil surface to a one-eighth (1/8) inch depth, then the materials shall be incorporated prior to subsequent soil farming.

(D) All soil farming vehicles shall be either a single or double axle vehicle with a permanently attached tank that shall not exceed 100

barrels, and the vehicle shall be equipped so as to minimize pooling and ruts caused by tire tracks. It shall have a diffuser mechanism to spread the mud/fluids in a fan pattern. Spreader bars shall not be used. The mud/fluids shall be forced from the tank with air pressure or a mechanical pump. Gravity application is prohibited. Transport/tanker trucks (18 wheel vehicles) shall not be used for soil farming at any time. Use of an unauthorized vehicle or equipment may result in the revocation of authority to soil farm. A fine of up to $2,000.00 may be assessed for each violation of this paragraph.

(E) Drill cuttings shall be spread with an industrial mechanical spreader capable of broadcasting and/or fanning out the cuttings. Dozers, backhoes, motor blades or scrapers shall not be used to spread drill cuttings or drill solids during soil farming at any time. Any other equipment must be approved by the Manager of Pollution Abatement prior to commencement of operations.

(10) **Runoff or ponding prohibited.** No runoff or ponding of soil farmed materials shall be allowed during application.

(11) **Suspension of soil farming authority.** If the applicant violates the order authorizing soil farming, or this Section, soil farming shall be discontinued and the Pollution Abatement Department shall be contacted immediately. The Pollution Abatement Department may shut down the facility until the operator completes any remedial work. Soil farming may resume with the approval of the Pollution Abatement Department.

(12) **Prevention of pollution.** All commercial soil farming facilities shall be operated and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from a commercial soil farming facility, sufficient measures shall be taken to stop or control the loss of materials and reporting procedures in 165:10-7-5 (c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(13) **Vegetative cover.** If the vegetative cover of the area which has been soil farmed is destroyed or significantly damaged by disking, injection, or other practice associated with soil farming, the vegetative cover shall be reestablished within one year after the last soil farming application.

(14) **Fencing.** All commercial soil farming sites shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence.

(j) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules, or the site has certain limitations, or other conditions of risk exist.

(k) **Semiannual report.** The operator of any commercial soil farming facility shall submit a semiannual report on Form 1014A to the Manager of Pollution Abatement by February 1 and August 1 of each year.

(l) **Prospective application to existing operations.** Subsections (d), (e), (f), (g), (h), (i), (j), (k) and (m) of this Section shall apply to all commercial soil farming operations for which an order or permit was obtained prior to the adoption of this Section. All affected operators shall have their facility in compliance with all of the noted subsections by December 31, 1988. Failure to be in compliance by that date shall result in termination of the authority to operate.

(m) **Variances.** Except as provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.

(n) **Compliance history.** In the event the Commission has evidence that an applicant for a commercial soil farming operation may not possess a satisfactory compliance history with Commission rules, the Director of the Conservation Division may seek an order of the Commission, issued after application, notice,

and hearing, determining whether the applicant should be authorized to conduct such commercial soil farming operation.

[**Source:** Amended at 12 Ok Reg 2017, eff 7-1-95; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-9-3. Commercial disposal well surface facilities

(a) **Scope.** This Section shall apply to the surface facilities of any commercial disposal well. Any pit sought to be approved pursuant to this Section will require a permit. The operator of the proposed pit shall submit Form 1014 to the appropriate Conservation Division District Office for review and approval.

(b) **Notice.**

(1) **Notice of application.** Notice of the application for a permit for a pit with a capacity in excess of 50,000 barrels shall be published one time in a newspaper of general circulation in Oklahoma County, Oklahoma, and in a newspaper of general circulation published in each county in which the subject lands are located. The notice shall include the following information:

(A) The name, physical mailing address, telephone number, electronic mail address and facsimile number of the applicant or its representative, whom anyone may contact for additional information concerning the application.

(B) The location of the proposed pit to the nearest 40 acre tract.

(C) The capacity of the proposed pit.

(D) The type of fluids to be stored in the proposed pit.

(E) The notice must also include the following language:

(i) Written protests to the relief sought must be submitted to the applicant or its representative and to the Manager of the Field Operations Department, Oklahoma Corporation Commission, P.O. Box 52000, Oklahoma City, OK, 73152-2000, within fifteen (15) days after publication of the notice. Written protests must specify the name of the applicant, location of the proposed pit, reasons for protest, and the name(s), physical mailing address(es), telephone number(s), electronic mail address(es) and facsimile number(s) of the protestant(s).

(ii) If there are no written protests to the application and the Commission does not require a hearing, the application shall be presented to the Manager of the Field Operations Department for administrative review without a hearing, and if the application is protested, then any protestants shall receive notice of hearing.

(2) **Proof of notice.** The applicant shall submit affidavit(s) of publication to the Field Operations Department to show compliance with the requirements of paragraph (b)(1) above.

(3) **Procedure.**

(A) If a written protest to the application is submitted to the Field Operations Department within fifteen (15) days after the date the notice of application is published, or if hearing is required by the Commission, the application shall be set for hearing and notice thereof given in the same manner required in the filing of an application on the Pollution Docket.

(B) If no written protest is submitted to the Field Operations Department and the Commission does not require a hearing, the application shall be presented to the Manager of the Field Operations Department for administrative review.

(c) **Site restriction.** No commercial disposal well pit shall be constructed in any area that floods according to the Soil Conservation Service County Soil Survey (available for viewing at the Commission's Oklahoma City Office or appropriate Conservation Division District Offices).

(d) **Construction requirements.**

(1) **Dikes.** A dike shall be constructed and maintained around any storage tank or group of tanks. The diked area shall be capable of totally containing at least one and one-half (1 1/2) times the volume held by the largest storage tank.

(2) **Leak containment.** A means for containing leaks shall be provided at all pumps and connections.

(3) **Splash pad/apron.** A splash pad/apron shall be constructed at the unloading area of any pit to the design and dimensions necessary to contain and direct all materials unloaded into the pit. If a pit is not used, an apron shall be constructed at the unloading area to the design and dimensions necessary to direct any spills into containment.

(4) **Pit specifications.** Any commercial disposal well pit shall be constructed of concrete or steel or shall be lined with a geomembrane liner. The following specifications shall be met:

(A) Any concrete pit shall be steel-reinforced and have a minimum wall thickness of six inches.

(B) Any steel pit shall have a minimum wall thickness of three-sixteenths (3/16) inch. If a previously used steel pit is installed, it shall be free of corrosion or other damage.

(C) Any geomembrane liner shall meet these requirements:

(i) The geomembrane liner shall have a minimum thickness of 40 mils, shall be chemically compatible with the type of wastes to be contained, and shall have ultraviolet light protection.

(ii) The geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(iii) The geomembrane liner shall be continuous (may include seams) and shall cover the bottom and interior sides of the pit entirely. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(5) **Certification of liner.** The operator of any commercial disposal well pit that is constructed with a geomembrane liner shall secure an affidavit signed by the installer, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules. It shall be the operator's responsibility to maintain the affidavit and all supporting documentation pertaining to the liner, such as geomembrane liner specifications from the manufacturer, etc., and shall make them available to a representative of the Conservation Division upon request.

(6) **Monitor wells or leachate collection system.**

(A) Any commercial disposal well pit permitted, but yet to be constructed after the effective date of this Section, shall be required to have a leachate collection system and a minimum of three monitor wells, one upgradient and two downgradient from the pit.

(B) No monitor well shall be installed more than 100 feet from a commercial disposal well pit, nor shall any existing water well be used as a monitor well, unless written approval is given by the Manager of Pollution Abatement.

(C) All new monitor wells shall be drilled to a depth of at least ten feet below the top of the first free water encountered and shall be drilled and completed by a licensed monitor well driller. If documentation is submitted prior to drilling the monitor well to show that no free water will be encountered within a depth of 50 feet from the surface, the Manager of Pollution Abatement may require that monitor wells be drilled to a lesser depth.

(D) All new monitor wells shall meet the requirements as set out in rules established by the Oklahoma Water Resources Board, in addition to the following requirements:

(i) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when a well is being sampled. A key to each well shall be made available to the appropriate District Manager or Field Inspector upon request.

(ii) Within 30 days of installation, construction details for any leachate collection system or specific completion information for all monitor wells, a diagram of their locations in relation to the pit they monitor, and the numerical labeling of such monitor wells shall be submitted to the Manager of the Underground Injection Control Department.

(e) **Operation and maintenance requirements.**

(1) **Sign.** A waterproof sign shall be erected and maintained within 25 feet of the entrance road to any commercial disposal well, shall be readily visible, and shall contain the name of the operator, order or permit number, legal description, and emergency phone number.

(2) **Fencing.** All commercial disposal well surface facilities that have a pit shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence.

(3) **Site maintenance.** The normal access surface of any commercial disposal well site, including the access road(s), shall be maintained in a condition that will safely and easily accommodate a passenger car during all weather conditions.

(4) **Exclusion of runoff water.** No commercial disposal well pit shall be allowed to receive runoff water.

(5) **Freeboard.** The fluid level in any concrete or steel commercial disposal well pit shall be maintained at all times at least 6 inches below the top of the pit wall, unless otherwise specified on Form 1014. Any geomembrane lined pit shall have a minimum of 24 inches freeboard at all times.

(6) **Temporary storage only.** No pit shall be used as permanent storage for salt water.

(7) **Sampling of monitor wells and leachate collection systems.**

(A) Sampling of monitor wells and leachate collection systems shall occur once every six months, during the months of January and July.

(B) The appropriate District Manager or field inspector for the area shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(C) Samples shall be collected, preserved, and handled by the operator according to EPA-approved standards (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September, 1986, pp. 99-107) and analyzed for pH, chlorides and Total Dissolved Solids (TDS) by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the District Manager or Manager of Field Operations.

(D) If requested by the District Manager, each sample shall be split and an adequate portion (approximately one pint) properly labeled and delivered upon request or otherwise provided to the appropriate Conservation Division District Office or Field Inspector. A copy of each analysis and a statement as to the depth to groundwater encountered in each well or leachate collection system, or a written statement that no water was encountered, shall be forwarded to the Manager of the Underground Injection Control Department, within 30 days of sampling.

(8) **Prevention of pollution.** All commercial disposal well pits shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge from surface facilities of a commercial disposal well, sufficient measures shall be taken to stop or

control the loss of materials and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division.

(9) **Oil film.** The operator of a saltwater disposal system shall be responsible for the protection of migratory birds. Therefore, the Conservation Division recommends that to prevent the loss of birds due to oil films, all open top tanks and pits containing fluid be kept free of hydrocarbons, or be protected from access to birds. [See Advisory Notice 165:10-7-3(c).]

(10) **Site security.** Commercial disposal well facilities must be secured at all times so as to prevent unauthorized access. If an electronic system is used to secure the facility or if fluids to be disposed in the well are transported to the facility by pipe, an automatic shut-off or alarm system must be installed to ensure that disposal operations cease if a well mechanical failure or downhole problem occurs. If an electronic system is not used to secure the facility, fluids shall be received for placement in a commercial disposal well only when there is an attendant on duty if fluids are hauled in by truck. All sites not protected by an electronic system shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock or electronic security system access code shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(f) **Closure requirements.**

(1) **Time limit.** Within 90 days of the cessation of operation of any commercial disposal well, all associated pits shall be emptied of all contents and filled with soil. All monitor wells shall be plugged with bentonite or cement, unless exempt in writing by the District Manager or Manager of Field Operations. The site shall be revegetated within 180 days.

(2) **Geomembrane-lined pits.** When closing any commercial disposal well pit with a geomembrane liner, extreme care shall be taken to preserve the integrity of the liner. All free liquids shall be removed or chemically solidified. A geomembrane cap shall be placed over the top of any remaining contents to completely encapsulate them. Any geomembrane cap shall have a minimum thickness of twelve mils and shall be chemically compatible with the type of substances to be encapsulated. Burial, pursuant to (3) of this subsection, shall follow.

(3) **Burial.** If any concrete, steel, geomembrane, or other materials associated with a commercial disposal well site are to be left on-site, they shall be buried under a minimum soil cover of three feet, pursuant to 165:10-3-17.

(g) **Prospective application to existing facilities.** All provisions of this Section except (4) and (5) of subsection (d) shall apply to all existing commercial disposal well pits which are, or have been, in operation prior to the effective date of this Section. Operators shall have 180 days from the effective date of this Section in which to bring their facilities into compliance with the applicable provisions of this Section. Failure to comply with any applicable provision may result in revocation of the authority to operate.

(h) **Variances.** A variance from the time requirements of (e)(7) or (f)(1) of this Section may be granted by the District Manager or Manager of Field Operations for justifiable cause. A written request and supporting documentation is required. The District Manager or Manager of Field Operations shall respond in writing within five business days, either approving or disapproving the request.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 32 Ok Reg 767, eff.

8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-9-4. Commercial recycling facilities

(a) **Scope.** This Section shall cover the permitting, construction, operation, and closure requirements for commercial recycling facilities. A commercial recycling facility is a facility which is authorized by Commission order to recycle materials defined as "deleterious substances" in OAC 165:10-1-2. Such substances must undergo at least one treatment process and must be recycled into a marketable product for resale and/or have some beneficial use. This definition does not include the reuse of drilling mud (plug mud) which was previously utilized in drilling or plugging operations. This Section does not cover hydrocarbon recycling/reclaiming facilities (see OAC 165:10-8-1 through 165:10-8-11).

(b) **Application requirements for facilities to recycle flowback water.**

(1) **Who may apply.** The applicant for a commercial recycling facility shall be the owner of the land (or person having a written firm option to purchase the land at the time the application is filed) on which the proposed facility is to be located. If the land on which the proposed facility is to be located is leased, both the owner and lessee of the land shall be joint applicants.

(2) **Compliance with rules.** Before issuance of an order authorizing the commercial recycling facility, the applicant shall comply with Commission Rules of Practice OAC 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section. Subsequent to issuance of an order authorizing a commercial recycling facility and prior to commencing construction of such facility, the applicant is required to submit to the Conservation Division a recorded copy of a deed reflecting that the applicant owns the land which is to be used for the commercial recycling facility.

(3) **Exhibits.** Two complete sets of all exhibits which shall be relied upon by the applicant shall be submitted to the Pollution Abatement Department of the Commission, pursuant to OAC 165:5-7-35. Those exhibits shall include, but are not limited, to the following:

(A) A lithologic log of test borings, identifying the subsurface materials encountered and the depth at which groundwater was encountered pursuant to (d)(2)(D) of this Section.

(B) A topographic map of the commercial recycling facility site.

(C) The appropriate Soil Conservation Service (SCS) soil survey aerial photo and legend.

(D) A detailed drawing of the site, with complete construction plans drawn to scale by or under the supervision of a registered professional engineer.

(E) A plan for closure of the facility, which shall specifically state how all aspects of closure shall be accomplished, including volume and fate of liquids and solids, earthwork to close any pit(s) (including placement of stockpiled topsoil), and revegetation of the site.

(F) An itemization of projected hauling, closure, reclamation, maintenance, and monitoring costs.

(G) A plan for post-closure maintenance and monitoring which shall address maintenance of the site as well as monitoring and plugging of wells. Exemption from the plugging of monitor wells may be obtained upon written request and approval of the Manager of Pollution Abatement.

(H) A plan for operation which shall address the method(s) by which excess water will be disposed.

(c) **Application requirements for recycling facilities designed for deleterious substances other than flowback water.**

(1) **Who may apply.** The applicant for a commercial recycling facility shall be the owner of the land (or person having a written firm option to purchase the land at the time the application is filed) on which the

proposed facility is to be located. If the land on which the proposed facility is to be located is leased, both the owner and lessee of the land shall be joint applicants.

(2) **Compliance with rules.** Before issuance of an order authorizing the commercial recycling facility, the applicant shall comply with Commission Rules of Practice OAC 165:5-7-1, 165:5-7-35, 165:5-3-1, and this Section. Subsequent to issuance of an order authorizing a commercial recycling facility and prior to commencing construction of such facility, the applicant is required to submit to the Conservation Division a recorded copy of a deed reflecting that the applicant owns the land which is to be used for the commercial recycling facility.

(3) **Exhibits.** Two complete sets of all exhibits which shall be relied upon by the applicant shall be submitted to the Pollution Abatement Department of the Commission pursuant to OAC 165:5-7-35. Those exhibits shall include, but are not limited, to the following:

(A) A topographic map of the commercial recycling facility site.

(B) The appropriate Soil Conservation Service (SCS) soil survey aerial photo and legend.

(C) A detailed drawing of the site, with complete construction plans, which shall include, but not be limited to, the location of any pits, staging areas and storm water retention structures.

(D) A detailed description of the recycling process and the types of deleterious substances that will be recycled.

(E) A plan for closure of the facility, which shall specifically state how all aspects of closure shall be accomplished, including volume and disposition of liquids and solids, earthwork to close any pit(s) (including placement of any stockpiled topsoil), removal of all materials in staging areas, and revegetation of the site.

(F) An itemization of projected hauling, closure, reclamation, maintenance, and monitoring costs.

(G) A plan for post-closure maintenance and monitoring which shall address maintenance of the site as well as monitoring and plugging of wells. Exemption from the plugging of monitor wells may be obtained upon written request and approval of the Manager of Pollution Abatement.

(d) **Restrictions.**

(1) **Order required.** No commercial recycling facility shall be constructed, enlarged, reconstructed, or used without a Commission order.

(2) **Site limitations.**

(A) No commercial recycling facility shall be constructed or used unless an investigation of the soils, topography, geology, and hydrology conclusively shows that storage of deleterious substances and the recycling of such substances at the site will not be harmful to groundwater, surface water, soils, plants, or animals in the surrounding area. No commercial recycling facility shall be constructed or used on or in an abandoned mine, strip pit, quarry, canyon, or streambed.

(B) No commercial recycling facility shall be constructed or used on any site that is located within a 100-year flood plain.

(C) No commercial recycling facility shall be constructed or used within a wellhead protection area (WPA) as identified by the Wellhead Protection Program (42 USC Section 300h-7, Safe Drinking Water Act), or within one mile of a public water well for which the WPA has not been delineated.

(D) Pits shall not be constructed or used at flowback water recycling facilities unless it can be shown that there will be a minimum of 25 feet between the bottom of the pit(s) and the groundwater level. To ascertain this and to demonstrate the subsurface profile of the site, a minimum of three test borings (the exact number of locations to be determined by the Pollution Abatement Department) shall be drilled to a minimum depth of 25 feet below the proposed bottom(s) of the pit(s) and into the first free water encountered. Perched water tables are not

considered for the purposes of this subparagraph. Test borings need not extend deeper than 50 feet below the bottom(s) of the pit(s) if free water has not been encountered before that depth. All boreholes converted to monitor wells shall conform to (f)(14) of this Section. All boreholes not converted to monitor wells shall be plugged from top to bottom with bentonite, cement, and/or other method approved by the Pollution Abatement Department within 30 days of drilling completion.

(E) If pits are not used in the operation of a commercial recycling facility, the Manager of Pollution Abatement may require test borings to be drilled at the site if data from monitor well boring(s) is insufficient to properly evaluate the site.

(F) No commercial recycling facility that is to use pits with a capacity in excess of 50,000 barrels shall be constructed or used within the following distances from the city limits of an incorporated municipality unless previously authorized by Commission order:

(i) Three miles if population is 20,000 or less.

(ii) Five miles if population is greater than 20,000.

(3) **Means of water disposal.** No commercial recycling facility shall be constructed or used unless the operator can show that there will be an ongoing means of disposal of excess water pursuant to (b)(3)(H) of this Section.

(e) **Surety requirements.**

(1) **Agreement with Commission.** Any operator of a commercial recycling facility shall file with the Manager of Document Handling for the Conservation Division an agreement to properly close and reclaim the site in accordance with approved closure and reclamation procedures upon termination of recycling operations due to abandonment, shutdown, full pits, or other reason. The agreement shall be on forms available from the Conservation Division and shall be accompanied by surety. The agreement shall provide that if the Commission finds that the operator has failed or refused to close the facility or take remedial action as required by law and the rules of the Commission, the surety shall pay to the Commission the full amount of the operator's obligation up to the limit of the surety.

(2) **Surety amount and type.** The Commission shall establish the amount of surety in the order for the authority to construct, enlarge, or operate a commercial recycling facility. The amount of surety shall be based on factors such as dimensions of the facility and costs of closure, reclamation, monitoring, plugging of monitor wells, any pit closure, trucking of any deleterious substances, remediation, earth work, revegetation, etc. The amount may be subject to change for good cause. Upon approved closure of a facility, the Manager of Pollution Abatement may administratively reduce the surety requirement to an amount which would cover the cost of monitoring the site and plugging the monitor wells. Surety shall be maintained for as long as monitoring is required. The type of surety shall be a corporate surety bond, certificate of deposit, irrevocable letter of credit, or other type of surety approved for the facility by order of the Commission. Any type of surety that expires shall be renewed prior to 30 days before the expiration date.

(3) **Posting surety before permit is issued.** An operator shall post surety with the Commission on forms provided by the Manager of Document Handling before a construction permit is issued, pursuant to (f)(1) of this Section.

(f) **Construction requirements.**

(1) **Permit required.** Prior to constructing any commercial recycling facility, the facility operator shall obtain a permit from the Manager of Pollution Abatement. Application shall be made on Form 1014CR. For use of a commercial recycling facility without a permit, the facility operator may be fined up to $5,000.00.

(2) **Runoff water prohibited.** No runoff water from surrounding land surfaces shall be allowed to enter a commercial recycling facility.

(3) **Stockpiling of topsoil.** Prior to constructing any pit with a capacity in excess of 50,000 barrels utilized in a commercial recycling facility, all topsoil within the top twelve inches of soil on the site shall be stockpiled for use as the final cover at the time of closure. The topsoil may be stockpiled in the outside slopes of the berms, provided it is not used for structural purposes and can be readily distinguishable from other soil materials at the time of closure. In cases where topsoil is stockpiled in the berms, it shall be shown in the as-built drawings pursuant to (f)(16) of this Section.

(4) **Monitoring by engineer.** Construction of any pit(s) with a capacity in excess of 50,000 barrels shall be monitored by a registered professional engineer or an engineer-in-training working under the supervision of a registered professional engineer (RPE) to assure that approved design specifications and Commission rules are adhered to. A minimum of six on-site visits to the site shall be made: two pre-construction, two during the installation of the geomembrane liner, and two post-construction. At least the post-construction on-site visit shall be made by the RPE.

(5) **Maximum fluid depth.** Any pit utilized in a commercial recycling facility shall be constructed in accordance with the maximum fluid or sediment depth specified in the order authorizing the facility. Any pit shall have a minimum freeboard of three feet.

(6) **Maximum dimensions.** Any pit utilized in a commercial recycling facility shall not be constructed to dimensions greater than that approved in the order. Pit dimensions shall be measured at the maximum allowable fluid level.

(7) **Geomembrane liners.**

(A) Any pit utilized in a commercial recycling facility must contain a geomembrane liner. The geomembrane liner shall have a minimum thickness of 40 mil.

(B) Any geomembrane liner used in such pits shall be chemically compatible with the type of substances to be contained in the pit and shall have ultraviolet light protection.

(C) Any geomembrane liner shall be placed over a specially prepared, smooth, compacted surface void of sharp changes in elevation, rocks, clods, organic debris, or other objects.

(D) Any geomembrane liner shall be continuous, although it may include welded or extruded seams, and the liner must cover the bottom and interior sides of the pit entirely. Sewing of seams is prohibited. The edges shall be securely placed in a minimum twelve inch deep anchor trench around the perimeter of the pit.

(8) **Width of the crown.** The crown (top) of any berm of a pit with a capacity in excess of 50,000 barrels utilized in a commercial recycling facility shall be a minimum of eight feet in width.

(9) **Slopes.** The inside slope of any exterior berm (having fluid on one side) shall not be steeper than 3:1 (horizontal to vertical) and the outside slope 2.5:1. The slopes of any interior berm (having fluid on both sides) shall not be steeper than 3:1.

(10) **Earthwork compaction.** All earthwork for pits with a capacity in excess of 50,000 barrels shall be compacted to achieve a minimum 90% Standard Proctor Density and shall be applied in lifts where some method of bonding is achieved between lifts, with each lift not to exceed eight inches prior to compaction.

(11) **Pipe installation.** Any pipe, tinhorn, culvert, or conduit in the berm between two adjoining pits shall be placed so that there is a minimum of 36 inches between the top of the pipe, tinhorn, culvert, or conduit and the lowest point in the top of the berm separating the pits.

(12) **Splash pad.** All pits utilized in commercial recyling facilities which receive fluids directly from a truck shall have a splash pad at the point where fluids are received unless a waiver is obtained from the Manager of Pollution Abatement by showing that damage of the liner will not

occur. The pad must be constructed of materials and to the dimensions necessary to effectively prevent the liner from eroding.

(13) **Fluid level marker.** A minimum of one stationary fluid level marker shall be erected in each pit or cell as required by the Manager of Pollution Abatement. The marker shall be erected in a location within the pit or cell where it can be easily observed. The marker shall be of such design that the maximum fluid level at any time may be clearly identified. Details of the proposed marker installation shall be approved by the Manager of Pollution Abatement prior to installation. Markers shall be installed under the supervision of a registered professional engineer, licensed land surveyor, or other person approved by the Manager of Pollution Abatement prior to installation.

(14) **Monitor wells.** Monitor wells must be installed in conjunction with every commercial recycling facility as required by the Manager of Pollution Abatement. All pits utilized in commercial recycling facilities shall have a minimum of three monitor wells installed-one upgradient and two downgradient from the pit. The exact number and location of monitor wells shall be approved by the Pollution Abatement Department prior to installation. No monitor well shall be installed more than 250 feet from the toe of the outside berm of a pit, nor shall any existing water well be used as a monitor well unless approved by the Manager of Pollution Abatement. Monitor wells installed prior to the effective date of this Section may be accepted by the Manager of Pollution Abatement if it can be shown that they adequately monitor a site. All new monitor wells shall be drilled to a depth of at least ten feet below the top of the first free water encountered, and all monitor wells shall be drilled to a depth of at least ten feet below the base of any pit. All new monitor wells shall be drilled and completed by a licensed monitor well driller. If documentation is submitted to the Manager of Pollution Abatement prior to drilling the monitor wells to show that no free water will be encountered within 50 feet below the bottom of any pit, the Manager of Pollution Abatement may require that monitor wells be drilled to a lesser depth. All new monitor wells shall meet the requirements as set out in rules established by the Oklahoma Water Resources Board, in addition to the following requirements:

(A) A removable and lockable cap shall be placed on top of the casing. The cap shall remain locked at all times, except when the well is being sampled.

(B) Within 30 days of installation, specific completion information, a diagram of the locations and numerical labeling for all monitor wells shall be submitted to the Manager of Pollution Abatement.

(15) **Leachate collection system.** The commercial recycling facility operator may elect to install a leachate collection system in lieu of monitor wells if such system will adequately detect any leak from the facility. The plan for the leachate collection system must be approved by the Manager of Pollution Abatement prior to installation of the leachate collection system.

(16) **As-built drawing.** A detailed, as-built drawing of the facility and monitor wells or leachate collection system by or under the supervision of a registered professional engineer shall be submitted to the Manager of Pollution Abatement before operation of a facility utilizing pits with a capacity in excess of 50,000 barrels commences. Operators of facilities which do not utilize pits and facilities utilizing pit(s) with a capacity of 50,000 barrels or less shall submit to the Manager of Pollution Abatement as-built drawings prepared by a qualified expert before operation of such facilities commence.

(17) **Liner certification.** An affidavit signed by the person who was responsible for installing any pit liner, certifying that the liner meets minimum requirements and was installed in accordance with Commission rules, shall be submitted to the Manager of Pollution Abatement before operation

of the facility commences. Supporting documentation shall also be submitted, such as geomembrane liner specifications from the manufacturer.

(18) **Facility approval.** Acceptance of materials by a commercial recycling facility shall not commence until a representative of the Conservation Division has inspected and approved the facility.

(19) **Hydrologically sensitive areas.** If the proposed site is known to be located over a hydrologically sensitive area, in addition to the foregoing construction requirements, the additional requirements shall apply:

(A) The total depth of any pit shall not exceed eight feet, and the total designed fluid or sediment depth shall not exceed five feet.

(B) A minimum 60-mil geomembrane liner shall be required.

(C) The Manager of Pollution Abatement shall determine the minimum depth of all monitor wells.

(g) **Operation and maintenance requirements.**

(1) **Vegetative cover.** Vegetative cover shall be established on all areas of earthfill immediately after any pit construction or during the first planting season if pit construction is completed out of season. The cover shall be sufficient to protect those areas from soil erosion and shall be maintained.

(2) **Fencing.** All commercial recycling facilities shall be completely enclosed by a fence at least four feet in height. No livestock shall be allowed inside the fence.

(3) **Sign.** A waterproof sign bearing the name of the commercial recycling facility operator, legal description, most current order number, and emergency phone number shall be posted within 25 feet of the entrance gate to any commercial recycling facility and shall be readily visible.

(4) **Site security.** Acceptable materials can be received by a commercial recycling facility only when there is an attendant on duty. All sites shall be secured by a locked gate when an attendant is not on duty. A key or combination to the lock shall be provided to the appropriate Field Inspector for the purpose of carrying out inspections.

(5) **Fluid level.** Deleterious substances shall not be accepted into any pit unless the fluid level can be maintained at an elevation no higher than the maximum level of the fluid level marker.

(6) **Acceptable materials.**

(A) An operator of a commercial recycling facility shall accept for recycling only those materials defined as "deleterious substances" in OAC 165:10-1-2 and as authorized in the order for the facility. Such substances must undergo at least one treatment process and must be recycled into a marketable product for resale and/or have some beneficial use.

(B) A sample from each incoming load shall be collected, filtered (if necessary) and tested as required by Commission order.

(C) The date, volume, source (generator), type of material and test results of each load received shall be entered into a log book. Supporting documentation such as any chemical analyses or D.O.T. material safety data sheets concerning such loads shall also be maintained by the operator. The log book and supporting documentation shall be available for inspection by a representative of the Conservation Division of the Commission at all times. Log books and supporting documentation shall be kept for a minimum of five years after closure is completed.

(7) **Storage of deleterious substances.** A commercial recycling facility shall not store anything other than deleterious substances as defined in OAC 165:10-1-2 and as authorized in the order for the facility. The contents of each pit or cell at a facility shall be sampled and analyzed by the operator at least once every six months (during January and July) after operations commence. More frequent sampling may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Pollution Abatement Department representative shall be notified at least 24 hours in advance of sampling to allow the representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to procedures established by the Manager of Pollution Abatement.

(C) If requested by a representative of the Conservation Division, each composite sample shall be split and a sufficient portion (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(D) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(E) All composite samples must be analyzed for constituents as required by Commission order by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters may be required, as determined by the Manager of Pollution Abatement.

(F) A copy of each analysis shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(8) **Oil film.**

(A) No pit utilized in a commercial recycling facility shall contain an oil film covering more than one percent of the surface area of the pit.

(B) The protection of migratory birds shall be the responsibility of the operator. Therefore, the Conservation Division recommends that to prevent the loss of birds, oil films be removed, or the surface area of any pit be protected from access to birds. [See Advisory Notice in OAC 165:10-7-3(c)].

(9) **Aesthetics.** All commercial recycling facilities shall be maintained so that there is no junk iron or cable, oil or chemical drums, paint cans, domestic trash, or debris on the premises.

(10) **Structural integrity.** All pits utilized in commercial recycling facilities shall be used, operated, and maintained at all times so as to prevent the escape of their contents. All erosion, cracking, sloughing, settling, animal burrows, or other condition that threatens the structural stability of any earthfill shall be repaired immediately upon discovery.

(11) **Monitor well and leachate collection system sampling.** Sampling of monitor wells or leachate collection systems shall begin prior to accepting any deleterious substances into a new facility and within 30 days of completing the drilling of monitor wells or installation of leachate collection systems on existing facilities, and sampling shall be done at least once every six months (during January and July) after operations commence until three years after closure is completed. Sampling of greater frequency or duration may be required by the Manager of Pollution Abatement. The following procedures shall be used:

(A) The appropriate Field Inspector shall be notified at least 24 hours in advance of sampling to allow a Commission representative an opportunity to witness the sampling.

(B) Samples shall be collected and handled by the operator according to EPA-approved standards. (RCRA Groundwater Monitoring Technical Enforcement Guidance Document, EPA, OSWER-9950.1, September 1986, pp. 99-107.)

(C) If requested by a representative of the Conservation Division, a sufficient portion of each sample (approximately one pint) shall be properly labeled and delivered or otherwise provided to the appropriate Conservation Division District Office or Field Inspector.

(D) All samples delivered to the laboratory shall be accompanied by a chain of custody form.

(E) All samples must be analyzed for pH and chlorides by a laboratory certified by the Oklahoma Department of Environmental Quality or operated by the State of Oklahoma. Analysis of additional parameters

may be required based on the operation of the facility as determined by the Manager of Pollution Abatement.

(F) A copy of each analysis and a statement as to the depth to groundwater encountered in each well or leachate collection system, or a written statement that no water was encountered, shall be forwarded to the Pollution Abatement Department within 30 days of sampling.

(G) Monitor wells shall be plugged in accordance with Oklahoma Water Resources Board rules.

(12) **Prevention of pollution.** All commercial recycling facilities shall be used, operated, and maintained at all times so as to prevent pollution. In the event of a nonpermitted discharge at or from a commercial recycling facility, sufficient measures shall be taken to stop or control the loss of materials, and reporting procedures in 165:10-7-5(c) shall be followed. Any materials lost due to such discharge shall be cleaned up as directed by a representative of the Conservation Division. For a willful non-permitted discharge, the commercial recycling facility operator may be fined up to $5,000.00.

(h) **Semiannual report.** The operator of any commercial recycling facility shall submit a report on Form 1014A to the Manager of Pollution Abatement by February 1 and August 1 of each year.

(i) **Closure requirements.**

(1) **Notification.** The Manager of Pollution Abatement shall be notified in writing whenever a commercial recycling facility becomes inactive, is abandoned, or operation of the facility ceases for any reason. A commercial recycling facility may be considered to be inactive by the Commission if:

(A) The facility has been shut down by the Commission because of a violation which results in the filing of an application for an order to vacate the operator's authority.

(B) The operator is unable to furnish documentation to show that there has been receipt of deleterious substances to be recycled at the facility during the previous twelve months.

(C) The authority to operate the facility has been terminated by failure to comply with (k) of this Section.

(2) **Time limit.** Closure of all commercial recycling facilities shall be commenced within 60 days and completed within one year of cessation of operations, pursuant to (1) of this subsection. In cases where extenuating circumstances arise, one extension of six months may be administratively approved in writing by the Manager of Pollution Abatement. Closure shall be in accordance with an approved closure plan. A progress report shall be submitted to the Manager of Pollution Abatement, every three months (during January, April, July, and October) after cessation of operations until closure is completed.

(3) **Restrictive covenant.** The Manager of Pollution Abatement may require a restrictive covenant to be filed with the County Clerk of the county in which a commercial recycling facility is located. The document shall accurately describe the facility location and shall specifically restrict the current or future landowners of the site from puncturing the final cover of any pit utilized in a commercial recycling facility or otherwise disturbing the site to the extent that pollution could occur.

(4) **Penalty for failure to meet closure requirements.** An operator failing to meet the closure requirements set out in this subsection may be fined up to $1,000.00.

(j) **Additional requirements.** The requirements set forth in this Section are minimum requirements. Additional requirements may be made upon a showing of good cause that an operator has a history of complaints for failure to comply with Commission rules and regulations, the site has certain limitations, or other conditions of risk exist.

(k) **Application to existing facilities.** Operators of facilities permitted or ordered prior to the effective date of this Section must either comply with

subsections (a), (d)(1), (e), (f)(2), (f)(11), (f)(12), (f)(13), (f)(14), (f)(15), (g), (h), (i), (j) and (m) of this Section or close such facilities within one (1) year of the effective date of this Section. All commercial recycling facilities permitted, but yet to be constructed as of the effective date of this Section, shall also be subject to all of the construction requirements in subsection (f) of this Section.

(l) **Variances.** Except as otherwise provided in this Section, variances from provisions of this Section may be granted for good cause by order after application, notice, and hearing.

(m) **Compliance history.** In the event the Commission has evidence that an applicant for a commercial recycling facility may not possess a satisfactory compliance history with Commission rules, the Director of the Conservation Division may seek an order of the Commission, issued after application, notice, and hearing, determining whether the applicant should be authorized to operate such a facility.

[**Source:** Added at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

SUBCHAPTER 10. BROWNFIELD PROGRAM

165:10-10-1. Purpose, authority and applicability

(a) **Purpose.** The purpose of the Brownfield program is to provide for the safe reuse of Brownfield properties and provide a mechanism for landowners to resolve or manage their environmental liability to the government.

(b) **Authority.** The Brownfield Program implemented under Okla. Stat. Tit. 27A §§1-3-101(E)(1)(j), 1-3-101 (E)(2) and 1-3-101 (E)(5); Okla. Stat. Tit. 17 §§52(A)(1)(j), 52(A)(2) and 52(A)(5) and Okla. Stat. Tit. 52 §§139(B)(1)(j), 139(B)(2) and 139(B)(5), as authorized and funded by the federal Environmental Protection Agency (EPA).

(c) **Applicability.** Any person who qualifies under OAC 165:10-10-2 and 165:10-10-4 may participate in the Brownfield program and receive a Certificate of Completion or a Certificate of No Action Necessary upon successful completion of the Brownfield process.

[**SOURCE:** Added at 25 OK Reg 2187, eff. 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-2. Brownfield defined

(a) A "Brownfield" is a real property (site) where expansion, redevelopment, normal use or reuse may be complicated by the presence or potential presence of a deleterious substance, pollutant, or contaminant. This includes land that is contaminated by petroleum, petroleum products, and related wastes, including crude, condensate, gasoline and diesel fuel, produced water/brine, glycol and/or drilling mud. A proposed Brownfield site is a defined area; it does not need to be the entire property or lease.

(b) Sites excluded from program participation are:

(1) Sites controlled by responsible parties (RPs);

(2) Sites listed on the National Priorities List (NPL) maintained by EPA;

(3) Sites subject to order or consent decree under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund;

(4) Sites permitted under certain federal programs including the Resource Conservation and Recovery Act (RCRA), CERCLA, the Toxic Substances Control Act (TSCA), or the Safe Drinking Water Act (SDWA);

(5) Lands where closure of the remediation process has been approved by or where a closure plan concerning remediation has already been submitted to the Commission;

(6) Sites owned or under the control of the federal government;

(7) Portions of sites with PCB (polychlorinated biphenyls) pollution

subject to remediation under TSCA;

(8) Portions of facilities with an approved or ongoing federal Leaking Underground Storage Tank (LUST) Fund remediation; however the Oklahoma LUST fund and the Oklahoma Petroleum Storage Tank (PST) Indemnity fund are potentially available for assessing and cleaning up newly listed PST Brownfield sites in Oklahoma.

(c) Responsible party (RP) and other ineligible parties defined. A person, corporation, company, non-profit organization, or any other entity that:

(1) Caused the pollution at the proposed Brownfield site or knew about the pollution and allowed it to occur; or

(2) Contributed to already existing pollution at the site; or

(3) Hindered or otherwise knowingly attempted to obstruct efforts to perform environmental assessments of or to remediate pollution caused by an RP at the site; or

(4) Is not in compliance with a final agency order or any final order or judgment of a court of record secured by any state or federal agency for any of the responsible party's actions at the site which could have led to a leak, spill, and/or other cause of the pollution in violation of agency rules, or

(5) Has demonstrated a pattern of uncorrected noncompliance with state or federal environmental laws or rules; or

(6) Has past operations at the site and/or at other sites that indicate a reckless disregard for the protection of human health and safety or the environment.

[**SOURCE:** Added at 25 OK Reg 2187, eff. 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-3. Administration and enforcement of rules

(a) The Manager of Pollution Abatement and the Brownfield program staff shall supervise and coordinate the administration and enforcement of the rules of this Subchapter under the direction of the Director of Oil and Gas Conservation and the Commission.

(b) The primary goal of the implementation of Brownfield site assessments and remediation projects shall be the protection and/or restoration of the beneficial use of the land, the soil and any surface or subsurface waters of the State adversely impacted or impaired by pollution from a Commission regulated Brownfield site.

(c) Site assessments and remediation projects conducted under the supervision and coordination of the Manager of Pollution Abatement and/or Pollution Abatement/UIC/Brownfield staff shall adhere to the general practices appearing in the Oil and Gas Conservation Division's Guardian Guidance document for petroleum and produced water site assessment and remediation oversight, enforcement, approval and verification including the Guidelines and Numerical Criteria for New or Historic Produced Water/Brine Spills.

(d) Applicant may request in writing, and the Manager of Pollution Abatement may grant, an administrative exception to a Commission Brownfield rule if applicant can demonstrate that:

(1) Requirements in pertinent state laws and federal Brownfield rules and laws are still met, and

(2) The exception will protect human health, safety and the environment and the beneficial use of the land at least as well as strict adherence to the Commission Brownfield rule.

[**SOURCE:** Added at 25 OK Reg 2187, eff. 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-4. Determination of Brownfield eligibility

(a) **Applicant eligibility.** An applicant may be any non-responsible party (non-RP) including:

(1) The legal owner in fee simple, the tenant or lessee of the property, or a person who has a written firm option to purchase or operate the property at the time the application is filed and who has the ability to implement a redevelopment proposal, if needed, once site assessment and/or remediation is complete;
(2) Any person who acquired the ownership, operation, management, or control of the site through foreclosure or under the terms of a bona fide security interest in a mortgage or lien on, or an extension of credit for the property, or foreclosed on the property, or received an assignment or deed instead of foreclosure or some other indicia of ownership and thereby becomes the owner of the property;
(3) An agency, non-profit organization or other entity who chooses to clean up or otherwise rehabilitate a property for the owner or tenant in order for it to be returned to productive use or become green space;
(4) The Oklahoma Energy Resources Board (OERB), regarding sites in its surface restoration program which meet the definition of a Brownfield property appearing in OAC 165:10-10-2. There is no requirement that OERB sites be designated as Brownfield sites, or
(5) A non-RP who wishes to restore property for a potential or known RP. If an entity that is not the RP wants to apply to the Brownfield program and is accepted and completes the process, such a site would be granted limited liability protection.

(b) **Eligibility of site.** The following conditions must be met and information provided to be considered for eligibility as a Brownfield site:
(1) Any facility or real property where normal use, reuse, expansion or redevelopment is hindered by pollution or suspected pollution of a substance or substances caused by releases from activities regulated by the Commission may qualify as a Brownfield site.
(2) The applicant will need to provide an Applicant Eligibility form with the following information included on the form:
(A) A physical address for the land or property;
(B) A legal description of the land or property;
(C) Driving directions from nearest major intersection.
(3) A site survey by a surveyor, or a site plan containing global positioning system (GPS) coordinates made under the supervision of a qualified environmental professional defining the area to be addressed must be submitted for each Brownfield site once it is accepted into the program.

(c) **Determination of eligibility.** The Commission's Brownfield staff will determine the initial eligibility for any allegedly contaminated portion of a Brownfield project. Brownfield staff will determine to the extent possible:
(1) If the site is a relatively low risk site, compared to all types of pollution sites;
(2) If any funds have already been spent on the site, and the source of any such funds;
(3) If there are any viable responsible parties. Commission records will be checked by Commission staff for all Brownfield sites; and
(4) Whether the current or immediate past owner and/or operator of the site caused or made the pollution worse and whether such parties took reasonable corrective steps with regard to any pollution.

[**SOURCE:** Added at 25 OK Reg 2187, eff. 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-5. The Commission's Brownfield program process

(a) **Pre-application informational exchange.** The applicant may want to consider a pre-application conference by telephone, e-mail, mail, or in person with Brownfield staff. During the pre-application conference the applicant will be advised about what information is necessary in order for Brownfield staff to determine whether the applicant and the applicant's site are eligible for the Brownfield program.

(b) **Brownfield eligibility determination.** All applicants and properties must meet federal and state Brownfield eligibility requirements. Commission standards and practices in effect at the time the application is filed will also be considered in determining whether eligibility requirements have been satisfied.

(c) **Brownfield program application.**

(1) Applicants for the Brownfield program, except for sites submitted by Commission field inspectors, will be required to submit an Application for Brownfield Program Eligibility form, an Application for Brownfield Site Eligibility and Assessment form and any required documentation to show they are eligible.

(2) The OERB Voluntary Environmental Program has sole discretion in determining whether it is to apply to the Commission's Brownfield program regarding abandoned exploration and production (E & P) sites which have been submitted to the OERB for consideration under its program which is limited to surface restoration. The site must meet the definition of a Brownfield property in OAC 165:10-10-2.

(3) When a non-RP wants to apply to remediate a property under the Brownfield program, the applicant must certify by affidavit that it owns the property or has a current lease or easement which is given to accomplish the remediation, or if it does not, has provided legal notice to the property owner of applicant's desire to remediate the site.

(4) Applicant must notify the Brownfield staff in writing of any litigation the Applicant has knowledge of concerning the site which has concluded or is pending, and any information concerning outstanding judgments, liens, tax levies, etc. filed of record at the time the application is filed or which is filed after applicant submits its application to the Commission and prior to final Commission action regarding the site.

(5) Completed applications must be sent to the following address: Oklahoma Corporation Commission, Oil and Gas Conservation Division, Brownfield Program, P.O. Box 52000, Oklahoma City, OK 73152-2000.

(d) **Notification of application status.** Subsequent to acceptance of an application, Brownfield staff will issue a letter to the applicant adding the site to the Brownfield site list (requirements for this list are in 165:10-10-7). If an application is denied by Brownfield staff, staff will promptly provide applicant with a written statement of the reasons for such denial.

(e) **Site assessments and/or remediation.** Refer to 165:10-10-9.

(f) **Public participation.** Refer to 165:10-10-10 through 165:10-10-11.

(g) **Brownfield site closure.** Refer to 165:10-10-12 and 165:10-10-14.

(h) **Brownfield Certificates.** Refer to 165:10-10-13.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-6. Eligibility of site [REVOKED]

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Revoked at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-7. The Commission's Brownfield site list

(a) The Commission is required by federal statutes to maintain a current list of every site which has qualified as a Brownfield site, including those sites on which work has been completed. The list shall be made available to the public on the Commission's website.

(b) Each site on the Brownfield sites list will include:

(1) Site name;

(2) Address or legal description of the site;

(3) Town, city, and county of the site;

(4) Site level of progress;

(5) Allowable use of revitalized land.

(c) Brownfield staff will be responsible for maintaining and updating the public record of sites that have qualified for the Commission's Brownfield Program.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-8. Processing of Brownfields application [REVOKED]

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Revoked at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-9. Assessment and remediation of site

(a) **Qualifications.** All Brownfield assessment and remediation projects will be overseen by a qualified environmental professional, defined by EPA as someone who possesses sufficient specific education, training, and experience necessary to exercise professional judgment to develop opinions and conclusions regarding conditions indicative of releases or threatened releases of deleterious substances on, at, in, or to a property, sufficient to meet the objectives and performance factors of the EPA's All Appropriate Inquiries rule (40 CFR Part 312) and ASTM E1527-05. Qualified environmental professionals must have one of the following:

(1) A state or tribal issued certification or license (including Professional Engineer, Professional Geologist, and PST Division of the Corporation Commission licensed Remediation Consultant) and three years of relevant full-time work experience; or

(2) A Baccalaureate or higher degree in science or engineering, including geologists as defined in 25 O.S. § 35 and engineers as defined in 59 O.S. § 475.1 et seq., and five years of relevant full-time work experience; or

(3) Ten years of relevant full-time work experience.

(4) Individuals who do not meet the above requirements must work under the supervision or responsible charge of an individual who meets the requirements for an environmental professional.

(b) **Assessments.**

(1) The appropriate Commission staff may conduct initial site inspections to evaluate and recommend those sites that qualify for the Brownfield program; Brownfield staff will approve inspections and assessments and list each approved site in the database.

(2) Qualified environmental professionals will perform an assessment (Phase I and/or Phase II) of each property.

(3) Governmental entities, quasi-governmental entities, and non-profit organizations may be eligible for a Targeted Brownfield Assessment (TBA) conducted by either the Commission or EPA.

(4) OERB's qualified staff or contractor may perform assessments on abandoned exploration and production (E&P) sites.

(5) Assessments of former retail petroleum storage tank sites will be overseen by and coordinated with the Commission's PST Division staff.

(6) EPA's All Appropriate Inquiry (AAI) Rule appearing in 40 CFR Part 312 shall be complied with as per the Commission's guidance.

(7) If during an initial investigation or Phase I or Phase II assessment pollution is discovered and immediately removed from the site, as confirmed with sample analytical results, the site may qualify for No Further Action (NFA) status.

(c) **Phase I.** Basic site and assessment information is necessary for exploration, production, and/or pipeline sites known or suspected to be contaminated by substances defined in OAC 165:10-10-2(a), and for PST sites. Initial site assessment information includes, but is not limited to:

(1) Analyses from one or more soil and water background samples;

(2) A certified survey or the results of a GPS survey defining the area of pollution,

(3) The present and proposed uses of the site;

(4) The operational history of the site and current use of areas contiguous to the site; and

(5) Detailed historical and records reviews as per AAI, which may be waived by Brownfield staff until after the basic physical environmental/pollution assessment is completed and Commission staff concludes its review of sample data pertaining to the site.

(6) A Category Index Table must be submitted for all oil and gas and pipeline sites likely or definitely polluted above action levels. The Category Index Table appears in the Commission's Guardian Guidance document, which is available on the Commission's website or by request.

(7) Sites that are determined by the Brownfield staff to need no remediation following an acceptable Phase I assessment can be issued no action necessary certification once the Brownfield staff receives appropriate documentation.

(d) **Phase II.** Phase II sites are those sites where the Phase I assessment demonstrates the need for additional assessment, action level determination, and (often) remediation guidance.

(1) Phase II oil and gas sites and pipeline (crude and refined product and produced water) sites will be overseen by the Oil and Gas Conservation Division's Brownfield staff;

(2) Phase II retail petroleum storage tank sites will be referred to the Commission's PST Division and will adhere to the Oklahoma Risk-Based Corrective Action guidelines for assessment and remediation;

(3) Necessary information generally includes but is not limited to concentrations of pollutants in the soils, surface water or groundwater at the site; the vertical and horizontal extent of pollution in the soils, surface water or groundwater at the site; a determination that risk based criteria to protect human health and the environment at and around the site are or are not being met; and recommendations on how to meet risk based criteria, including remediation as needed;

(4) Sites that are determined by the Brownfield staff to need no remediation following appropriate environmental and risk assessment can be issued no action necessary certificates once the Brownfield staff receives appropriate documentation.

(e) **Status of site when no action is necessary.**

(1) A no action necessary determination is appropriate for a site if at the conclusion of the initial inspection, TBA, Phase I or Phase II investigation, or subsequent to the immediate removal of pollution from a site, the Brownfield staff or other appropriate Commission staff finds or concurs that the site poses no significant risk to human health or safety or the environment according to the proposed use of the site.

(2) Brownfield staff will issue a no action necessary certificate when the site is restored for beneficial use and other required program elements, if any, are completed.

(f) **When pollution is likely present or is present above action levels.** If pollution is likely present or is present above action levels at a site, further assessment and remediation will adhere to one of the following regimens:

(1) The Oil and Gas Conservation Division's Guardian Guidance document and rules for petroleum and produced water site assessment and remediation oversight, enforcement, approval and verification; or

(2) The PST Division's guidance document and rules for site assessment and cleanup oversight, enforcement, approvals and verification; or

(3) For E&P sites where there is no RP, the OERB Voluntary Environmental Program may, in its sole discretion, submit to the Commission's Brownfield program those abandoned E & P sites which have qualified for the OERB's program, which is limited to surface restoration in order that such sites may be assessed and remediated by OERB in accordance with the Commission's Brownfield rules; and

(4) The Commission's Brownfield staff will act as the regulator for the Brownfield program and ensure that applicable Brownfield laws and rules are followed.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-10. Notice

(a) **Public notice.** Public notice is necessary for remediation sites (Phase II sites requiring remediation or cleanup). The applicant must provide public notice that its proposal regarding the site is ready for public review. The notice must be published one time in newspapers of general circulation published in Oklahoma County, Oklahoma, and in a newspaper of general circulation published in each county where the lands that are the subject of the application are located. The applicant shall also submit the notice to the Brownfield staff for posting on the Commission's website. The notice must contain the:

(1) Name and address of the location where the application and related documentation, including any proposed remediation plan, may be reviewed, in addition to the days of the week and hours during which such information may be reviewed;

(2) Applicant's name, mailing address, telephone number, email address and contact person, as well as the Commission's mailing address and a telephone number and email address of a contact person at the Commission;

(3) Name, address and legal description of the Brownfield site;

(4) Purpose of the notice;

(5) Description of the proposed cleanup, monitored natural attenuation, institutional control, and/or other remedial action being sought;

(6) Other pertinent information required by Brownfield staff and rules;

(7) Other information the applicant may deem relevant; and

(8) Time period of at least thirty (30) days after the notice is published for the submission of written public comments and written requests for a public meeting regarding the site, in addition to the mailing address and e-mail address to which public comments and requests for public meetings can be sent, the name of a contact person and any facsimile numbers, if available. The notice must also provide that any written public comments and requests for a public meeting are to be sent to the Oklahoma Corporation Commission, Oil and Gas Conservation Division, Brownfield Program, P.O. Box 52000, Oklahoma City, Oklahoma, 73152-2000.

(b) **Public meeting.**

(1) If the Commission receives a timely written request for a public meeting, if the Commission determines there is a significant degree of public interest in the site remediation proposal and the action being sought, or if the applicant chooses to have a public meeting, then the applicant must publish notice of the date, time and address of a public meeting at least thirty (30) days prior to the meeting in the manner described in paragraph (a), above, and include in the notice the information appearing in paragraphs (a)(1) through (a) (8), above.

(2) The notice must provide for a time period of at least thirty (30) days after the notice is published for the submission of written public comments, and that verbal comments may be made at the meeting. The mailing address and e-mail address to which public comments can be sent, the name of a contact person and any facsimile numbers, if available, must also be included in the notice. The notice must also provide that any written public comments are to be sent to the Oklahoma Corporation Commission, Oil and Gas Conservation Division, Brownfield Program, P.O. Box 52000, Oklahoma City, Oklahoma, 73152-2000.

(3) The public meeting will be held in a convenient location near the proposed Brownfield site.

(c) **Publisher's affidavits.** The applicant is required to provide to the Brownfield staff the publisher's affidavits regarding the public notice for comments and/or a public meeting within twenty (20) days after the date(s) of publication;
(d) **When public notice is not required.** Applicant is not required to publish a notice regarding those sites Brownfield staff or other appropriate Commission staff find or concurs need no further action after staff's review of applicant's site assessment information or which are remediated for the applicant by a responsible party.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-11. Public meetings and public comments
(a) The format for each public meeting will be established by the Commission's Brownfield staff or its Public Information Staff, and the Commission's Brownfield staff or its Public Information Staff will moderate each public meeting;
(b) The moderator may set reasonable time limits for speakers, and the moderator may extend the time for public comment at the conclusion of the public meeting;
(c) Anyone may provide public comments or submit a written statement and data regarding the remediation proposal at any public meeting;
(d) The applicant or its representative must be available at each public meeting in order to answer questions;
(e) If the Commission receives no request for a public meeting, and the Commission deems no public meeting necessary, and no public comments are received, then the Commission will proceed with the applicable determination; and
(f) If the Commission receives public comments, the appropriate Brownfield staff will prepare a written response to such comments within sixty (60) days after the close of the comment period.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-12. Closures of Brownfield sites
(a) **Final surface remediation confirmation.**
(1) A qualified environmental professional for the applicant and/or the Brownfield, other Oil & Gas, or PST staff of the Commission, or the OERB, if such entity is involved with the site, will perform a closure survey, which may include but is not limited to visual observations and sampling the soil, surface water and/or groundwater at the site to confirm the project is completed and the property is ready for its proposed use; and
(2) The results of the closure survey, including any soil, surface water and/or groundwater sample results, must be submitted to appropriate Commission and Brownfield staff, and the appropriate regulatory program will confirm if cleanup standards have been met.
(b) **Final documentation.**
(1) The applicant is required to submit all necessary documentation regarding the site to Brownfield staff.
(2) The Brownfield staff will review, as required by applicable laws and rules, the work performed on the site as reflected in the documentation filed by Applicant.
(3) The applicant shall submit to Brownfield staff recorded copies of documents confirming that any deed restrictions or other institutional controls have been filed with the appropriate authorities.
(c) **Request for closure.** The applicant shall request closure of the site after all reviews have been completed by applicable Commission staff members and the site is found by Commission staff to be in compliance with all the

Brownfield and regulatory laws and rules.
(d) **Records of sites.** The Brownfield staff will maintain a public record of each site that has qualified for the Brownfield program for a period of three (3) years. After the three (3) year period has expired the records will be archived.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-13. Commission Brownfield certificates issued
(a) A "No Action Necessary" Certificate shall be issued to applicant by the Commission when the Commission has made such determination.
(b) A "Certificate of Completion" will be issued by the Commission for remediated sites after the closure survey of the site and review of the project has been approved by the Commission.
(c) The Certificates will state whether or not any continuing care of structural institutional controls, or any long term monitoring of the site, is to occur after issuance of any Certificate.
(d) All Brownfield Certificates issued by the Commission must be filed by the applicant in the office of the county clerk in the county where the Brownfield site is located. The Applicant is required to provide a copy of the Certificate reflecting that it has been recorded with the county clerk's office both to the landowner of the subject site and to the Brownfield staff within thirty (30) days after the Certificate has been filed.
(e) Applicant's submission of any false or materially misleading information to the Commission in conjunction with its application shall render voidable any of the Certificates discussed above.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-10-14. Responsible party closures (for remedial actions)
An RP that is legally responsible for the remediation of the pollution at a site is not eligible for the Commission's Brownfield Program, but can request that a standard case closed letter be issued by the appropriate Commission Department reflecting that the necessary work at the site has been completed and that the case has been closed by such Department.

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

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SUBCHAPTER 11. PLUGGING AND ABANDONMENT

165:10-11-1. License for pulling pipe and plugging wells

(a) No person shall contract to pull casing or plug oil, gas, injection, disposal, or other service wells, or contract to salvage casing therefrom, or purchase wells for the purpose of salvaging casing therefrom until a license has been secured from the Commission.

(1) The application for such license shall state:

(A) The name of the applicant.

(B) The names and addresses of all partners, chief officers, and directors.

(C) The experience of applicant.

(D) Evidence of financial responsibility of the applicant.

(E) The counties in which the applicant will operate.

(2) Notice that an application has been filed shall be published by the applicant in a newspaper of general circulation in Oklahoma County and in the county where the applicant's principal place of business is located. The applicant shall file proof of publication prior to the hearing or administrative approval. The notice shall include:

(A) The name of the applicant.

(B) Generally what operations the applicant intends to conduct for which applicant is financially responsible.

(C) The counties in which applicant will operate.

(3) If a written objection to the application is filed within 15 days after the application is published or if a hearing is required by the Commission, the application shall be set for hearing and notice thereof shall be given as the Commission shall direct. If no objection is filed and the Commission does not require a hearing, the matter shall be presented administratively to the Manager of Field Operations who shall file a report and make recommendations to the Commission.

(b) The license shall not be transferable and may at any time be revoked by the Commission upon complaint, notice, and hearing.

(c) Any person violating this Section may be fined up to $2,500.00. Any operation in violation of this Section shall be shut down pending compliance with this Section.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-2. Operating requirements for licensees

(a) This Section shall apply to each licensee under 165:10-11-1.

(b) If a licensee prepares the Notice of Intent to Plug (Form 1001 and/or the Plugging Report (Form 1003), then the licensee shall:

(1) Include the following on any submitted form:

(A) The name and address of the well operator if the licensee is serving as a contractor for the operator of the well.
(B) The name and address of the person or entity hiring the licensee if the licensee is serving as the contractor for any person who is not an operator of the well.
(C) That he is acting independently if the licensee either purchased the well for salvage or contracted with the landowner to plug the well in exchange for casing and/or other well equipment.

(2) Mail a copy of Form 1001 to the last known operator of the well to be plugged, as shown by the records of the Conservation Division.

(c) For purposes of this subsection, the term "plugged well" shall refer to a well for which the Conservation Division has a plugging record. A licensee shall comply with the requirements of 165:10-1-10 and 165:10-3-1 before entering a plugged well if:

(1) The licensee is not hired by the operator of the well to conduct the re-entry operation.
(2) The owner of the well is either the licensee or the surface owner of the tract on which the well was drilled.
(3) The Commission has not contracted with the licensee to replug the well.

(d) A licensee shall be responsible for the plugging of a well if:

(1) The licensee is the owner of the well or the licensee is the operator of the well.
(2) The licensee enters a well without having contracted with the operator or with a party other than the operator who has authority to authorize the licensee to enter the well on behalf of such party.

(e) Any violation of this Section will subject licensee to a fine, to suspension or revocation of licensee's license issued pursuant to 165:10-11-1, and to proceedings as authorized by statute in the district court.

[**SOURCE:** Amended in Rule Making 97000002, eff 7-1-97]

165:10-11-3. Duty to plug and abandon

(a) **Scope.** This Section applies to:

(1) Liability of the well owners and operator or other responsible person(s) to plug a well.
(2) Time periods for plugging wells:
(A) Without casing.
(B) With only surface casing and cement.
(C) With production casing.
(3) Wells exempted from plugging.
(4) Notice of Temporary Exemption from Plugging granting permission to postpone plugging of a well.

(b) **Liability of owners and operators or other responsible persons(s).** Any working interest owner and operator of any oil, gas, disposal, injection, or other service well or any seismic, core, or other exploratory hole, whether cased or uncased, shall be jointly and severally liable and responsible for the plugging thereof in accordance with this Subchapter unless other responsible person(s) become liable for such plugging. "Other responsible person(s)" means person(s) exercising dominion and control over any oil, gas, disposal, injection, or other service well or any seismic, core, or other exploratory hole, whether cased or uncased, without the authority or permission of the working interest owners or operator thereof. In such instances the other responsible person(s) shall be jointly and severally liable with the owners and operator for the plugging of the well. The owner of the surface estate shall not be considered an "other responsible person" solely as a result of:

(1) the reversion of the ownership of an abandoned wellbore and associated equipment to the surface owner, as a matter of law, unless the surface owner engages in activities that potentially compromise the integrity of the wellbore; or

(2) the removal of abandoned surface equipment, trash and debris from the surface estate, or remediation activities regarding the surface estate.

(c) **Time period for plugging well without casing.** Each well in which neither production casing nor surface casing has been run shall be properly plugged within 72 hours after drilling or testing is completed. However, should the lack of production and surface casing create a fire hazard or a risk of contaminating the environment or formations containing oil, gas, or known treatable water, said well shall be properly plugged within 24 hours after drilling and testing is completed. The well marker requirement described in 165:10-3-4 (e) shall be followed.

(d) **Time period for plugging well with only surface casing and cement.** Each well in which only surface casing has been run and cemented in conformance with 165:10-3-4 shall be properly plugged within 90 days after drilling or testing is completed unless the lack of production or intermediate casing creates a fire hazard or risk of contaminating the environment or formations containing oil, gas, or known treatable water, in which case or cases the well shall be plugged within 24 hours.

(e) **Time period for plugging well with production casing.** Unless exempted under provisions contained elsewhere in this Section, any well which has production casing in place shall be plugged within one year after the latter of:

(1) Cessation of drilling if the well was not completed or tested; or

(2) Cessation of the latter of completion or testing if the well has not produced; or

(3) Cessation of production.

(f) **Operators failing to commence timely plugging operations.** An operator_who fails to commence plugging operations as required in (c), (d), and (e) of this Section after due notice from the District Office or the appropriate field inspector may be fined up to $1,000.00.

(g) **Wells exempted from plugging.** The following wells which have production casing in place shall be exempt from (e) of this Section:

(1) Shut-in gas wells, for the purpose of this Section, shall be considered producing wells in operation.

(2) Any well for which a written order of the Commission granting a specific exception to plugging is in full force and effect.

(3) Supply wells or wells authorized by order of the Commission for injection or disposal purposes and are in compliance with the rules of the Commission.

(4) Any well for which a temporary exemption from the plugging rules has been approved.

(5) Any oil or gas well which is exempt from plugging pursuant to 17 O.S. § 53.

[**SOURCE:** Amended at 9 Ok Reg 2295; Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000035, eff 7-1-99; Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019)]

165:10-11-4. Notification and witnessing of plugging

(a) **Wells without production casing.** The appropriate Conservation Division District Office shall be notified at least 12 hours prior to commencement of plugging operations and a plugging procedure agreed upon for any well without production casing. Each plugging operation may be witnessed by an authorized representative of the Conservation Division.

(b) **Wells with production casing.** A separate Notification of Intention to Plug (Form 1001) for each well with production casing shall be filed with the appropriate Conservation Division District Office at least five days prior to the commencement of plugging operations. The five day notice requirement may be reduced or waived:

(1) If a qualified representative of the Conservation Division is available to witness the plugging operation.

(2) At the discretion of the District Manager of the District in which the well is located or his supervisor.

(c) **Expiration.**

(1) **Ninety-day period.** The Notification of Intention to Plug (Form 1001) shall expire ninety days after it is filed with the appropriate Conservation Division District Office, unless plugging operations are commenced and thereafter continued with due diligence to completion.

(2) **Thirty-day extension.** A thirty day extension of the Notification of Intention to Plug may be granted providing the Conservation Division staff determines that no material change of condition has occurred, if written request for the extension is received prior to the expiration date of the original Notification of Intention to Plug. Only one extension may be granted.

(d) **Penalty.** An operator or licensed plugger plugging a well without notifying and agreeing on a plugging procedure with the District Office may be fined up to $1,000.00 and may be required by the appropriate District Manager to reenter and replug the well.

[**Source:** Amended at 11 Ok Reg 3691, eff 7-11-94; Amended in Rule Making 97000002, eff 7-1-97; Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001); Amended at 33 Ok Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-11-5. Supervision and witnessing [REVOKED]

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Revoked in Rule Making 97000002, eff 7-1-97]

165:10-11-6. Plugging and plugging back procedures

(a) **Scope.** This Section establishes minimum standards for plugging and plugging back wells. The standards apply to:

(1) Wells drilled for the production of oil or gas.

(2) Wells drilled or used for disposal or enhanced recovery injection.

(3) Wells used in subsurface gas storage units.

(4) Monitoring wells in enhanced recovery projects or subsurface gas storage units.

(5) Wells plugged back for:

(A) Oil or gas production.

(B) Disposal or injection.

(C) Conversion to a water well.

(6) "Rat hole" or "mouse holes" used in rotary drilling of wells.

(7) Wells used for geophysical or geological exploration.

(8) Wells used for other service operations.

(b) **Alternate plugging materials and procedures**

(1) The Manager of Field Operations, or other designated Conservation Division staff member, may approve the use of an alternate material other than cement or in combination with cement for wells listed in subsection (a), provided alternate plugging materials shall not be used to plug or plug back wells listed in subsection (a)(2), wells drilled or used for disposal or enhanced recovery injection, subsection (a)(3), wells used in subsurface gas storage units, subsection (a)(5)(B), wells plugged back for disposal or injection, and underground injection wells authorized under the Oklahoma Brine Development Act, 17 O.S. Section 500 *et seq*.

(2) The Director of Oil and Gas Conservation, in consultation with the Conservation Division's Field Operations staff and the public, shall develop specific plugging criteria for any type of alternate plugging material authorized for use instead of cement or in combination with cement. The plugging criteria for approved alternate material shall be available to the public for review and copying at the Conservation Division's offices and on the Commission's Internet website.

(3) A District Manager may approve alternate plugging procedures for the use of alternate plugging materials.

(4) A detailed description of the alternate plugging operation shall be included with the Plugging Report (Form 1003).

(5) The District Manager shall note his approval of the alternate plugging procedure on the well's Plugging Report (Form 1003).

(6) Any alternate plugging material or procedure shall conform to the minimum plugging standards relating to formations or depths set forth in the Sections below. Provided, based upon the type of alternate plugging material being utilized, the District Manager approving the alternate procedure may authorize variances to the plugging standards delineated in this Section otherwise applicable to the use of cement, where such variances are necessary to ensure an effective well plugging.

(c) **Application and cross references:**

(1) Subsection (n) of this Section provides for administrative approval of alternative plugging procedures if downhole problems in a wellbore prevent an operator from complying with the minimum standards established by this Section.

(2) Subsection (o) of this Section applies to plugging of "rat holes" and "mouse holes" used at the surface during rotary drilling.

(3) OAC 165:10-11-8 establishes additional procedures for identification and control of wellbores in which certain logging tools have been abandoned.

(4) OAC 165:10-7-31 establishes the minimum standards for plugging wellbores used in seismic exploration.

(5) Subsections (d) through (p) of this Section establish plugging and plug back standards for all other wellbores subject to this Section.

(d) **Formations to be plugged.**

(1) Except as provided in (2) of this subsection, for cased formations, if the operator plugs or plugs back a well, the operator shall plug any formation or formations in communication with a formation that:

(A) Bears H_2S;

(B) Bears oil or gas;

(C) Bears treatable water;

(D) Was used in the wellbore for injection as part of a saltwater disposal well or enhanced recovery injection well; or

(E) Is open in the wellbore below either the shoe of the casing or the base of the liner to be left in the well after plugging.

(2) Paragraph (1) of this subsection shall not apply to any formation behind the pipe left in the hole, unless a formation endangers a treatable water formation or any oil and gas bearing formation.

(e) **Mud requirements.** Before or after running a plug, the operator shall remove or displace all oil and saltwater in the wellbore, and the operator shall fill the wellbore and/or casing with drilling (plug) mud. The minimum mud weight shall be nine pounds per gallon. The minimum viscosity for the drilling mud shall be 36 (API Full Funnel Method). If the operator removes casing from the wellbore, the operator shall keep the wellbore filled with drilling mud meeting or exceeding the weight and viscosity requirements of this subsection.

(f) **Approved cementing methods.**

(1) **Cement plugs.**

(A) To plug or plug back a well, either the tubing and pump method or the pump and plug method shall be used and a continuous flow of cement shall be pumped for each stage.

(B) Surface pumping and shut in pressures shall be of sufficient pressure to:

(i) Squeeze off perforations in the casing.

(ii) Prevent the plug from floating upward in the wellbore.

(2) **Bridge plugs.** The operator may run by the bailer method cement required in the casing above a bridge plug as provided by (g) of this Section.

(g) **Use of bridge plugs.**

(1) **Permitted use.** Except as provided in (2) of this subsection for top plugs, a bridge plug may be used to permanently plug off a formation if:

(A) The only openings from the formation into the wellbore are perforations in the casing.

(B) The annulus between the casing and the formation is filled with cement from a depth 50 feet below the base of the formation to a depth 50 feet above the top of the formation.

(C) The bridge plug is set above the top of the perforations in the cemented interval described in (B) of this paragraph.

(D) Sufficient cement is placed on top of the bridge plug to fill the casing from the top of the bridge plug to a depth ten feet above the top of the bridge plug.

(2) **Prohibited use for top plug.** A bridge plug may not be used for a top plug described in (j) of this Section.

(h) **Cement plug for uncased hole below the casing or liner.** If any production casing or liner is to be left in the wellbore, then any uncased hole below the casing or liner shall:

(1) Be filled with cement:

(A) **From** a depth which is the lesser of total depth of the well or 50 feet below the lower of shoe of the casing or base of the liner.

(B) **To** a depth of 50 feet above the lower of the casing shoe or the base of the liner; or

(2) Have a cast iron bridge plug set above the top of the liner with cement.

(i) **Intermediate cement plugs.** If a bridge plug and cement are not used, a cement plug shall be run over any other formation required to be plugged off by this Section. To plug off a formation, the wellbore shall be filled with cement from a depth at least 50 feet below the base of the formation to a depth at least 50 feet above the top of the formation.

(j) **Cement top plug.**

(1) **No treatable water exists.** If no treatable water exists, the wellbore shall be filled with cement from a depth of at least 30 feet to a depth of three feet from the surface.

(2) **Treatable water exists.** Except as provided in (p) of this Section for converting a well to a water well, the wellbore shall be filled with cement as follows:

(A) If there is no surface casing or the base of the surface casing is 25 feet or further above the base of the treatable water, the wellbore shall be filled with cement from a depth of at least 50 feet below the base of the treatable water to a depth the lesser of:

(i) Fifty feet above the base of treatable water; or

(ii) Three feet below surface.

(B) If the surface casing is set at or below the base of the treatable water, the production casing shall be cut off a minimum of 50 feet below the base of the surface casing, the production casing must be removed from the wellbore and the wellbore shall be filled with cement from a depth of at least 50 feet below the base of the surface casing to a depth the lesser of:

(i) Fifty feet above the base of the surface casing; or

(ii) Three feet below surface.

(C) If the cement plug prescribed by (2) of this subsection is not sufficient to bring the level of cement to within three feet from the surface, then the wellbore shall be filled with cement from a depth of at least 30 feet to a depth of three feet from the surface.

(k) **Cutting off surface pipe and identification of the abandoned wellbore.**

(1) This subsection applies to a wellbore plugged for abandonment. It does not apply to a wellbore plugged back for conversion to a water well under (p) of this Section.
(2) After setting the top plugs in a well, the operator shall cut off the casing left in the wellbore three feet below surface, and the operator shall cap the casing in the wellbore with a steel plate.
(3) The operator shall inscribe or embed the well number and date of plugging on the steel plate.

(l) **Tagging the top of the plug.** The Field Inspector for the Conservation Division may require the operator to determine the depth of the top of a plug by running a wireline or tubing string.

(m) **Fall back of cement.** If the cement for a plug falls back during setting below the top depth required by this Section, the operator shall run additional cement until the plug meets the minimum requirements of this Section.

(n) **Alternative plugging procedure for down-hole problems.**
(1) In plugging a well, if the operator encounters a downhole problem which prevents the operator from complying with the standards of this Section, the District Manager may prescribe an alternative plugging procedure provided that the alternative plugging procedure prevents the vertical migration in the wellbore of oil, gas, saltwater, H_2S, and other deleterious substances into a formation bearing oil, gas, or treatable water.
(2) The District Manager shall note his approval of the alternative plugging procedure on the well's Plugging Report (Form 1003).

(o) **Plugging of rat holes and mouse holes.** If a rat hole or mouse hole was used at the surface for drilling the well, it shall be plugged within 90 days after drilling operations are complete as follows:
(1) The hole shall be filled with drilling mud from bottom to a depth eight feet below the surface.
(2) The operator shall fill the hole with cement from a depth of eight feet to a depth of three feet below the surface.
(3) The operator shall fill the hole with dirt from a depth of three feet to surface.

(p) **Plug back for conversion to a water well.** The District Manager may permit a well operator to plug back a well for permanent use as a water well by:
(1) Setting any bottom hole and intermediate plugs required by this Section.
(2) Setting a top cement plug from the base of treatable water to 50 feet below the base of treatable water.
(3) Obtaining written permission from the owner of the ground water rights for conversion of the well to a water well.
(4) Submitting under 165:10-11-7, a Plugging Report (Form 1003) noting the conversion of the well with a copy of the written permission from the owner of the ground water rights for conversion of the well to a water well.
(5) A determination must be made by the Oklahoma Water Resources Board as to whether the well is to be permitted as a water well.

[**SOURCE:** Amended at 13 Ok Reg 2395, eff 7-1-96; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000013, eff 7-15-98; Amended in Rule making 980000034, eff 7-1-99; Amended in Rule Making 200200017, eff 7-1-02; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-11-7. Plugging record

(a) Within 30 days after plugging a well, the owner or operator of the well shall submit for the well to the appropriate Conservation Division District Office:
(1) Plugging Record (Form 1003).

(2) Form 1003 shall be completed and signed by employees of both the operator and the cementer.
(3) If a Completion Report (Form 1002A) has not been submitted for the well, Form 1002A shall be attached to the Form 1003.

(b) Any operator failing to comply with this Section may be fined up to $500.00.

[**SOURCE:** Amended at 9 Ok Reg 2295, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 33 OK Reg 593, eff. 8-25-16 (RM 201600001)]

165:10-11-8. Procedures for identification and control of wellbores in which radioactive sources have been abandoned

(a) **Notice and permission to abandon.**
(1) When a radioactive source has been lost and abandoned in a well bore, the operator shall immediately notify the appropriate District Office and request permission to plug or plug-back and/or bypass to conform to the conditions set out in this Section. The District Manager or his designee may exercise the option of witnessing the procedure.
(2) A radioactive source shall not be considered abandoned until all reasonable efforts have been expended to retrieve the source.

(b) **Method of plugging.**
(1) Wells in which radioactive sources have been abandoned shall be mechanically equipped and plugged in such a manner so as to prevent either accidental or intentional mechanical disintegration of the radioactive source.
(2) When a radioactive source has been lost in a well bore and cannot be recovered, the tool shall be covered with a 100 foot plug consisting of standard oil field cement with an approved deflection tool cemented in place at the top of the plug. An additional 100 foot plug colored by red iron oxide shall be run on top of the deflection tool.

(c) **Approval for alternate plugging method.** When an operator, after expending all reasonable efforts, finds that it is not possible to abandon the source as prescribed in (d) of this Section, an alternate plugging procedure must be approved by the Commission prior to use.

(d) **Markers for wells in which a radioactive source has been abandoned.** Upon abandonment of a well in which a radioactive source has been abandoned, and the abandonment procedure has been approved by the Commission, the operator shall cause a permanent plaque to be attached to casing remaining in the well within thirty (30) days of such abandonment. The plaque shall be attached in such a manner that reentry could not be accomplished without disturbing it. The plaque shall be constructed of a long lasting material and shall contain the following information:
(1) Well name and well number.
(2) Name of operator.
(3) The source material abandoned.
(4) Total depth of the well.
(5) The latitude and longitude and the true vertical depth of the location of the abandoned radioactive source in the well bore. For purposes of this Section, true vertical depth is measured at the surface location of the well bore in which the radioactive source has been abandoned.
(6) The date of abandonment.
(7) The activity of the source.
(8) Trefoil radiation symbol with a radioactive warning.

(e) **Completion reports and plugging records of wells with lost radioactive sources.** When a radioactive source has been lost and abandoned in a well bore, both the Form 1002A Completion Report and Form 1003 Plugging Record submitted by the well operator to the Commission pursuant to OAC 165:10-3-25 and OAC 165:10-11-7, respectively, shall contain all of the information required in (d) of this Section. The well operator shall also forward copies of the Form 1002A

Completion Report and Form 1003 Plugging Record to the Radiation Management Section of the Oklahoma Department of Environmental Quality.
(f) **Record of abandoned radioactive sources.** The Commission will maintain a current listing of all wells in which radioactive sources have been abandoned.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007)]

165:10-11-9. Temporary exemption from plugging requirements
(a) **Scope.** The Commission may permit any well which is required to be properly abandoned pursuant to OAC 165:10-11-3 and OAC 165:10-11-5, at the request of an operator, to be temporarily abandoned.
(b) **Application.** An application for a permit to temporarily exempt a well from the plugging requirement shall be made on Form 1003A completed in its entirety, and submitted to the appropriate Conservation Division's District Office.
(c) **Permit.**
(1) Any operator seeking approval for temporary abandonment shall submit a notice of intent to temporarily abandon the well, Form 1003A, to the appropriate District Office describing the temporary abandonment procedure used.
(2) The permit will be valid for a period of five (5) years. At least 30 days prior to the expiration of any approved temporary abandonment permit, the operator shall return the well to beneficial use in accordance with Commission rules, permanently plug and abandon said well, or apply for a new permit to temporarily abandon the well.
(3) No temporary abandonment will be approved that does not prevent the contamination of treatable water and/or other natural resources and the leakage of any substance at the surface.
(4) If the well fails the tests required herein the problem shall be found, corrected and a new test successfully conducted within 30 days or the well shall be plugged and abandoned in accordance with Commission rules.
(5) Upon successful completion of the work on the temporarily abandoned well, the operator will submit a new request for temporary abandonment to the appropriate District Office.
(d) **Protection of treatable water.** The treatable water shall be protected by one or more of the following:
(1) A drillable, retrievable or temporary bridging plug set above the producing interval and below the top of the cement. The surface shall be capped with a valve in operational condition. A pressure test may be required by the appropriate District Office.
(2) A packer run on tubing and set above the producing interval and below the top of the cement. The well shall be equipped with suitable wellhead packoff equipment and be closed to the atmosphere.
(3) A fluid level test determined by use of equipment approved by the Conservation Division's Field Operations Department. The fluid level must be no higher than 150 feet below the base of the treatable water. The Field Inspector shall be notified at least 48 hours beforehand to be afforded the opportunity of witnessing the procedure. Fluid level tests must be conducted annually each of the five (5) years during the anniversary month of the permit. Additional tests may be required at any time at the request of the Conservation Division's Field Operations Department. The wellhead shall be closed to the atmosphere.
(4) A casing inspection log confirming the mechanical integrity of the production casing submitted to the appropriate Conservation Division's District Office.
(5) Alternate methods of testing may be approved by the Conservation Division's Field Operations Department by written application and upon showing that such a test will provide information sufficient to determine that the well does not pose a threat to natural resources.

(e) **Surface facilities.** The well site of a well with temporary exemption from the plugging requirements shall be kept in a neat and orderly manner, including lease roads, with a legible sign showing the name of the operator, operator telephone number, well name, number, and the legal location.

(f) **Termination of permit.** The permit for a temporary exemption from plugging shall terminate and plugging operations shall commence within 30 days after:

(1) The time interval set has lapsed and a renewal has not been granted.

(2) The lease or unit on which the exempted well was located has become nonproductive.

(3) The fluid level has risen to a point less than 150 feet below the base of the treatable water.

(4) The Conservation Division's Field Operations Department has determined that the surface area or wellhead equipment requirement does not meet the standards required by the Commission.

(g) **Exception to termination of permit.** An exception to the termination of an exemption from the plugging requirements shall be allowed if:

(1) An application to convert the well to a disposal, injection, or supply well has been filed with the Commission, and proper notice, according to OAC 165:5, has been met.

(2) An application requesting an exception to the plugging rules has been filed with the Commission and an exception has been granted by an order of the Commission.

[**SOURCE:** Added at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 97000002, eff 7-1-97; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

SUBCHAPTER 12. PROCEDURES FOR THE SEEPING NATURAL GAS PROGRAM

165:10-12-1. Purpose

The purpose of this Subchapter is to provide the Oklahoma Corporation Commission ("Commission") rules to govern responses to occurrences concerning the Seeping Natural Gas Program. All procedural rules necessary to initiate, regulate and administer the Seeping Natural Gas Program are contained in this Subchapter.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007]

165:10-12-2. Coordination of Seeping Natural Gas Program

The Commission shall coordinate response efforts when notified of an occurrence of seeping natural gas. The Commission shall enlist private industry, state, county, municipal, and local government official entities as needed. These entities will aid the Commission with investigating, identifying and abating the hazard. If the Commission has determined that the applicable utility may be responsible for the problem, even though the utility initially advised the Commission it was not, the Commission can require the utility to run further tests to re-evaluate the occurrence as to the utility's lines and equipment. These rules do not supersede OAC 165:45-11-11 (a)(9).

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007]

165:10-12-3. Jurisdiction and scope

Pursuant to 52 O.S. Section 317.1, the Commission is directed to promulgate and enforce rules, and issue and enforce orders relating to seeping natural gas. The rules of this Subchapter shall be known as the Commission Procedures for the Seeping Natural Gas Program, and shall be cited as OAC 165:10-12-1 *et seq*.

(1) The rules of this Subchapter shall govern all proceedings concerning the Seeping Natural Gas Program.

(2) The Commission retains the authority to grant an exception, for good cause shown, to any rule contained herein unless otherwise precluded by law.

(3) The rules of this Subchapter establish procedures for the investigation of seeping natural gas and the administration of the Seeping Natural Gas Fund for the purpose of providing funding to eligible property owners for the mitigation of seeping natural gas on their property, in those cases in which the Commission is unable to abate the hazard of a seeping natural gas occurrence by issuing an order to a responsible person or by plugging a well.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007; Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-12-4. Administration of the fund

(a) The Commission will appoint the Director of Administration of the Commission as the Seeping Natural Gas Fund Administrator.

(b) The Administrator is expressly authorized to bring actions before the Commission to enforce provisions of this Subchapter.

(c) The Administrator shall act under the supervision of the Commission, to administer the Seeping Natural Gas Fund in accordance with the rules and procedures approved by the Commission and consistent with this Subchapter. The Administrator is authorized to enforce, implement, and administer applicable rules and orders of the Commission.

(d) The Administrator's general duties shall include but not be limited to:

(1) Providing disbursements from the Fund;

(2) Managing the daily operations and affairs of the Fund;

(3) Engaging annual audits of the expenditures of the Fund and of the distribution from the Fund to property owners who receive payment from the Fund;

(4) Resolving disputes related to issues addressed in this Subchapter;

(5) Reviewing all applications for assistance from property owners;

(6) Performing any other duties as directed by the Commission.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007]

165:10-12-5. Definitions

The following words or terms, when used in this Chapter, shall have the following meaning unless the context clearly indicates otherwise:

"Hazardous gas concentration" means a concentration that presents or causes a risk of accident or fire.

"Natural gas" means a highly compressible, highly expansible mixture of hydrocarbons having a low specific gravity and occurring naturally in gaseous form. Besides hydrocarbon gases, natural gas may contain appreciable quantities of nitrogen, helium, carbon dioxide, hydrogen sulfide, and water vapor.

"Person" means any individual, business association or corporation, partnership, governmental or political subdivision, public corporation, body politic and corporate public authority, trust or any other legal entity.

"Responsible party" means any person or persons responsible for a facility which is found to be causing a seeping natural gas occurrence.

"Seeping natural gas" means natural gas which has migrated into, under or around a structure at hazardous concentrations.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007]

165:10-12-6. Notice requirements for seeping natural gas occurrences

(a) Upon identification of a possible occurrence of seeping natural gas, a utility shall notify the Pipeline Safety Department of the Commission. If the Pipeline Safety Department determines that the seeping gas occurrence is not caused by a pipeline under its jurisdiction, Pipeline Safety will contact the Public Utility Division and the Oil and Gas Conservation Division.

(b) Upon a utility's initial determination that hazardous gas seepage is not from its system, the utility shall provide the property owner with a brochure explaining the situation and providing the impacted property owner with information about available assistance, including pertinent Commission telephone numbers. For assistance, the property owner or an authorized representative of the property owner shall contact the Commission.

(c) The appropriate District office of the Oil and Gas Conservation Division will contact the local Fire Marshall/Fire Chief and the utility to inform them that the Rapid Action Assessment Team has been activated.

(d) The Field Operations Department of the Oil and Gas Conservation Division will assess and evaluate the situation and act accordingly.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007; Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-12-7. Commission Rapid Action Assessment Team

(a) The Oil and Gas Conservation Division shall form a Rapid Action Assessment Team to handle any seeping natural gas occurrence that occurs within the State after determining that it is not caused by a pipeline regulated by the Pipeline Safety Act or a utility.

(b) The Rapid Action Assessment Team will be equipped with qualified personnel and the proper and necessary equipment to handle investigations of seeping natural gas occurrences.

(c) Each Commission District Office will have access to designated trained personnel and equipment prepared for investigating a seeping natural gas occurrence.

(d) No person entering upon the land to investigate or abate the hazards pursuant to the authority of the Commission will be held responsible for future abatement work on the land or be liable for damages or otherwise for conditions subsequently arising or in connection with the land.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007]

165:10-12-8. Standard procedure for the Rapid Action Assessment Team

As soon as the Oil and Gas Conservation Division is notified of an unknown gas surface seep in or around a structure that the utility has determined is not leaking from its lines, except in situations where the Oklahoma Emergency Management Plan is activated, appropriate Commission personnel will respond as follows:

(1) The Field Inspector from the Oil and Gas Conservation Division will respond with gas detection equipment and notify the Field Supervisor and District Manager.

(2) The District Manager will activate the local Rapid Action Assessment Team and notify local officials and the following Commission offices in Oklahoma City: Public Utility Division, Field Operations and Public Information.

(3) The District Office will research well data, aerial photos and maps on file with the Oil and Gas Conservation Division.

(4) The Oil and Gas Field Supervisor and Field Inspector will coordinate with any responsible party in the locality and will research any available maps and records.

(5) If no known oil or gas wells are present, the Rapid Action Assessment Team will number and set soil gas monitoring probes at strategic locations in the area and initiate a gas monitoring program to measure the concentration and sample the composition of gas and log results at monitored locations.

(6) If the source of gas can be identified and there is a responsible party, the Rapid Action Assessment Team will request a Commission order directing the responsible party to abate the hazard.

(7) If no known responsible party is located, the Rapid Action Assessment Team will position the monitoring system to allow for measurement of concentration and dissipation of the gas.

(8) Upon the completion of the mitigation process, the Commission shall notify the utilities in writing.

(9) Upon notification by the Commission that the mitigation process has been completed, the utility shall verify that the hazard has been abated prior to establishing or resuming gas service.

(10) If the utility believes it should not establish or resume service, it shall file an emergency application with the Commission to show cause why service should not be established or resumed. The Commission shall hear such application with or without notice. At the time of the hearing, the Commission shall receive exhibits and recommendations as required by OAC

165:5-9-3. The Commission shall rule on the request as it deems appropriate.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007; Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-12-9. Assistance to owners of property

(a) An owner of property which has a seeping natural gas occurrence as defined by 165:10-12-5 shall file an application (Form 3000NGS) with the Commission for the investigation and/or abatement of seeping natural gas, to receive assistance with installing a system to divert seeping natural gas away from the structure or to otherwise abate the hazard.

(b) After the Oil and Gas Conservation Division and the Public Utility Division have completed their review of the property owner's application, they will forward it to the Director of Administration of the Commission, and the Director of Administration will consider the application for Commission action.

(c) The Commission shall determine the eligibility of the owner of a structure for assistance based on the nature and extent of the hazard, whether the owner is unable to inhabit the structure, the financial need of the owner of the structure and other relevant factors dependent upon the Oklahoma Legislature's current and future approval of and appropriation for the Natural Gas Seep Program.

(d) If the property owner's application is approved, the Commission may expend funds, pursuant to 17 O.S. Section 180.10, to engage the services of a contractor to install a system to divert natural gas away from a structure or to otherwise abate the hazard.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007; Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-12-10. Reimbursement of expenditures

(a) The Commission may seek reimbursement of expenditures made by the Commission from a responsible party. Any monies received as reimbursement shall be deposited to the credit of the Commission Gas Seep Fund.

(b) The Rule shall not relieve any person or persons otherwise legally responsible from any obligation to properly abate hazards associated with seeping natural gas.

[**SOURCE:** Added at 24 Ok Reg 1806 (RM 200700004), eff 7-1-2007]

SUBCHAPTER 13. DETERMINATION OF ALLOWABLES - OIL AND GAS WELLS

165:10-13-1. Oil and gas production [RESERVED]

165:10-13-2. Classification of wells for allowable purposes

(a) For purposes of this Subchapter the terms gas, oil, and gas-oil ratio are defined in 165:10-1-2.
(b) Any well having a gas-oil ratio of 15,000 to one or more shall be classified as a gas well for allowable purposes.
(c) Any well having a gas-oil ratio of less than 15,000 to one shall be classified as an oil well for allowable purposes.
(d) If a well is a multiply completed well under 165:10-3-35, then each zone of the completion shall be classified separately for allowable purposes.
(e) If a well is commingled under 165:10-3-39, the classification of the well for allowable purposes shall be determined by the gas-oil ratio of the commingled production.

165:10-13-3. Production tests on new, re-entered, and recompleted wells

(a) On all new wells, re-entered wells, and recompleted wells classified as oil wells for allowable purposes, in any regular spacing unit(s) and reservoir dewatering oil spacing unit(s), initial production tests shall be performed and reported to the Commission on Form 1029A for discovery oil wells, Form 1002A for other oil wells, unless otherwise specified by order of the Commission. The test shall not commence until after recovery of a volume of oil equivalent to or greater than the amount of load oil or other liquids introduced into the well.
(b) On all new wells, re-entered wells, and recompleted wells classified as gas wells for allowable purposes, initial production tests shall be performed and reported to the Commission on Form 1016 unless otherwise specified by order of the Commission or by OAC 165:10-17-7(b)(1).
(c) If special pool rules prescribe, by order of the Commission, the manner in which production tests are to be performed in any separate common source of supply, the production or gas-oil ratio test shall be performed and reported to the Commission in accordance with such special pool rules.

[**SOURCE:** Amended at 19 Ok Reg 639, eff 1-14-02 (emergency); Amended at 19 Ok Reg 966, eff 7-1-02 (RM 200100009); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003) ; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-13-4. Reservoir performance tests

The Commission may require, from time to time, the presentation of such data and facts as may be necessary to indicate reservoir performance and conditions in any oil or gas pool. The Commission may witness or supervise the taking of such reservoir performance tests and keep such records as it deems necessary to properly regulate the operation of any oil or gas pool. Any test requested by

the Commission may be witnessed by any operator in the pool. When special pool rules require bottom hole pressure tests, the tests shall be reported to the Conservation Division on Form 1027.

165:10-13-5. Most efficient rate

Subject to the procedural requirements of 165:5-7-12, the Commission may issue an order increasing or decreasing the rate of oil and gas production in an oil pool to correspond to the most efficient rate of production which is consistent with sound engineering and conservation practices as may be justified by the circumstances and evidence submitted.

165:10-13-6. Load oil

Load oil used in well completions which is not produced from the same lease or spacing unit shall not be charged against the well, lease, or unit. The well shall be allowed to produce such load oil in addition to the current monthly allowable. Operators claiming credit for load oil for allowable purposes may file Oklahoma Tax Commission Form 317 not more than 6 months after treating the well.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-13-7. Production from different pools

(a) In the event there are two or more common sources of supply produced through a well or wells on the same lease or drilling and spacing unit and which are not commingled under 165:10-3-39, the production from each common source of supply shall be separately produced, measured, and/or accounted for to the Commission.

(b) If one or more of the zones produced are classified as oil for allowable purposes, the operator of the well shall submit to the Conservation Division a multi-zone report on Form 1011 showing the production from each oil-bearing common source of supply on or before the last day of the succeeding proration period.

165:10-13-8. Transfer of allowables

Subject to the procedural requirement of 165:5-7-12, the Commission may issue an order transferring, after proper adjustment, all or part of an allowable from a well with a high gas-oil ratio or high water-oil ratio to a well having a lower gas-oil ratio or water-oil ratio, if:

(1) The wells produce from the same common source of supply.

(2) The wells are located on the same lease or in the same drilling and spacing unit.

165:10-13-9. Allowable for increased density well

(a) **Allowable production.** Except as otherwise provided by rule or order of the Commission, the allowable production for permitted wells within a drilling and spacing unit producing from the same common source(s) of supply shall be determined as follows:

(1) Each individual well shall be classified for allowable purposes by gas-oil ratio under 165:10-13-2.

(2) Permitted wells of the same classification for allowable purposes shall share a single well allowable.

(3) Permitted wells of different classifications for allowable purposes shall receive allowables as provided by the order of the Commission authorizing the additional well(s).

(b) **Shared single allowable.** If two or more wells in a single drilling and spacing unit are classified as gas wells for allowable purposes, the shared single allowable for the unit shall be determined by the greater of:

(1) A minimum allowable; or

(2) A normal allowable based on the wellhead absolute open flow potential of the best well in the drilling and spacing unit producing from the same common source of supply.

(c) **Additional well.** If an additional well is not of the same classification as any prior permitted well, it shall receive an allowable as provided by the order permitting the well.

(d) **Effect of penalties.** If the allowable for a well in a drilling and spacing unit is subject to a percentage penalty or lid on production, the penalty or lid on production shall apply to the ratable share of production of the shared single allowable for the penalized well as opposed to the entire shared single allowable for the unit.

(1) The ratable share of production of the shared single allowable for an unallocated gas well is that volume of gas which bears the same ratio to the shared single allowable as the wellhead absolute open flow potential for the well bears to the sum of the wellhead absolute open flow potentials for all wells in the drilling and spacing unit of the same classification for allowable purposes.

(2) The ratable share of production of the shared single allowable for a special allocated gas well is that volume of gas which bears the same ratio to the shared single allowable as the unpenalized monthly allowable the well would receive if it were the only well in the unit bears to the sum of such allowables for all the wells in the drilling and spacing unit of the same classification for allowable purposes.

(3) No special allocated well shall receive an allowable less than the defined minimum unit allowable divided by the number of wells in the drilling and spacing unit of the same classification for allowable purposes.

(4) The ratable share of production of the shared single allowable for an oil well is that volume of oil which bears the same ratio to the shared single allowable as the potential for the well bears to the sum of the potentials for all wells in the drilling and spacing unit of the same classification for allowable purposes. If the oil well was assigned a separate allowable under (c) of this Section, the penalty shall apply to the allowable assigned to the well.

(5) The portion of the shared single allowable representing the reduction in the allowable for the penalized well is not allocable to other wells in the drilling and spacing unit.

(e) **Which operator shall file required tests.** If the operators of the wells in a drilling and spacing unit cannot agree as to which operator shall file the required tests and production reports for the unit or as to what proportion of a shared single allowable shall be attributable to each well of the same classification for allowable purposes, the Commission may, after application, notice, and hearing, issue an order determining which operator shall file the tests and reports or what the proportional share of the shared single allowable is attributable to each well or the maximum rate of allowable production for each well.

(f) **Wellhead absolute open flow potential.** For the purpose of this Section, the wellhead absolute open flow potential for a test exempt gas well shall be presumed to equal:

(1) The average daily production for the previous calendar year (or that portion of the previous calendar year if the first sales date was after January 1 of that year), or the minimum allowable that would otherwise be assigned to an unallocated gas well under applicable rules of the Commission as if such well were the only well in the unit, whichever is less, for an unallocated well; or

(2) The product of two multiplied by the monthly allowable for the well under 165:10-17-9 for a special allocated well.

(g) **Testing or reporting requirements.** This Section shall not exempt any well from any testing or reporting requirement imposed by rule or order of the Commission.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99]

165:10-13-10. Applications for reinstatement of cancelled underage for oil wells and for unallocated gas wells

(a) **Oil well.**

(1) With respect to an oil well, all underage for the proration period in excess of 15 percent of the allowable shall be automatically cancelled at the end of the proration period, except underage accrued under (4) of this subsection because of the failure to split a tank.

(2) A producer may apply to reinstate cancelled underage if the well is capable of producing in excess of its allowable. The procedure for applying for reinstatement of cancelled underage is described in (c) of this Section.

(3) Except in situations where the operator has failed to comply with applicable well testing and reporting requirements of the Commission, failure or refusal of the purchaser to take the allowable shall be grounds for reinstatement of any underage accumulated because of such failure or refusal. Underage of this nature may be accumulated until balanced by future runs.

(4) The operator shall not be required to sell less than a full stock tank of oil by the end of the proration period to avoid cancellation of underage. Instead, such underage may be accrued until the operator accumulates and sells a volume of oil from the tank amounting to a full tank, and the sale of oil representing such underage shall not be considered as overage.

(b) **Unallocated gas well.**

(1) With respect to any unallocated gas well, of the total underage for the well or unit existing at the end of the proration period, 75% shall be automatically cancelled and 25% shall be automatically carried forward to the next prorationing period.

(2) Said underage carried forward to the next balancing period must be utilized in said balancing period, with that amount of underage carried forward but not used, to be cancelled at the end of the prorationing period.

(c) **Procedure for reinstatement of cancelled underage.**

(1) The operator of an oil well may apply for reinstatement of cancelled underage by application for administrative approval on Form 1010 within 90 days after cancellation of the underage.

(2) If the Conservation Division declines to approve the Form 1010 application, the applicant shall be notified in writing that application, notice, and hearing under 165:5-7-1 are necessary to obtain reinstatement of cancelled underage.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

SUBCHAPTER 15. OIL WELL PRODUCTION AND ALLOWABLES

165:10-15-1. Classification of oil pools and projects

(a) **Types of oil pools.** Each producing oil pool shall be classified by the Commission into one of the following categories:

(1) Discovery oil pool (165:10-15-5).
(2) Allocated oil pool (165:10-15-9).
(3) Unallocated oil pool (165:10-15-12).
(4) Enhanced oil recovery project (165:10-15-14).
(5) Excessive water exempt oil project (165:10-15-16).
(6) Reservoir dewatering oil spacing unit (165:10-15-18).

(b) **Treatment of an oil well located in a gas pool.** An oil well located in a gas pool shall be treated as an unallocated oil well, unless the oil well is subject to one of the following:

(1) Pool rules controlled by volumetric withdrawal.
(2) Discovery oil pool rules.
(3) Allocated oil pool rules.
(4) Some other order of the Commission.

(c) **Discovery oil pools.**

(1) A new oil pool which has complied with the provision of 165:10-15-5 may be granted discovery allowable production rates, administratively, subject to either:
(A) Spacing requirements.
(B) Order of the Commission.

(2) Each permitted discovery oil well shall be subject to discovery oil pool rules until either:
(A) Expiration of the discovery allowable period.
(B) Reclassification of the well or pool.

(d) **Allocated oil pool.**

(1) The Commission shall classify an oil pool as an allocated oil pool when:
(A) At any market demand hearing the total production from an oil pool or from any well within the pool needs to be regulated; or
(B) For good cause shown, upon application, notice, and hearing.

(2) A gas well located in an allocated oil pool that is reclassified as an oil well for allowable purposes shall be subject to allocated oil pool rules.

(3) Each allocated oil well shall be subject to the allocated oil pool rules until the Commission reclassifies the well or pool.

(e) **Unallocated oil pools.**

(1) Classification of unallocated oil pool:

(A) Any pool or area which does not require specific regulation and control by the Commission to restrict production to the market demand, aid in the prevention of waste, assure the maximum ultimate recovery of oil and gas from the pool, or protect correlative rights shall be classified as an unallocated pool.

(B) The Commission shall determine which discovery and allocated pools will be placed in the unallocated classification at each market demand hearing.

(2) Each unallocated oil well shall be subject to unallocated oil pool rules until the Commission reclassifies the well or pool.

(f) **Enhanced oil recovery projects.**

(1) **Authorized pressure maintenance.** The Commission may, upon application, notice, and hearing, authorize the pressure maintenance of a pool or the production of oil by the injection of fluid, fluids, gas, gases, or other material into a common source of supply or a portion thereof, whether unitized or not, where substantial quantities of additional oil may be recovered which could not be recovered under ordinary primary depletion methods. When so authorized, the project will be classified as an Enhanced Oil Recovery Project with one of the following classifications:

(A) Pressure Maintenance Project

(B) Gas Repressuring Project

(C) Waterflood Project

(D) Other Enhanced Recovery Projects

(2) **Status of a gas well reclassified as an oil well.** If a well classified as a gas well in an enhanced oil recovery project is reclassified as an oil well for allowable purposes, the well shall be subject to the appropriate enhanced oil recovery project rules.

(3) **Termination of enhanced oil recovery status.** Each enhanced oil recovery well shall be subject to enhanced oil recovery project rules until one of the following occurs:

(A) Termination of the enhanced oil recovery project.

(B) The well is reclassified as a gas well for allowable purposes.

(C) The Commission issues an order reclassifying the well or project.

(D) The well is abandoned.

(g) **Excessive water exempt oil projects.**

(1) **Oil production rates.** The Director of Conservation may administratively authorize the production of oil at rates greater than the normal allowable provided the water-oil ratio of the well and/or pool is greater than or equal to 3:1. All applications shall comply with 165:5-7-12.

(2) **Status of a gas well reclassified as an oil well.** If a well classified as a gas well in an excessive water exempt oil project is reclassified as an oil well for allowable purposes, the well shall be subject to excessive water exempt oil project rules.

(3) **Termination of excessive water exempt status.** Each excessive water exempt well shall be subject to excessive water exempt oil project rules until at least one of the following occurs:

(A) The water-oil ratio declines below 3:1.

(B) Termination of the excessive water exempt oil project.

(C) The well is reclassified as a gas well.

(D) The Commission issues an order reclassifying the well or project.

(h) **Allowable for reservoir dewatering oil spacing unit.**

(1) **Oil production rates.** To set an allowable for a well in a reservoir dewatering oil spacing unit, the operator shall refer to Appendix J and submit the appropriate forms and/or application as provided in OAC 165:10-15-18.

(2) **Reclassification of oil well as gas well.** If a well in a reservoir dewatering oil spacing unit is later subject to reclassification as a gas well for allowable purposes, such reclassification will be determined according to general classification procedures based on the its gas/oil ratio pursuant to OAC 165:10-1-6(d) and (e) and 165:10-13-2. If the subject well is designated an excessive water exempt oil project pursuant to OAC 165:10-15-1(g) and 165:10-15-16, reclassification shall be determined by OAC 165:10-15-1(g)(2). If the subject well is assigned an allowable based upon its most efficient rate pursuant to OAC 165:10-13-5, such allowable shall remain in effect under the order establishing the production rate, so that the well will not be reclassified, until its status is modified or terminated by the terms of the instant or a subsequent Commission order.

(3) **Termination of reservoir dewatering oil spacing unit allowable.** The oil allowable assigned a reservoir dewatering oil spacing unit shall remain in effect until one of the following occurs:

(A) The subject well is reclassified as a gas well pursuant to OAC 165:10-1-6 and 165:10-13-2.

(B) The subject well's status as an excessive water exempt oil project is terminated pursuant to OAC 165:10-15-1(g)(3).

(C) The subject well's status under a most efficient rate order is modified or terminated by the terms of the instant or a subsequent Commission order.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

165:10-15-2. Overage adjustments for oil wells

No well, lease, unit, or project shall be overproduced in excess of 15 percent of the allowable for the proration period. All overage accrued at the end of the proration period shall be deducted from the allowable for the second succeeding proration period.

165:10-15-3. Effect of percentage penalty on oil wells

If a percentage penalty has been assigned to an oil well, the penalty shall, depending on the status of the well, be subtracted from:

(1) **Discovery status.** The applicable allowable from the Discovery Allowable Table (Appendix B to this Chapter) or the capacity of the well to produce as reported, whichever is less.

(2) **If allocated or unallocated per-well status.** The applicable allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor or the capacity of the well to produce as reported, whichever is less.

(3) **If unallocated per-lease status.** The shallowest ten acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor for the penalized well only. The penalty shall be subtracted from the lease allowable.

[**SOURCE:** Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-15-4. Discovery oil pools [RESERVED]

165:10-15-5. Discovery oil allowables

(a) **Number of barrels of oil per day and duration of the discovery allowable period.** The maximum number of barrels of oil per day and the duration of the discovery allowable period shall be determined from the Discovery Allowable Table (Appendix B to this Chapter) or the Allocated Well Allowable (Appendix A to this Chapter), whichever is greater, provided that the well is in compliance with the other provisions of this Section and other rules pertaining to allowables. If the well is not capable of producing at the discovery rate without causing preventable waste, the temporary discovery allowable shall be

the capacity of the well to produce as reported, unless otherwise limited by the Commission.

(b) **Effective date of discovery allowable.**

(1) The discovery allowable period for the pool shall begin with the date of first completion of the discovery well of the pool and extend as provided in the Discovery Well Allowable Table (Appendix B to this Chapter).

(2) The discovery allowable period for each well in the pool shall run from the date specified under 165:10-15-7 for each well to the date of termination of the pool, if granted administratively.

(3) If application, notice, and hearing are required, the effective date of the discovery allowable period shall be specified by an order of the Commission, provided that such date shall not precede the date of filing of the application. The date of expiration of the discovery allowable shall still be determined as set forth in (1) of this subsection.

(c) **Gross allowable production.** The gross allowable production for any proration period from a well in a discovery pool may, at the option of the operator, be produced at any time during the proration period; however, in no event shall the production exceed the maximum efficient rate of flow.

[**SOURCE:** Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-15-6. Production tests and reports for discovery oil pools

(a) **Initial test requirements.** The operator of each well in each discovery pool shall perform an initial potential test and furnish the Conservation Division the results of such test not later than 30 days after completion of each well. Each individual well shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(b) **Witnessing of tests.**

(1) With respect to initial test, the operator shall give twenty-four (24) hour notice of the opportunity to witness said test to the Conservation Division and the offset operator(s) producing from the same pool, but no waiver or signature of Conservation Division personnel is required.

(2) Any operator in the pool may witness any official test for any well in the pool. However, any person other than a Commission employee witnesses a test at their sole risk and expense.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-15-7. Procedure for obtaining discovery allowable

(a) Any operator desiring a discovery allowable shall file Form 1028 with the material and information specified below:

(1) A resistivity and a porosity type wireline survey of the well in question, if run.

(2) A Completion Report (Form 1002A) and Cementing Report (Form 1002C), completed in detail.

(3) A Potential Test (Form 1029A), completed in detail.

(4) A plat of the area showing all of the following information for each well within one and one-half (1 1/2) miles of the subject well:

(A) Operator.

(B) Well name and number.

(C) Total depth.

(D) Current status of the well (dry, oil, gas, injection, disposal, temporarily abandoned).

(E) Name of interval open, if any.

(F) Perforations, top and bottom, if any.

(G) Average daily production.

(5) An isopach contour map of the productive interval and/or a structural contour map of a nearby marker bed or formation, not separated from the

producing interval by an unconformity, which is commonly used in the area. The Conservation Division may require either or both types of maps to determine the discovery status. The Commission may also require additional geological and/or engineering data, such as: stratigraphic cross-sections, structural cross-sections, production, and pressure information.

(b) The Conservation Division may administratively designate a discovery allowable for a well when the operator furnishes the Technical Department with the information specified in (a) of this Section. If the information is provided within 30 days of the date of first production and the application is approved, the effective date of the discovery allowable shall be the date of first production. If the information is provided more than 30 days after the date of first production and the application is approved, the discovery allowable shall be effective the date of filing.

(c) If a gas well in a discovery oil pool is reclassified as an oil well for allowable purposes, the operator must file the appropriate form, information and material specified in (a) of this Section within 30 days of reclassifying the well to obtain a discovery allowable. The allowable shall be effective the date the well was reclassified as an oil well as indicated on Form 1002A. If the application is not received within the specified time period, the application will be processed in accordance with (b) of this Section.

165:10-15-8. Allocated oil pools [RESERVED]

165:10-15-9. Allocated oil allowables

(a) **Effective date of allowables.** The allowable for an allocated well completed or recompleted on or after the first day of the proration period shall become effective the date of completion of the well, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.

(b) **Allowables in allocated pools.** Allowables in allocated pools shall be granted on an individual well basis, subject to appropriate spacing requirements, unless otherwise specified by order of the Commission. The allowable for each allocated well shall be determined as if the well was an unallocated well operating under 165:10-15-12(b) or 165:10-15-12(c)(1), whichever is appropriate, unless adjusted by order of the Commission. The operator shall produce the allowable on each well from that well and no part thereof from any other well.

(c) **Application.** Upon application by the Director of Conservation or any interested party, and after notice and hearing, the Commission may order the wells in a common source of supply to be produced under allowables established by special pool rules in lieu of the provisions of this Section. All requirements as to production tests and allowables shall be set forth by the order of the Commission establishing such special pool rules.

165:10-15-10. Production tests and reports for allocated oil wells

All production tests and reports shall be filed as if the allocated well were an unallocated well operating on a per-well basis allowable under 165:10-15-13(a).

165:10-15-11. Unallocated oil pools [RESERVED]

165:10-15-12. Unallocated oil allowables

(a) **Effective date of allowable.** The allowable for a well completed or recompleted on or after the first day of a proration period shall become effective the date of completion of the well, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become

effective the date the operator complies with this Section and other rules governing allowables.

(b) **Well in an unallocated pool.** Each well in an unallocated pool in which drilling and spacing units have been established shall be assigned the applicable allowable on a per-well basis from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor unless adjusted by order of the Commission. The production from each well shall be separately accounted for to the Commission.

(c) **Lease in an unallocated pool.** Each individual lease in an unallocated pool in which drilling and spacing units have not been established shall be assigned allowables, at the option of the operator, on either of the following basis:

(1) **A per-well basis.** If the operator elects to accept the per-well basis allowable, each well on the lease shall be assigned an allowable applicable to a ten-acre or less allowable at the appropriate depth from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor unless adjusted by order of the Commission. The production from each well shall be separately accounted for to the Commission.

(2) **A per-lease basis.** If the operator elects to accept the per-lease basis allowable, the allowable for the lease shall be the shallowest ten-acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor multiplied by the number of wells on the lease unless adjusted by order of the Commission. The production from each lease shall be separately measured and accounted for to the Commission.

165:10-15-13. Production tests and reports for unallocated oil wells

(a) **Per-well basis allowable.**

(1) If the well is an allocated well, or an unallocated well located on lands in which drilling and spacing units have not been established and the operator elected to accept allowables on a per-well basis, or an unallocated well located on lands in which drilling and spacing units have been established, the operator shall file a production test no later than 30 days after the earlier of:

(A) Making the election,

(B) Completion of the well, or

(C) Recompletion of the well.

Each individual well shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(2) Each new well shall be given an allowable equal to the allowable for an unallocated per-well basis well until the production test has been performed with the results reported to the Conservation Division. The allowable shall be effective for a period not longer than 30 days from completion of the well. A Form 1002A Completion Report may be used in lieu of a Form 1029A to establish an oil allowable if oil and gas production rates reported on Form 1002A establish the well's classification as an oil well. No further allowable shall be assigned to the well until compliance with this subsection.

(3 Until an operator submits the required test results for any well, as provided in subsection (a)(1), no allowable shall be assigned to the well. If said test results are filed late, then the allowable shall be effective the first day of the following month after the Conservation Division accepts the test.

(4) All initial tests shall be conducted in the manner set forth in (1) of this subsection.

(5) Annual testing shall not be required.

(b) **Per-lease basis allowables.**

(1) If the well is an unallocated well located on lands in which drilling and spacing units have not been established and the operator elects to accept

allowables on a per-lease basis, the operator shall file a production test with the Conservation Division not later than 30 days after:

(A) Making the election,
(B) Completion of the initial well on the lease,
(C) Completion of a subsequent well on the lease,
(D) Recompletion of any well on the lease, or
(E) Retesting of any well on the lease.

Each well on the lease shall be tested for not less than six hours and not more than 24 hours with the production calculated and reported at a daily rate (24 hours).

(2) Each lease shall be given an additional allowable equivalent to the shallowest ten-acre or less allowable from the Allocated Well Allowable Table (Appendix A to this Chapter) multiplied by the current market demand factor for each new producing well added to the lease until the production test has been performed with the results reported to the Conservation Division. The additional allowable shall be effective for a period not longer than 30 days from completion of the well. No further additional allowable shall be assigned to the lease until compliance with this subsection.

(3) If an operator fails to submit the required test results for any lease with allowables calculated on a per-lease basis, no allowable shall be assigned to the lease. The operator may submit the results of the test to the Conservation Division to reinstate the allowable. A Form 1002A Completion Report may be used in lieu of a Form 1029A to establish an oil allowable if oil and gas production rates reported on Form 1002A establish the well's classification as an oil well. The allowable shall be effective the first day of the following month after the Conservation Division accepts the test.

(4) No lease shall be granted underage resulting from failure to perform a required test in compliance with this Section.

(5) All initial tests, annual tests and retests shall be conducted in the manner set forth in (1) of this subsection.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92; Amended in Rule Making 980000033, eff 7-1-99; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001)]

165:10-15-14. Enhanced oil recovery project allowables

(a) **Effective date of allowable.** The allowable for an enhanced oil recovery project shall be effective on the date operations commenced or the date specified by order of the Commission authorizing the project, whichever is later, provided the operator has complied with the provisions of this Section and other rules governing allowables. In situations where the operator fails to comply, the allowable shall become effective the date the operator complies with this Section and other rules governing allowables.

(b) **Qualification for enhanced oil recovery allowable.** For any project to qualify for an enhanced oil recovery allowable, an order of the Commission authorizing the project must be obtained.

(c) **Allowable for enhanced oil recovery project.** The allowable for an enhanced oil recovery project shall be on a project basis and shall be the capacity of the project to produce.

(d) **Wells on a project producing from another reservoir.** Oil wells within the boundaries of a project which do not produce from the project shall not be permitted to produce any portion of the allowable of such enhanced oil recovery project. The oil produced by non-project wells shall be separately produced, measured, and reported.

165:10-15-15. Production tests and reports for enhanced oil recovery projects

(a) Within 30 days of commencement of any enhanced oil recovery project, the operator shall file with the Conservation Division an inventory of all the wells located within the boundaries of the project completed in the approved common

source of supply showing the name of the project and the new OTC Production Unit Number (including merge number) and the following for each well:

(1) Previous OTC Production Unit Number.
(2) API Number.
(3) Well Name and Number.
(4) Legal location, including quarter quarter quarter quarter section.
(5) Current status (producer, injector, observation, or temporarily abandoned).

The inventory shall also include the current daily (24 hour) production and injection rates for the project.

(b) The operator shall notify the Conservation Division in writing within 30 days of the completion of any new well or the change in status of any existing well in the project.

(c) Until the operator submits the required test results for any enhanced oil recovery project as provided in subsection (a), no allowable shall be assigned to the project. If said test results are filed late, then the allowable shall be effective the first day of the following month after the Conservation Division accepts the tests.

(d) All initial tests shall be conducted as set forth in subsection (a).

(e) Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-15-16. Excessive water exempt oil project allowables

(a) **Effective date of allowables.** The allowable for an excessive water exempt oil project shall be on a well or a project basis and shall be effective when the Conservation Division receives and accepts the production test of, Form 1013, unless otherwise specified by order of the Commission.

(b) **Qualification for excessive water exempt oil project.** For any project or well to qualify for excessive water exempt allowable, an order of the Commission authorizing the well or project must be obtained.

(c) **Allowable for excessive water exempt oil project.** The allowable for a well or project which has received a special excessive water exempt allowable shall be the capacity of the well or project to produce without causing preventable waste unless otherwise adjusted by the Director of Conservation. The production from a well which has received a special excessive water exempt allowable under this Section shall be separately produced, measured, and accounted for to the Commission from the oil produced from the remainder of the lease.

165:10-15-17. Production tests and reports for excessive water exempt oil projects

(a) The operator of each individual well with an excessive water exempt allowable shall file an initial production test on Form 1013 with the Conservation Division. Each individual well shall be tested for seven consecutive days, and the amount of oil and the amount of water produced each day shall be reported on Form 1013. With respect to the initial test, the operator shall give twenty-four (24) hour notice of the opportunity to witness said test to the Conservation Division and the offset operator(s) producing from the same formation, but no waiver or signature of Conservation Division personnel is required on Form 1013.

(b) Each individual well shall be given an initial allowable equal to the unallocated per-well basis allowable until the production test has been performed with the results reported to the Conservation Division on Form 1013. The allowable shall be effective for a period not longer than 30 days from completion of the well. No further allowable shall be assigned to the well until compliance with this subsection.

(c) Until the operator submits the required test results for any excessive water exempt well or project, as provided in subsection (a), no allowable shall be assigned to the well or project. If said test results are filed late, the

allowable shall be effective the first day of the following month after the Conservation Division accepts the test.
(d) All initial tests shall be conducted as set forth in (a) of this Subsection.
(e) Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99; Amended at 33 Ok Reg 593, eff 8-25-16 (RM 201600001)]

165:10-15-18. Production tests and reports for reservoir dewatering oil spacing units
(a) **Effective date for oil allowable.** To establish the commencement date of an allowable for an oil well in a reservoir dewatering oil spacing unit, the operator shall file Forms 1002A and 1013, in lieu of the Form 1029A, with the Commission according to OAC 165:10-13-3 within thirty (30) days after the completion date of the well. The allowable will commence on the date of first production.
(b) **Qualification for reservoir dewatering unit.** Proof of fifty percent (50%) water saturation presented at the time of a hearing to establish dewatering oil spacing may entail calculations from logs or core data from wells within the common source of supply covered by the application or an analogous common source of supply, or an actual production test from a well in the common source of supply covered by the application. To qualify for the reservoir dewatering spacing unit allowable provided on Appendix J, the Form 1013 must provide data that verifies that the water-oil ratio is greater than 1:1. If the water-oil ratio is less than 1:1, then the oil allowable shall be the appropriate allowable for the depth of the top of the formation and the maximum acreage provided in Appendix A.
(c) **Allowable rate not provided for in Appendix J.** To establish an allowable other than that specified in Appendix J, the operator shall file a Form 1030 with the Commission to adjust the allowable.
(d) **Record of annual production rates.** The operator shall maintain production records on an annual basis. Operators shall make these records available to the Conservation Division staff upon the request of the Manager of the Technical Department. Annual testing shall not be required except as provided in OAC 165:10-1-6.

[**SOURCE:** Amended in Rule Making 200100009, eff 7-1-02]

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SUBCHAPTER 17. GAS WELL OPERATIONS AND PERMITTED PRODUCTION

165:10-17-1. Gas production from gas pools [RESERVED]

165:10-17-2. Classification of gas pools

(a) **Types of gas pools.** Each gas pool shall be classified by the Commission into one of the following categories:

(1) Allocated Gas Pool.
(2) Special Allocated Gas Pool.
(3) Unallocated Gas Pool.

(b) **Treatment of gas well in an oil pool.** If a well in an oil pool is classified as a gas well for allowable purposes, the well shall be treated as if it were in an unallocated gas pool, unless the well is subject to pool rules which establish allowables by volumetric withdrawal.

(c) **Allocated gas wells.**

(1) **Classification of pool by order.** Upon application, notice, and hearing, the Commission may issue an order establishing allowables for gas wells in a pool by the allocated gas pool rules in 165:10-17-8.

(2) **Status of an oil well reclassified as a gas well.** If a well classified as an oil well in an allocated gas pool is reclassified as a gas well for allowable purposes, the well shall be subject to allocated gas pool rules.

(3) **Termination of allocated status.** Each allocated gas well shall be subject to allocated gas pool rules until:

(A) The Commission establishes special allocated gas pool rules for the common source of supply.
(B) The well is reclassified as an oil well for allowable purposes.
(C) The Commission issues an order reclassifying the well as an unallocated gas well.
(D) The well becomes the only gas well in the pool.
(E) The well is abandoned.

(d) **Special allocated gas pools.** Each gas pool for which special pool allocation rules (field rules) are or have been established by the Commission shall be classified as a special allocated gas pool. Each gas well in a special allocated gas pool shall be referred to as a special allocated gas well for allowable purposes.

(e) **Unallocated gas pools.** Each gas pool not classified as an allocated gas pool or as a special allocated gas pool shall be classified as an unallocated

gas pool. Each gas well in an unallocated gas pool shall be referred to as an unallocated gas well for allowable purposes.

165:10-17-3. Effective date of allowables

A gas well shall be assigned an allowable as of the date it is connected into a pipeline and the first delivery is made if the Notice of Intention to Drill (Form 1000) is valid, the Completion Report (Form 1002A) is filed with attachments, if required, and all required tests are run within 30 days from the date of first sales and are filed within 45 days of the date of first sales, and special reports have been filed with the Conservation Division.

[**SOURCE:** Amended in Rule Making 980000033, eff 7-1-99]

165:10-17-4. Standard gas measurement law

Sections 471 through 477, inclusive, of Title 52, Oklahoma Statutes Annotated, cited as the "Standard Gas Measurement Law", are hereby adopted as rules of the Commission as fully as if set out verbatim herein.

165:10-17-5. Meters and recorders

(a) **Requirement of a gas meter and recorder.**

(1) For allowable, allocation or custody transfer purposes, each well producing natural gas other than a shut-in gas well shall have a gas meter and recorder for the gathering line; provided, if two or more wells share a single allowable, a single meter and recorder may be used to measure gas production, unless a special order of the Commission or either 165:10-13-9 or 165:10-3-39 require allocation of gas production on a per well basis.

(2) For purposes of (1) of this subsection, the term "recorder" refers to a circular gas chart recorder or other type of recording device which has been mutually agreed upon by the gas seller and the gas purchaser.

(3) For purposes of (1) of this subsection, an offsite recorder shall be permitted provided:

(A) There is compliance with the requirements of (2) of this subsection.

(B) The recording device is made available for inspection by the Conservation Division to determine that the recorder is functioning properly.

(4) Offsite recordation under (1) and (3) of this subsection shall be treated as wellsite metering for purposes of the reporting requirements of 165:10-1-47.

(5) Use of electronic gas measurement and recording devices that meet industry standards of (b)(2) of this Section are permitted for allowable, allocation, custody transfer, and well testing.

(b) **Standards for meters and recorders.**

(1) Each meter and recorder shall be properly constructed, maintained, repaired, and operated to continually and accurately register the quantity of gas produced from the well into a gathering line.

(2) The meter and recorder shall be installed, used, and operated according to the natural gas industry standards and guidelines promulgated by the American Gas Association, the American Petroleum Institute, and the Gas Processors Association, in effect at the time of installation of the meter and recorder. If there are conflicting standards, then the most current American Petroleum Institute standard shall apply.

(c) **Prohibited meter bypasses.** For each meter measuring production at the wellsite, use of piping to bypass the meter is prohibited. Gas meters with internal bypasses are permitted.

(d) **Reporting of estimated volume if the meter or recorder fails.**

(1) **Seventy-two hours to repair equipment.** If a meter or recorder at the wellsite malfunctions, then the malfunctioning equipment shall be repaired within 72 hours after discovery of the malfunction.

(2) **Reporting of estimated volumes while the meter or recorder is down.** If the well continues to produce gas while the meter or recorder is malfunctioning or being repaired, estimated gas volumes shall be reported to the Conservation Division for purposes of 165:10-1-47.

[**Source:** Amended at 12 Ok Reg 2017, 7-1-95]

165:10-17-6. General well testing requirements

(a) All single-point and multi-point potential tests shall be calculated for all non-exempt gas wells in a uniform manner with respect to the following:

(1) The potential shall be the calculated wellhead absolute open flow potential of the well determined by obtaining a static column wellhead flowing pressure and shall indicate the capacity of the well to produce against zero psia at the wellhead.

(2) All pressures used in test calculations shall be corrected to pounds per square inch absolute, using 14.4 psia as the average barometric pressure.

(3) The static column wellhead pressure, either measured or calculated as reported in the potential test, shall be no more than 90 percent of the wellhead shut-in pressure. If data cannot be obtained in accordance with the foregoing provisions, an assumed static column wellhead pressure of 90 percent of the wellhead shut-in pressure shall be used to calculate the results of the test. This paragraph supersedes any contrary provision in special pool rules.

(b) The operator of a well shall be responsible for testing the well and submitting the test results to the Conservation Division. The results of a potential test shall be filed with the Conservation Division on Form 1016. If the operator wishes to obtain a copy of the approved Form 1016, he shall enclose with the original form a self-addressed stamped envelope and one additional copy of the test and/or form. The Conservation Division shall acknowledge such requests within 15 days, stating either the date of acceptance of the test results or rerunning the original test if it has been rejected. If any order or rule of the Conservation Division requires witnessing of a test, the operator of the well shall be responsible for securing the presence of an authorized Conservation Division representative to witness the test and sign the Form 1016 for the test.

(c) Unless otherwise prescribed by special pool rules, field testing procedure shall be performed in accordance with the procedures set out in Oklahoma Corporation Commission Manual of Back-Pressure Testing of Gas Wells, Parts I and II, utilizing the specified tables in the Interstate Oil and Gas Compact Commission Manual of Back-Pressure Testing. A gas turbine meter may be used in lieu of an orifice meter for flow measurements in gas well testing.

(d) The initial test for all gas wells shall be run into the pipeline within 30 days and test results filed within 45 days after the date of first sales of gas. Any test filed after the 45 day limit will not be made effective until the first of the month following the date of acceptance of the test. With regard to initial tests for special allocated gas wells, the operator of the well shall provide twenty-four (24) hours notice to the Conservation Division of its intent to run an initial test in order to give the Conservation Division the opportunity to witness said test, but in no case shall the operator be precluded from performing said test and filing the results as provided for in subsection (b). Initial tests for special allocated gas wells need not be witnessed, nor signatures obtained, if witnessed, in order for the Conservation Division to assign an allowable to said well. Initial tests for unallocated gas wells with calculated open flow of less than two million cubic feet per day are exempt from witnessing by Conservation Division personnel under 165:10-17-7(b)(1).

(e) The annual test for all non-exempt gas wells shall be run into a pipeline in accordance with this Section or applicable pool rules. Any annual test for

a well in a special allocated pool, filed late shall not be made effective until the first of the month following the date of acceptance of the test.
(g) Wells in allocated pools shall be tested in accordance with the requirements for wells in unallocated pools, unless superseded by specific field rules. Form 1016 shall be used to report shut-in pressure tests on wells in allocated and special allocated pools, except for the Guymon-Hugoton Pool #182 which shall use a form 1017 Deliverability Gas Test.

[**SOURCE:** Amended at 16 Ok Reg 2206, eff 7-1-99 (RM 980000033); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003)]

165:10-17-7. Well tests

(a) **Wells in special allocated pools.**

(1) An initial test shall be filed for each newly completed gas well in each special allocated pool. The well shall be tested into a pipeline no later than 30 days after the date of the first sale of gas. Test procedures shall be those specified in the applicable pool rules subject to the uniform requirements of 165:10-17-6.

(2) An annual test shall be filed in accordance with the requirements of the applicable pool rules, subject to the following provisions specific to the Guymon-Hugoton special allocated pool.

(3) W**ells in the Guymon-Hugoton special allocated pool.**

(A) The Conservation Division staff will not be required to witness any well test on any well in the Guymon-Hugoton special allocated gas pool unless requested to do so by an offset operator. Operators have a right to witness any well test on any well offsetting said operator's well in the pool. Operators of offsetting wells will be given sufficient prior notice of testing to allow for a representative to be present to witness testing, and will be provided access to the designated witness throughout testing.

(B) Wells in the Guymon-Hugoton special allocated gas pool which are not capable of producing 450 Mcf/day will be exempt from biannual deliverability tests. Operators shall have the right to elect to receive the minimum allowable by deciding not to conduct well deliverability tests on any such wells in the pool. No well shall be exempt from the annual wellhead shut-in pressure test requirements. For the purpose of the annual wellhead shut-in pressure test, the shut-in pressure shall be measured after the well has been shut-in for approximately 48 hours. In no case shall the well have been shut-in for less than 44 hours at the time the shut-in pressure is taken.

(b) **Wells in unallocated pools.**

(1) **Testing of newly completed or newly recompleted wells.**

(A) An initial test shall be submitted to the Conservation Division for each newly completed gas well or recompleted gas well involving a new formation in an unallocated gas pool under 165:10-17-2. The well shall be tested into a pipeline no later than 30 days after the date of first sale of gas into a pipeline. The flow period for the initial test shall be 24 hours.

(B) It shall not be necessary for the operator to submit the initial flow potential test for an unallocated well with a maximum flow rate of less than the minimum allowable. Only a current 24-hour wellhead shut-in pressure is required, unless otherwise requested by the Commission. A copy of the Form 1002A Completion Report may be submitted in lieu of Form 1016 to establish the minimum allowable, provided the section on the Form 1002A Completion Report requesting a minimum gas allowable is explicitly marked, and the following items are reported:

(i) current 24 hour shut-in pressure;

(ii) date of first sales and date of recompletion, if applicable;

(iii) Oklahoma Tax Commission production unit number; and

(iv) name of reporting entity of monthly gas volumes for the well (either the purchaser/measurer, or self-reporting operator). If the required information is not provided on the Form 1002A Completion Report submitted to the Commission, an initial test on Form 1016 containing the information must be filed with the Commission to establish an initial allowable for the well.

(C) An initial potential test is required to receive an allowable greater than a minimum allowable. If said initial test is taken between January 1 and April 30 of the calendar year, the test shall be used for allowable purposes for the remainder of that calendar year. If the initial test is taken between May 1 and December 31, the test shall be effective for the remainder of the current calendar year, and for the entire succeeding calendar year. A request to extend the time to test may be granted by the Conservation Division in order to recover fluids introduced into the well. The request shall be submitted in writing to the Conservation Division with the expected test date.

(2) **Annual testing or retesting of established gas wells.** A potential test to assign a new allowable for an initially tested well may be submitted on Form 1016 at any time after three months from the date of the initial test. A test run between January 1 and April 30 shall be effective for the remainder of that calendar year. A test run between May 1 and December 31 shall be effective for the remainder of the current calendar year, and for the entire succeeding calendar year. The Director of the Conservation Division may require additional tests at any time. Tests become effective the first day of the month following acceptance of the test by the Conservation Division.

(A) Unless specifically requested by the Director of the Conservation Division, it shall not be necessary to run an annual potential test or retest for an established well having a flow rate of less than the minimum allowable.

(B) Upon expiration of a potential test, the well will revert to a minimum allowable status, unless superseded by a later potential test.

(C) If two or more potential tests are submitted for a well, and the effective periods of the tests overlap or conflict, the test having the greatest calculated open flow potential shall be utilized to determine the well's allowable for the overlapping period.

(3) **One-point tests.** The potential test required for each gas well in each unallocated pool shall use the one-point back pressure method and an assumed flow characteristic of 0.85 shall be used in establishing the wellhead absolute open flow. The test shall be governed by the requirements of OAC 165:10-17-6.

(4) **Durability of minimum allowable.** Once an initial allowable is established for a well, that well shall be assigned at least a minimum allowable until such time the well is plugged, reclassified, recompleted or commingled into an additional formation, or is found to be in violation of a rule or order of the Commission. If a potential test is submitted for the well, that test will supersede the minimum allowable for the effective period of the test set out herein.

(5) **Test exemptions for certain minimum wells.**

(A) The following types of gas wells shall be exempt from initial and annual potential and shut-in tests:

(i) Minimum gas wells producing exclusively from coal bed methane formations.

(ii) Minimum gas wells producing from shale formations or including shale formations, if commingled.

(iii) Minimum gas wells using down hole pumps for artificial lift of produced liquids.

(B) For these exempt wells operators shall report the initial stabilized rate of production on Form 1002A "Completion Report" in lieu of reporting an initial test on Form 1016 "Backpressure test for Natural Gas Wells".

(6) **Minimum compliance.** Each operator shall be responsible for conducting and submitting the required potential tests on the applicable form. All submitted tests must contain complete and accurate information. Permitted production rates will be granted only to those wells which meet this requirement and all other rules or orders of the Commission.

[**SOURCE:** Amended at 14 Ok Reg 2198, eff 7-1-97 (RM 97000002); Amended at Ok Reg 2165, eff 7-1-98 (RM 97000011); Amended at Ok Reg 2206, eff 7-1-99 (RM 980000033); Added at 24 Ok Reg 183, eff 10-4-06 (emergency RM 200600013); Amended at 24 Ok Reg 1784, eff 7-1-2007 (RM 200700004); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001)]

165:10-17-8. Allocated pools

(a) The current monthly allowable for each allocated pool shall be equal to the total production from the pool during the current month.

(b) The current allowable for each capable drilling and spacing unit within the pool shall be that proportion of the pool allowable that the acreage of the drilling and spacing unit bears to the total developed acreage in the pool, adjusted in accordance with any order of the Commission imposing an allowable adjustment. The current allowable for each limited drilling and spacing unit shall be equal to the current production from the unit. A unit shall be deemed limited when its underage is cancelled under this Section until it thereafter produces a current allowable for any one month.

(c) Accrued underage shall be carried forward as a cumulative credit by adding it to the unit's current allowable until the underage has been produced. If the unit's cumulative underage exceeds six times the allowable assigned to it for the preceding January, all of the underage will be cancelled, the unit shall be classified as "limited", and the unit shall not thereafter accumulate underage until such time as the unit produces a current allowable for any one month. All cancelled underage shall be distributed to the capable drilling and spacing units within the pool in the proportion that the acreage of each unit bears to the total capable acreage in the pool, adjusted in accordance with any order of the Commission imposing an allowable adjustment. A capable unit shall be any nonlimited unit. Cancelled underage may be reinstated administratively by the Director of Conservation to any capable unit in an overproduced status within six months after cancellation by application on Form 1010.

(d) Accrued overage shall be carried forward as a cumulative charge against the unit by subtracting it from the unit's current allowable until the overage has been made up. If the cumulative overage exceeds six times the current allowable assigned for the preceding January, the Director of Conservation shall notify the operator in writing, and the unit shall thereafter be permitted to produce not more than 25 percent of its current allowable until all of the overage in excess of six times the well's current allowable for the preceding January has been made up. In the event the operator fails to limit production as herein provided, the well shall be ordered shut-in by the Commission upon application of the Director of Conservation and after notice and hearing.

(e) If a unit did not have a current allowable assigned to it on a full month's basis for the preceding January, the first current allowable assigned to the unit on a full month's basis shall be used as reference for the purpose of limiting underage and overage.

165:10-17-9. Special allocated gas pools

(a) **Scope.** This Section applies to special allocated gas pools except any special allocated gas pool with allowables based upon volumetric withdrawals.

(b) **Minimum unit allowable of 150 mcf/d.** For all special allocated gas pools except the West Cheyenne Upper Morrow, Purvis Chert, Guymon-Hugoton, Custer City N. Hunton, Sharon W. Morrow, Red Oak Fanshawe, Red Oak Red Oak, and Red

Oak Spiro, the minimum allowable for a drilling and spacing unit in the pool shall be 150 MCF/D regardless of the amount of any location exception penalty charged against a unit well. For purposes of this Section, the net minimum allowable shall be the gross minimum allowable adjusted for overage or underage according to this Section.

(c) **Minimum unit allowable of 450 mcf/d for the Guymon-Hugoton pool.**

(1) For the Guymon-Hugoton Special Allocated Gas Pool, minimum allowables shall be determined as follows: The minimum allowable shall be the lesser of 450 mcf/d or the drilling and spacing unit's capability. Capability shall be defined as the average of the highest three (3) of the last twelve (12) months of production. A drilling and spacing unit receiving a minimum allowable shall not accrue underage. The minimum allowables under this Section shall not affect the calculation of capable well allowables. The field monthly allowable shall be equal to total nominations and not adjusted for underage or overage.

(2) The deliverability standard pressure (DSP) to be used in the application of special allocated rules (field rules) shall be defined as 25 pounds less than the average shut-in wellhead pressure of the pool.

(3) The Corporation Commission shall calculate and publish reports of allowable and production quarterly.

(d) Minimum unit allowable of 2,000 mcf/d for the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools. For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools (Pool Nos. 456, 457 and 458) located in Latimer and LeFlore Counties, Oklahoma, the minimum allowable for a drilling and spacing unit in each pool shall be 2,000 mcf/d. For purposes of this Section, the net minimum allowable shall be the gross minimum allowable adjusted for overage or underage according to this Section.

(e) **Double minimum allowable of 300 mcf/d.**

(1) **Compressor and application required.** For all special allocated gas pools except the West Cheyenne Upper Morrow, Purvis Chert, Guymon-Hugoton, Custer City N. Hunton, Sharon W. Morrow, Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, if a drilling and spacing unit has a minimum allowable under (b) of this Section, the operator of a well in the drilling and spacing unit may obtain for the unit a double minimum allowable regardless of any location penalty against a well by installing a compressor on a unit well and applying for a double minimum allowable under (2) of this subsection.

(2) **Request for administrative approval.** To apply for a double minimum allowable, the operator shall submit to the Manager of Production Allowables for the Conservation Division a letter requesting a double minimum allowable and stating the factual basis for the request and the legal description of the well with the compressor.

(f) **Basic allowable.**

(1) **Use of basic allowable for determining overage and underage.** For purposes of determining the amount of overage or underage accrued by a well or drilling and spacing unit, the Conservation Division shall establish on a yearly basis a status factor known as the basic allowable.

(2) **Apportionment of basic allowable.**

(A) **Increased density unit without apportionment of the allowable.** If neither OAC 165:10-13-9 nor an order of the Commission require specific allocation of the unit allowable to each unit well, overage and underage shall be carried on a unit basis.

(B) **Increased density unit with ratable allowables.** If either OAC 165:10-13-9 or an order of the Commission require specific allocation of the unit allowable to each unit well, overage and underage shall be carried on a per well basis. For purposes of computing overage and underage, the basic allowable shall be apportioned to each unit well using the formula for determining each well's ratable allowables for the applicable month under (3) of this subsection. The term "ratable

allowables" refers to a well's share of the unit allowable under the formula apportioning the allowable amongst the unit wells.

(3) **Computation of the basic allowable.** Except as provided in (C) of this paragraph for basic allowable changes, the basic allowable for the calendar year shall be computed as follows:

(A) **For all pools except the Red Oak Pools.** For all pools except the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the basic allowable shall equal the drilling and spacing unit's January allowable for the calendar year.

(B) **For the Red Oak Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro, the basic allowable shall equal the drilling and spacing unit's March allowable for the calendar year.

(C) **Changes in the basic allowable.**

(i) **Test exempt minimum allowable.** If a drilling and spacing unit receives test exempt minimum allowable status as provided in this Section, then the basic allowable shall be a minimum allowable.

(ii) **Test exempt double minimum allowable.** If a drilling and spacing unit receives a test exempt double minimum allowable as provided in this Section, then the basic allowable for the unit shall be a double minimum allowable.

(iii) **Retests.** If the well operator submits to the Conservation Division a retest which is approved by the Conservation Division, then the Conservation Division shall recompute the basic allowable using the retest. Retests are permitted at any time and become effective the first day of the month after acceptance by the Conservation Division.

(g) **Determination of overage and underage.**

(1) **Overage.**

(A) **Drilling and spacing unit without ratable allowables.** If no well in a drilling and spacing unit is subject to a ratable allowable, the current monthly allowable shall be compared with the second prior month's unit production. Production in excess of the current monthly allowable is overage. Aside from any adjustment to the pool allowable required by pool rules, overage shall not reduce any subsequent monthly allowable until accumulated overage exceeds the applicable overage limit under (h) of this Section.

(B) **Drilling and spacing unit subject to ratable allowables.** If any well in a drilling and spacing unit is subject to a ratable allowable, the current monthly ratable allowable for the well shall be compared with the second prior month's production from the well. Production in excess of the ratable allowable is overage. Aside from any adjustment to the pool allowable required by pool rules, the well's overage shall not reduce any subsequent monthly ratable allowable until accumulated overage exceeds the well's overage limit under (h) of this Section.

(2) **Underage.**

(A) **Drilling and spacing unit without ratable allowable.** If no well in a drilling and spacing unit is subject to a ratable allowable under OAC 165:10-13-9, the current monthly allowable for the unit shall be compared with the second prior month's unit production. If production is less than the allowable, the difference between the production and the unit allowable is underage. Aside from any adjustment to the pool allowable required by pool rules, only reinstated cancelled underage under (k) of this Section shall increase any subsequent monthly allowable.

(B) **Drilling and spacing unit with ratable allowables.** In a drilling and spacing unit with ratable allowables, the current monthly ratable allowable for a well shall be compared with the second prior month's production from the well. If production was less than the current monthly ratable allowable, the difference between the production and the ratable allowable is underage. Aside from any adjustment to the pool allowable required by pool rules, only reinstated cancelled underage

under (k) of this Section shall increase any subsequent monthly ratable allowable for the well.

(h) **Overage limits.**

(1) **For all pools Except the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro.** For all pools except the Red Oak Fanshawe, Red Oak Red Oak, and the Red Oak Spiro, the overage limit is six times:

(A) The basic allowable for the drilling and spacing unit, if the overage carried on a unit basis; or

(B) The well's share of the basic allowable for the drilling and spacing unit, if the well receives a ratable allowable.

(2) **For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools, the overage limit is 168 times:

(A) The basic allowable for the drilling and spacing unit, if the overage is carried on a unit basis; or

(B) The well's share of the basic allowable for the drilling and spacing unit, if the well receives a ratable allowable.

(3) **Mandatory curtailment for excessive overage.**

(A) **Single well drilling and spacing unit.** If accumulated overage from a single well drilling and spacing unit exceeds the applicable overage limit, production from the unit shall be curtailed to 25 percent of the monthly allowable until accumulated overage is reduced below the overage limit.

(B) **Multiple well unit without ratable allowables.** In a multiple well drilling and spacing unit without ratable allowables, if accumulated overage for the unit exceeds the applicable overage limit, the unit production shall be curtailed to 25 percent of its monthly allowable until the accumulated overage is reduced below the overage limit.

(C) **Multiple well unit with a ratable allowable.** In a multiple well drilling and spacing unit with one or more wells subject to a ratable allowable, if the accumulated overage for a well exceeds its overage limit, production from the well shall be curtailed to 25 percent of its monthly ratable allowable until the well's accumulated overage is reduced below its overage limit.

(i) **Underage limits.**

(1) **For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools.** For the Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro Pools (Pool Nos. 456, 457 and 458) located in Latimer and LeFlore Counties, Oklahoma, the underage limit is three times the status factor for:

(A) The drilling and spacing unit,

(i) If the unit has only one well, or

(ii) If the unit has multiple wells but no unit well has a ratable allowable; or

(B) The well, if a well has a ratable allowable.

(2) **For all other special allocated gas pools subject to this Section.** For all other special allocated gas pools subject to the Section, the underage limit is six times the status factor for:

(A) The drilling and spacing unit, if the status factor is determined on a unit basis; or

(B) The well, if the well is subject to a ratable allowable.

(j) **Cancellation of underage.**

(1) **Underage in excess of the underage limit.** If accumulated underage exceeds the applicable underage limit, the accumulated underage shall be cancelled.

(2) **Subsequent underage.** After cancellation, underage shall not accrue until after:

(A) The drilling and spacing unit produces a current monthly allowable, if the unit wells share a unit allowable; or

(B) A well with a ratable allowable produces a current monthly ratable allowable.

(k) **Reinstatement of cancelled underage.**

(1) The operator may apply for reinstatement of cancelled underage by:

(A) An application for administrative approval on Form 1010, if filed within six months after cancellation of underage; or

(B) Application, notice, and hearing under OAC 165:5-7-1.

(2) Reinstated cancelled underage shall be available to increase the monthly allowable or ratable allowable for up to one year without cancellation. If reinstated underage is cancelled, the operator may reapply under (1) of this subsection.

(3) For the Guymon-Hugoton special allocated gas pool, the operator of any drilling and spacing unit in such pool which unit has accumulated cancelled underage credited thereto on the records of the Commission prior to July 1, 1998 shall have until January 1, 2000 to file an application with the Commission pursuant to OAC 165:5-7-1 for the reinstatement of such accumulated cancelled underage as credited to such unit prior to July 1, 1998. Upon the filing of such an application, the cause seeking reinstatement of such accumulated cancelled underage shall be diligently prosecuted. In such proceeding for the reinstatement of such accumulated cancelled underage credited to such drilling and spacing unit prior to July 1, 1998, the Commission shall determine the portion of such accumulated cancelled underage which is proper and valid under the special pool allocation rules (field rules) applicable to the Guymon-Hugoton special allocated gas pool and shall reinstate only such portion that is determined to be proper and valid under such special pool allocation rules (field rules). If an application for reinstatement of any such accumulated cancelled underage credited to a drilling and spacing unit on the records of the Commission prior to July 1, 1998 is not filed with the Commission on or before January 1, 2000, such accumulated cancelled underage shall be permanently deleted from the records of the Commission and shall not thereafter be able to be reinstated or used for any other purpose under the special pool allocation rules (field rules) applicable to the Guymon-Hugoton special allocated gas pool.

(l) **Effect of reinstatement of underage on pool allowables.** If cancelled underage has been distributed among the capable wells in the pool, reinstated underage shall not be deducted for the allowables of the capable wells which received distributed cancelled underage.

(m) **Test exempt status.**

(1) **No allowable without test.** For all pools except West Cheyenne Upper Morrow and Purvis Chert, no allowable shall be assigned unless:

(A) **Single well drilling and spacing unit.** The operator submits the required test or the unit has test exempt status under this Section.

(B) **Multiple well drilling and spacing unit.** In a multiple well drilling and spacing unit, the operator of at least one well in the unit submits the required test in accordance with applicable pool rules or the unit is granted test exempt status under this Section.

(2) **Automatic test exempt status.**

(A) **For the West Cheyenne Upper Morrow and Purvis Chert Pool.** For the West Cheyenne Upper Morrow and Purvis Chert, a drilling and spacing unit shall have test exempt status as follows:

(i) **Single well drilling and spacing unit.** In a single well drilling and spacing, the well operator does not submit either an initial or an annual test.

(ii) **Multiple well drilling and spacing unit.** In a multiple well drilling and spacing unit, none of the well operators in the unit submit either an initial or annual test. A test exempt drilling and spacing unit on the West Cheyenne Upper Morrow and Purvis Chert Pools shall have a minimum allowable under the applicable orders establishing and modifying pool rules as opposed to (b) of this Section.

(3) **Test exempt status upon requests for all other pools.** For all other pools except Guymon-Hugoton a drilling and spacing unit shall be test exempt upon written request to the Conservation Division if the potential for the unit does not exceed:

(A) The applicable minimum allowable under this Section.

(B) A double minimum allowable, if the Conservation Division has granted a double minimum to the unit.

(4) **Termination of requested test exempt status.**

(A) **Automatic termination.** Requested test exempt status shall terminate upon:

(i) **Submission of a retest.** Submission of a retest showing that the well has a potential in excess of a test exempt allowable, or;

(ii) **Overproduction.**

(I) **Single well drilling and spacing unit.** If gas production from a single well drilling and spacing unit exceeds a test exempt allowable during any month while the well has test exempt status, the unit shall lose test exempt status beginning with next month following the month with overproduction.

(II) **Multiple well drilling and spacing unit.** If total gas production from a multiple well drilling and spacing unit exceeds the minimum allowable during any month while the unit has test exempt status, the unit shall lose test exempt status beginning with the next month following the month with overproduction.

(B) **Reinstatement of test exempt status after automatic termination.** After termination of test exempt status for overproduction, the Conservation Division shall not reinstate test exempt status until:

(i) The operator requests test exempt status; and

(ii) The allowable year during which overproduction occurred expires.

(n) **Suspension of well allowable calculations under field rules when market demand exceeds supply for Red Oak Fanshawe, Red Oak Red Oak, and Red Oak Spiro pools.** The Commission, upon finding in the market demand hearing that the supply of natural gas from the various separate common sources of supply included in and covered by the Red Oak Fanshawe Pool 456, the Red Oak Red Oak Pool 457, and the Red Oak Spiro Pool 458 is less than such market demand, shall suspend the special field rules calculations for determining allowables for wells in such pools and such suspension shall be effective until such time that the supply of natural gas from these pools exceeds the market demand for such natural gas, and during such suspension the gas allowables for wells in such pools shall be determined under this rule. See Order No. 571714 which issued in Cause CD No. 200902831.

(1) **For existing wells, granting separate allowables and establishing overage status as of the effective date of this rule.** Each well in existence as of the effective date of this rule which is then completed in one or more of the Red Oak Fanshawe Pool 456, Red Oak Red Oak Pool 457, and the Red Oak Spiro Pool 458 shall be deemed an Existing Well for purposes of this rule. Each Existing Well shall receive a full separate allowable. Any total net overage including cancelled underage, accumulated by and assigned to any such drilling and spacing unit, shall be distributed and assigned in equal proportions to the Existing Wells in such drilling and spacing unit. Any such net overage so assigned to an Existing Well shall hereinafter be made up from the separate allowable for such well under the provisions of the Commission's rules applicable to a well in an unallocated gas pool.

(2) **Test requirements and determination of unit allowables for new and existing wells.** Any new well drilled and completed or any Existing Well re-completed into one or more of the Red Oak Fanshawe Pool 456, Red Oak Red Oak Pool 457, and Red Oak Spiro Pool 458 after the effective date of this rule, shall be deemed a New Well for purposes of this rule. The allowable for any New Well or Existing Well as to the applicable pool covered hereby shall be determined using the same allowable formula used by the Commission for the determination of a gas allowable for a capable well or a minimum

well in an unallocated gas pool. **EXCEPTION:** Any Existing Well which is a minimum well shall be exempt from the annual test requirement. If any drilling and spacing unit formed for any common source of supply in any pool covered by this rule contains more than one New Well completed in such common source of supply and such New Wells are classified as gas wells, such New Wells shall share a single unit gas allowable in the same manner as any other gas wells in the same drilling and spacing unit in an unallocated gas pool, unless the Commission grants a separate gas allowable as to production from such pool after proper notice and hearing.

(o) **Suspension of well allowable calculations using field rules when market demand exceeds supply for the Guymon-Hugoton Pool 182.** The Commission, upon finding that the supply of natural gas from Guymon-Hugoton Pool 182 common source of supply is less than the market demand and that the expectations for supply to continue to be less than the market demand as determined in the market demand hearing, will suspend special field rule calculations for determining allowables until such time that the supply of natural gas from this pool exceeds the market demand. See Order No. 571714 which issued in Cause CD No. 200902831.

(1) For allowable purposes, wells which produce less than 450 mcfg per day must conduct a 48 hour shut-in pressure test according to pool rules. For reporting purposes, an operator may submit these data for several wells as an attachment to Form 1017 providing operator name, date of test, well name, location and api number for each well.

(2) For allowable purposes, wells which produce more than 450 mcfg per day must conduct a deliverability test according to pool rules and submitted on Form 1017.

(3) Upon submission of the proper test, the allowable shall be the well's capability to produce.

(p) **Suspension of well allowable calculations using field rules when all wells in the West Cheyenne Upper Morrow gas pool produce less than the pool minimum allowable and the market demand exceeds supply.** The Commission, upon finding that the supply of natural gas from West Cheyenne Upper Morrow Pool 136 common source of supply is less than the market demand and that the expectations for supply to continue to be less than the market demand as determined in the market demand hearing, will suspend special field rule calculations for determining allowables and well allowables will be the wells' capacity to produce up to 2000 mcf per day. See Order No. 571714 which issued in Cause CD No. 200902831. Each well will be exempt from the annual test requirement.

[**SOURCE:** Amended in Rule Making 970000011, eff 7-1-98; Amended in Rule Making 980000033, eff 7-1-99; Amended in Rule Making 200100006, eff 7-1-01; Amended in Rule making 200400006, eff 7-1-04; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-17-10. Unallocated pools [RESERVED]

165:10-17-11. Maximum permitted rates of production for unallocated gas wells

(a) **Scope.**

(1) This Section shall apply to each gas well in unallocated status except as otherwise provided by Commission order. The Commission may establish different production rates by:

(A) Location exception order.

(B) Establishment of pool rules for the common source of supply.

(C) Other order adjusting gas production from the well.

(2) For purposes of this Section, the term "well" shall include any drilling and spacing unit with multiple unallocated gas wells, which do not receive separate maximum permitted rates of production by Commission order.

(3) For the purposes of this Section, the term "allowable formula" shall mean the formula used by the Commission for the determination of the daily rates for capable and minimum wells.

(4) For purposes of this Section, the term "capable well" shall refer to those unallocated gas wells having a wellhead absolute flow potential of 2000 mcf/d or greater. All other wells are minimum wells.

(5) For purposes of this Section, the term "daily natural flow" means the wellhead absolute open flow potential determined in the manner described in OAC 165:10-17-6 and OAC 165:10-17-7.

(b) **Commission authority and responsibility.** Production shall be governed by the provisions of 52 O.S. Section 29. Pursuant to said statute, the Commission has the power and authority to adjust allowables to meet reasonable market demand. The Commission, upon its own application, after notice and hearing, shall establish allowables which may be greater or lesser than those set forth in 52 O.S. Section 29.

(c) **Procedure.**

(1) Allowables for wells other than those provided in subsections (a), (e), (f), and (g) of this Section shall be determined pursuant to a proration hearing held at least annually. The Commission may hold additional proration hearings at shorter intervals if necessary. At least 15 days prior to scheduled annual hearings, the Commission shall publish in a newspaper of general circulation in Oklahoma County, the proposed allowable formula for the next proration period. The annual proration hearings shall be held at least 30 days prior to the proration period for which the allowable is being determined. Such hearing shall be for the purpose of gathering comments and hearing testimony from all interested parties concerning the determination of reasonable market demand for the next proration period. As a guideline, but not to the exclusion of any other information that the Commission deems pertinent, the following may be considered by the Commission in determining reasonable market demand and corresponding allowables:

(A) Production from prior years.

(B) Production from the most recent proration period.

(C) Wellhead open flow potentials.

(D) New wells, recompletions, temporarily abandoned wells and plugged wells.

(E) Gas which is available but is not being produced at the present time.

(F) Changes in existing gas markets, forecasts, and new markets for Oklahoma gas.

(G) State-wide gas production and the portion thereof attributable to unallocated gas wells.

(H) Overproduction and underproduction from the preceding proration period.

(2) After a proration hearing, the Commission shall publish in a newspaper of general circulation in Oklahoma County, the allowable formula, no later than 15 days prior to the proration period for which the allowable formula is determined.

(d) **Emergency allowables.**

(1) When the Commission determines that an emergency gas supply situation exists, the Commission may establish an emergency allowable. The emergency allowable shall provide for the protection of correlative rights including those relating to minimum wells and penalized wells.

(2) The Commission may extend or change the emergency allowable for as long as an emergency exists. However, any authorized extension of the emergency allowable shall be by order after notice and hearing.

(e) **Exceptions.** Upon application, notice, and hearing, the Commission may establish a different allowable for good cause shown.

(f) **Exclusion for hardship and distressed wells.** The allowable established under this Section shall not limit rates established by special order for those wells classified as hardship or distressed wells.

(g) **Discovery gas well.**

(1) For thirty (30) months from the date of first production, a discovery gas well, as defined in this subsection, subject to the provisions of this Section, shall have a production allowable which shall be the greater of one thousand three hundred (1,300) mcf/d or sixty-five percent (65%) of the absolute open flow (AOF) as specified by the Corporation Commission. Such discovery well allowable shall not be available for any discovery gas well wherein two (2) or more separate common sources of supply are commingled and one (1) common source of supply would not qualify a new gas well as a discovery gas well, as defined in this Section.

(2) Drilling and spacing units which are downspaced after June 1, 1997, shall not qualify for the discovery gas well allowable.

(3) For purposes of this subsection, "discovery gas well" shall mean a new gas well, which is not an off-pattern well, is the first well completed in a common source of supply within a drilling and spacing unit and is at least one (1) mile from all existing gas wells which are completed in the same common source of supply. In the absence of spacing, a discovery well shall be the first well in the governmental section completed in a common source of supply, provided that the discovery gas well shall not be drilled closer than one thousand three hundred twenty (1,320) feet from the boundaries of the governmental section and is at least one (1) mile from all existing gas wells which are completed in the same common source of supply.

(h) **Exclusion for reservoir dewatering.** Allowables shall not apply, regardless of unit size, in the instance of production of gas by reservoir dewatering to extract said gas from reservoirs having initial water saturations at or above fifty (50%) percent.

(i) **Minimum compliance.**

(1) The Conservation Division shall monitor well production at least annually. The allowable for a well shall be based on the product of the number of days in the proration period, multiplied by the applicable allowable formula, provided that said product shall be reduced for overproduction as provided by this Section or by any penalty or limitation on production imposed by applicable Commission order.

(2) Any overproduction existing at the end of the calendar year shall be applied against the allowable for the next calendar year. Furthermore, the overproduced well shall be required to make up overproduction within the first six months of the next calendar year. If the overproduction is not made up within that time period, the flow rate shall not exceed ten percent of the then current allowable until the overproduction is made up.

[**Source:** Amended at 9 Ok Reg 3969, eff 8-28-92 (emergency); Amended at 10 Ok Reg 1275, eff 9-25-92 (emergency); Amended at 10 Ok Reg 1579, eff 5-13-93; Amended in Rule Making 97000002, eff 7-1-97; Amended in Rule Making 980000011, eff 7-1-98; Amended in Rule Making 200200017, eff 7-1-02; Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003); Amended at 30 Ok Reg 1041, eff. 7-1-13 (RM 201300001)]

165:10-17-12. New proposed well classification for the priority schedule

(a) Any common purchaser as defined in 52 O.S. 1981, Section 240 shall purchase all the gas which may be offered for sale and which may reasonably be reached by its trunk lines or gathering lines, without discrimination in favor of one producer as against another or in favor of any one source of supply as against another, except as authorized by the Commission under (b) of this Section.

(b) In the interest of the prevention of waste and protection of correlative rights, the following priority schedule shall be implemented by any first purchaser of gas whenever the permitted production from all wells in any common source of supply in its system in this State, including gas which is processed, is in excess of that purchaser's reasonable market demand; provided, however, if the first purchaser does not contractually control

wellhead production, the first taker of gas shall be responsible for implementation of the following priority schedule.

(1) Priority One - Hardship and distressed wells.

(2) Priority Two - Enhanced recovery wells.

(3) Priority Three - Wells producing casinghead gas and associated gas.

(c) With respect to all gas not identified in (b) of this Section, the collective market demand of multiple common purchasers on each pipeline system for natural gas production from each well and each common source of supply in this state shall be deemed adequate to meet statutory purchasing requirements unless the Commission, upon its own motion or upon verified application by any interested party and after notice and hearing, as hereinafter provided, shall determine that differing obligations shall be imposed upon any common purchaser in order to protect correlative rights, the interest of the public or otherwise meet the requirements of applicable law.

(d) When permitted production of gas from all Priority 1, 2, and 3 wells from which a purchaser or taker is required to take exceeds the market demand of said purchaser or taker, all reductions in gas purchases or takes from wells in each priority shall be ratable. All production from the lower priority wells shall be shut-in before production from any well in the next higher priority is curtailed.

(e) Any well which meets the definition of more than one priority shall be assigned the higher priority.

(f) When there is more than one purchaser or taker involved in the taking of gas from a well into any purchaser's system, all purchasers and takers within that system shall be responsible for compliance with this Section.

(g) Upon a verified application of the Director of the Conservation Division or any other person, the Commission, after notice and hearing, may determine if gas has been ratably purchased or taken from a common source of supply on a system-wide basis in accordance with this Section without avoidable waste and with equitable participation in production and markets by all operators and other interested parties.

(h) First purchasers or takers of gas produced from Priority 1, 2, or 3 wells, who anticipate curtailing production from such wells, shall file by the twentieth day of each month nominations of requirements for gas to be purchased and/or used by them during the following month (Form 1004B). Nominations shall be made according to priorities established in (b) of this Section. Curtailments of production and acceptance of deliveries of gas shall be performed in accordance with (a) and (b) of this Section.

(i) Any interested party may file an application requesting that the Commission, for good cause shown, authorize limited deviation from the general priority schedule provided under (b) of this Section. The Commission, on its own motion, may initiate a review of the continued need for such a limited deviation. After notice and hearing, the Commission may authorize limited deviation upon finding that the same is necessary in order to prevent waste, protect correlative rights, and is otherwise required by the public interest or authorized by law.

[**Source:** Amended at 12 Ok Reg 2045, eff 7-1-95]

165:10-17-13. Use of gas for carbon black

Gas may not be used for the manufacture of carbon black or similar products predominately carbon, except as specifically authorized by the Commission after notice and hearing.

165:10-17-14. Waste of tail gas at gasoline plants

The duty, obligation, and jurisdiction of the Commission to prevent waste of tail gas where an additional market is available shall not be circumvented by any exclusive provisions in private contracts between the owners and the purchasers of tail gas.

165:10-17-15. Gas removed from storage

The rules relating to gas production from pools shall not apply to gas being removed from storage except and unless waste is involved.

165:10-17-16. Reports

A calendar year shall constitute the accounting period for each unallocated gas well. At the end of each calendar year, the Conservation Division will mail an original and one copy of Machine Accounting Form 1007A (Unallocated Gas Well Survey) to the operator, and the operator shall complete and file the original form with the Conservation Division on or before the following February 15th and retain the copy for his own use.

[**Source:** Amended in Rule Making 200200017, eff 7-1-02]

SUBCHAPTER 19. NATURAL GAS POLICY ACT DETERMINATION [REVOKED]

165:10-19-1. Definitions [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-2. Applications for NGPA determination [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-3. Application for additional well in existing proration unit [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-4. Notice of application; service of notice [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-5. Procedures for protest, administrative consideration, and hearing [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

165:10-19-6. Stripper well determination [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

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SUBCHAPTER 21. APPLICATIONS FOR TAX EXEMPTIONS

PART 1. TERTIARY RECOVERY PROJECT [REVOKED]

PART 2. ENHANCED RECOVERY PROJECT [REVOKED]

PART 3. HORIZONTALLY DRILLED PRODUCTION WELLS [REVOKED]

PART 4. DELETERIOUS SUBSTANCES [REVOKED]

PART 6. PRODUCTION ENHANCEMENT PROJECTS

PART 7. RE-ESTABLISHMENT OF PRODUCTION FROM AN INACTIVE WELL

PART 8. DEEP WELLS

PART 9. NEW DISCOVERY WELLS

PART 11. HORIZONTALLY DRILLED PRODUCING WELLS

PART 13. INCREMENTAL PRODUCTION FROM ENHANCED RECOVERY PROJECTS

SUBCHAPTER 21. APPLICATIONS FOR TAX EXEMPTIONS

PART 1. TERTIARY RECOVERY PROJECT [REVOKED]

165:10-21-1. Tertiary recovery project certification [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 2. ENHANCED RECOVERY PROJECT [REVOKED]

165:10-21-2. Gross production tax exemption for enhanced recovery project [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 3. HORIZONTALLY DRILLED PRODUCTION WELLS [REVOKED]

165:10-21-3. Qualification and application for exemption from the levy of gross production tax on horizontally drilled production wells [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 4. DELETERIOUS SUBSTANCES

165:10-21-4. Recycling, reuse, and ultimate destruction of deleterious substances [REVOKED**]**

[SOURCE: Revoked in rule making 200000009, eff 5-11-01]

PART 6. PRODUCTION ENHANCEMENT PROJECTS

165:10-21-21. General

Exemption from the levy of gross production tax pursuant to 68 O.S. Section 1001(G) on the incremental production which results from a production enhancement project with a project beginning date on or after July 1, 1994, and prior to July 1, 2017, shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and Oklahoma Tax Commission pursuant to 68 O.S. Section 1001(N)(1).

[**SOURCE:** Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1809 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-22. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Base production" means the average monthly amount of production for the twelve-month (12) period immediately prior to the commencement of the project or the average monthly amount of production for the twelve-month period immediately prior to the commencement of the project less the monthly rate of production decline for the project for each month beginning one hundred eighty (180) days prior to the commencement of the project. The monthly rate of production decline shall be equal to the average extrapolated monthly decline rate for the twelve-month period immediately prior to the commencement of the project based on the production history of the well. If the well or wells covered by the application had production for less than the full twelve-month period prior to the filing of the application for the production enhancement project, the base production shall be the average monthly production for the months during that period that the well or wells produced.

"Effective date" means the project beginning date for the production enhancement project.

"Exemption period" means a period of twenty-eight (28) months from the date of first sale after completion of the production enhancement project; provided, however, that the exemption in this Part shall not apply to production occurring on or after July 1, 2017.

"Incremental production" means the amount of crude oil, natural gas or other hydrocarbons which are produced as a result of the production enhancement project in excess of the base production.

"Production enhancement project" means: for production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2017, "production enhancement project" means any workover as defined in this Section, recompletion as defined in this Section, reentry of plugged and abandoned wellbores, or addition of well or field compression.

"Recompletion" means: for production enhancement projects having a project beginning date on or after July 1, 1997, and prior to July 1, 2017, "recompletion" means any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geologic interval not currently completed or producing in such existing oil or gas well within the same or a different geologic formation.

"Workover" means any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. For production enhancement projects having a project beginning date on

or after July 1, 1997, and prior to July 1, 2017, "workover" includes, but is not limited to, the following: acidizing; reperforating; fracture treating; sand/paraffin/scale removal or other wellbore cleanouts; casing repair; squeeze cementing; installation of compression on a well or group of wells or initial installation of artificial lifts on oil and/or gas wells, including plunger lifts, rod pumps, submersible pumps and coiled tubing velocity strings; downsizing existing tubing to reduce well loading; downhole commingling; bacteria treatments; upgrading the size of pumping unit equipment; setting bridge plugs to isolate water production zones; or any combination thereof. "Workover" shall not mean the routine maintenance, routine repair, or like-for-like replacement of downhole equipment such as rods, pumps, tubing, packers, or other mechanical devices.

[**SOURCE:** Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-23. Qualification procedure

The well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall apply for qualification of the production enhancement project and incremental production, at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, a copy of the approved application shall be available to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-21-24. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission approves the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A copy of the application approved by the Corporation Commission certifying the well as a production enhancement project.

(2) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(3) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission application, a notarized affidavit, signed by the party named in the application must be filed, authorizing the applicant to apply for the refund.

(b) **No rebate for production occurring prior to July 1, 2003; claim limitation.** Effective July 1, 2014, no refund of gross production taxes shall be claimed for oil and gas production exempt from gross production taxes pursuant to 68 O.S.

Section 1001(G) for production occurring prior to July 1, 2003. Claims for rebate filed with the Oklahoma Tax Commission shall be subject to limitations pursuant to Title 68 O.S., Sections 1001(L) and 1001(M).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 7. RE-ESTABLISHMENT OF PRODUCTION FROM AN INACTIVE WELL

165:10-21-35. General

Exemption from the levy of gross production tax pursuant to 68 O.S. Section 1001(F) on the reestablishment of production from an inactive well shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and Oklahoma Tax Commission pursuant to 68 O.S. Section 1001(N)(1).

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-21-36. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Effective date" means the date on which the reestablishment of production has occurred.

"Exemption period" means a period of twenty-eight (28) months from the date upon which production from an inactive well is reestablished; provided, however, that the exemption in this Part shall not apply to production occurring on or after July 1, 2017.

"Inactive well" means a well which may be defined under one (1) of the following three (3) categories:

(A) A well which after July 1, 1994, experiences mechanical failure or loss of mechanical integrity, as defined by the Corporation Commission, including but not limited to, casing leaks, collapse of casing or loss of equipment in a wellbore, or any similar event which causes cessation of production, shall be considered an inactive well. For use within this sub-paragraph "mechanical failure" means a well which experiences mechanical failure or loss of mechanical integrity because of, but not limited to, casing leaks, collapse of casing or loss of equipment in a wellbore, or any similar event which results in a workover of the well and cessation of production as evidenced by the use of a workover rig or other mechanical device being placed over the well to repair the well or equipment. This applies to wells for which work to reestablish production began on or after July 1, 1994, and for which production is reestablished prior to July 1, 2017.

(B) A well on which work to reestablish production commenced on or after July 1, 1994, and for which production is reestablished on or after July 1, 1997, and prior to July 1, 2017, that has not produced oil, gas or oil and gas for a period of not less than one (1) year as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well's status.

(C) A well on which work to reestablish production commenced on or after July 1, 1994, and for which production is reestablished prior to July 1, 1997, that has not produced oil, gas or oil and gas for a period of not less

than two (2) years as evidenced by the appropriate forms on file with the Oklahoma Corporation Commission reflecting the well's status.

[**SOURCE:** Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1810 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-37. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well and production at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, a copy of the approved application shall be available to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-21-38. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission grants the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A copy of the application approved by the Corporation Commission certifying the well as an inactive well for which production has been reestablished.

(2) A copy of an approved OTC Form 320C that shows the date of the re-establishment of production of oil and/or gas.

(3) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(4) If the refund request is filed by any person other than the party named in the Oklahoma Corporation Commission application, a notarized affidavit, signed by the party named in the application must be filed, authorizing the applicant to apply for the refund.

(b) **No rebate for production occurring prior to July 1, 2003; claim limitation.** Effective July 1, 2014, no refund of gross production taxes shall be claimed for oil and gas production exempt from gross production taxes pursuant to 68 O.S. Section 1001(F) for production occurring prior to July 1, 2003. Claims for rebate filed with the Oklahoma Tax Commission shall be subject to limitations pursuant to Title 68 O.S., Sections 1001(L) and 1001(M).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[**SOURCE:** Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended in Rule Making 200600012, eff 7-

1-2006; Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 8. DEEP WELLS

165:10-21-45. General

(a) **General provisions.** Exemption from the levy of gross production tax on the production of gas, oil, or gas and oil from wells certified as being "Deep Wells" set out in 68 O.S. § 1001(H) shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to 68 O.S. § 1001(N)(1).

(b) **Definitions.** For purposes of qualifying for the exemption, "**depth**" means the length of the maximum continuous string of drill pipe utilized between the drill bit face and the drilling rig's kelly bushing.

(c) **Exemption for wells spudded between July 1, 2002, and July 1, 2005, drilled to a depth of fifteen thousand (15,000) feet or greater.** Deep wells spudded between July 1, 2002, and July 1, 2005, and drilled to a depth of fifteen thousand (15,000) feet or greater shall be exempt from the gross production tax, beginning from the date of first sale, for a period of forty-eight (48) months, on production which occurs prior to July 1, 2011. Production on or after July 1, 2011, and before July 1, 2015, from wells qualifying for this exemption shall be taxed at a rate of four percent (4%) until the expiration of forty-eight (48) months from the date of first sale.

(d) **Exemption for wells spudded between July 1, 1997, and July 1, 2005, drilled to a depth of twelve thousand five hundred (12,500) feet or greater.** Deep wells spudded between July 1, 1997, and July 1, 2005, and drilled to a depth of twelve thousand five hundred (12,500) feet or greater shall be exempt from the gross production tax, beginning from the date of first sale, for a period of twenty-eight (28) months; provided, however, that the exemption provided by this subsection shall not apply to production occurring on or after July 1, 2017.

(e) **Additional exemptions for deep wells.** Production from deep wells spudded and drilled as noted below shall be eligible for an exemption from the gross production tax which shall begin from the date of first sale, and vary as to duration in relation to the depth of the well.

(1) **12,500 to 14,999 feet and spudded between July 1, 2005 and July 1, 2015.** The duration of the exemption for wells drilled to this depth is twenty-eight (28) months; provided, however, that the exemption provided by this paragraph shall not apply to production occurring on or after July 1, 2017.

(2) **15,000 to 17,499 feet and spudded between July 1, 2005 and July 1, 2011.** The duration of the exemption for wells drilled to this depth is forty-eight (48) months on production which occurs prior to July 1, 2011. Production on or after July 1, 2011, and before July 1, 2015, from wells qualifying for this exemption shall be taxed at a rate of four percent (4%) until the expiration of forty-eight (48) months from the date of first sale.

(3) **15,000 to 17,499 feet and spudded between July 1, 2011, and July 1, 2015.** The tax levied on the production from wells drilled to this depth shall be reduced to a rate of four percent (4%) for a period of forty-eight (48) months from the date of first sale; provided, however, the reduced rate provided by this paragraph shall not apply to production occurring during or after the first full month following November 17, 2017.

(4) **17,500 feet or greater and spudded between July 1, 2002 and July 1, 2011.** The duration of the exemption for wells drilled to this depth is sixty (60) months on production which occurs prior to July 1, 2011. Production on or after July 1, 2011, and before July 1, 2015, from wells qualifying for this exemption shall be taxed at a rate of four percent (4%) until the expiration of sixty (60) months from the date of first sale.

(5) **17,500 feet or greater and spudded between July 1, 2011, and July 1, 2015.** The tax levied on the production from wells drilled to this depth shall be reduced to a rate of four percent (4%) for a period of sixty (60) months from the date of first sale; provided, however, the reduced rate provided by

this paragraph shall not apply to production occurring during or after the first full month following November 17, 2017.

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 970000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 24 Ok Reg 1811 (RM 200700004), eff 7-1-2007; Amended at 26 Ok Reg 2498, eff 7-11-09 (RM 200900001); Amended at 27 OK Reg 2128, eff 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff 7-11-11 (RM 201000007); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-46. Definitions [REVOKED]

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Revoked in Rule Making 97000025, eff 7-1-98]

165:10-21-47. Qualification procedure

An OCC Form 1002A Completion Report accepted by the Oklahoma Corporation Commission reflecting that a well was spudded during the applicable time period and drilled to the prescribed depth appearing in OAC 165:10-21-45 constitutes approval by the Commission of an application for qualification for the exemption.

[**SOURCE:** Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Amended at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001)]

165:10-21-47.1. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission accepts an OCC Form 1002A Completion Report consistent with the provisions of OAC 165:10-21-47, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) An OCC Form 1002A Completion Report accepted by the Corporation Commission.

(2) A copy of an approved OTC Form 320A that shows date of first sale of production.

(3) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(4) If the refund request is filed by any person other than the party named in the application, a notarized affidavit, signed by the party named in the application must be filed, authorizing the applicant to apply for the refund.

(b) **No rebate for production occurring prior to July 1, 2003; claim limitation.** Effective July 1, 2014, no refund of gross production taxes shall be claimed for oil and gas production exempt from gross production taxes pursuant to 68 O.S. Section 1001(H) for production occurring prior to July 1, 2003. Claims for rebate filed with the Oklahoma Tax Commission shall be subject to limitations pursuant to Title 68 O.S., §1001(L) and §1001(M).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended in Rule Making 200600012, eff 7-

1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-48. Audit requirements [REVOKED]

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Revoked in Rule Making 200300001, eff 7-1-03]

165:10-21-49. Certificate of investment to be filed by the operator [REVOKED**]**

[SOURCE: Added at 12 Ok Reg 491, eff 1-1-95 (emergency); Added at 12 Ok Reg 1605, eff 7-1-95; Revoked at 13 Ok Reg 2933, eff 7-11-96]

PART 9. NEW DISCOVERY WELLS

165:10-21-55. General

(a) Exemption from the levy of gross production tax on the production of gas, oil, or gas and oil from wells spudded or reentered between July 1, 1995 and July 1, 2015, which qualify as a new discovery well pursuant to Title 68, Section 1001(I), shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to Title 68, Section 1001(N)(1). Such exemption from the gross production tax shall be from the date of first sales for a period of twenty-eight (28) months; provided, however, that the exemption in this Part shall not apply to production occurring on or after July 1, 2017.

(b) **"New discovery"** means production of oil, gas or oil and gas from:

(1) A well, spudded or reentered on or after July 1, 1997, and prior to July 1, 2015, which discovers crude oil in paying quantities and is located more than one mile from the nearest oil well producing from the same producing interval of the same formation.

(2) A well, spudded or reentered on or after July 1, 1997, and prior to July 1, 2015, which discovers crude oil in paying quantities beneath current production in a deeper producing interval located more than one mile from the nearest oil well producing from the same deeper producing interval.

(3) A well, spudded or reentered, on or after July 1, 1997, and prior to July 1, 2015, which discovers natural gas in paying quantities and is located more than two miles from the nearest gas well producing from the same producing interval.

(4) A well, spudded or reentered, on and after July 1, 1997, and prior to July 1, 2015, which discovers natural gas in paying quantities beneath current production in a deeper producing interval that is more than two miles from the nearest gas well producing from the same deeper producing interval.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1811, eff 7-1-2007 (RM 200700004); Amended at 27 OK Reg 2128, eff 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-56. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Effective date" means the date the well was spudded or the beginning date for a re-entered well.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98]

165:10-21-57. Qualification procedure

The well operator or one of the working interest owners, on behalf of the well operator and the other owners of the well, shall apply for qualification of the well at the Oklahoma Corporation Commission on OCC Form 1534.

(1) OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, an approved copy shall be available to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-21-58. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Oklahoma Corporation Commission approves the application, the operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A copy of the application approved by the Corporation Commission certifying the well as a new discovery well spudded or re-entered between July 1, 1995 and July 1, 2015.

(2) A copy of an approved OTC Form 320A that shows date of first sale of production.

(3) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(4) If the refund request is filed by any person other than the party named in the application, a notarized affidavit, signed by the party named in the application must be filed, authorizing the applicant to apply for the refund.

(b) **No rebate for production occurring prior to July 1, 2003; claim limitation.** Effective July 1, 2014, no refund of gross production taxes shall be claimed for oil and gas production exempt from gross production taxes pursuant to 68 O.S. Section 1001(I) for production occurring prior to July 1, 2003. Claims for rebate filed with the Oklahoma Tax Commission shall be subject to limitations pursuant to Title 68 O.S., Sections 1001(L) and 1001(M).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-59. Audit requirements [REVOKED]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Revoked in Rule Making 200300001, eff 7-1-03]

PART 11. HORIZONTALLY DRILLED PRODUCING WELLS

165:10-21-65. General

Exemption from the levy of Gross Production Tax on horizontally drilled producing wells set out in 68 O.S. § 1001(E) shall be determined according to the provisions of this Part, which have been jointly adopted by the Oklahoma Corporation Commission and the Oklahoma Tax Commission pursuant to law. [See: 68 O.S. §1001(N)(1)]

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended at 28 Ok Reg 1949, eff 7-11-11 (RM 201000007)]

165:10-21-66. Definitions

In addition to terms defined in 165:10-1-2, the following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Angle of deviation" means that angle in which a wellbore may deviate from the vertical.

"Date of completion of a gas well" means the date that gas is capable of being delivered to a pipeline purchaser.

"Date of completion of an oil well" means the date that the well first produces into the lease tanks through permanent well head equipment.

"Effective date" means that the first production must have commenced after July 1, 2002 and before July 1, 2011, or that the first production must have commenced on or after July 1, 2011, and before July 1, 2015.

"Horizontal displacement" means that distance drilled into the pay zone of a formation at an angle exceeding seventy (70) degrees.

"Horizontally drilled payout" means the point at which gross working interest revenue from the horizontally drilled well equals the cost of drilling and completing such well.

"Horizontally drilled well" means an oil, gas, or oil and gas well drilled or completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) feet into the pay zone of the formation.

"Project payback" shall be determined as of the date of the completion of the well and shall not include any expenses beyond the completion date of the well, and is subject to the approval of the Oklahoma Tax Commission.

"True vertical depth" means that depth measured from the surface perpendicular to the surface.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1811 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

165:10-21-67. Qualification procedure

The well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, may apply for qualification of the production from horizontally drilled wells at the Oklahoma Corporation Commission on OCC Form 1534. In lieu of the OCC Form 1534, an OCC Form 1002A Completion Report accepted by the Commission reflecting that the well is a horizontally drilled producing well as addressed in this Part constitutes approval by the Commission of an application for qualification for the exemption.

(1) If an OCC Form 1534 is submitted to the Commission, such form shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission for review.

(2) If the Department approves the application, a copy shall be available to the operator.

(3) If the application is denied or refused, or approval is delayed beyond sixty (60) days, the applicant may seek review by application, notice and hearing.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

165:10-21-68. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Commission approves the application or accepts an OCC Form 1002A Completion Report consistent with the provisions of OAC 165:10-21-67, the well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A copy of the approved application or OCC Form 1002A Completion Report accepted by the Corporation Commission.

(2) A copy of an approved OTC Form 320A that shows the date of initial production.

(3) A properly completed OTC Form 328 Gross Production 841/495 Refund Report.

(4) If the refund request is filed by any person other than the party named in the application, a notarized affidavit, signed by the party named in the application must be filed, authorizing the applicant to apply for the refund.

(b) **No rebate for production occurring prior to July 1, 2003; claim limitation.** Effective July 1, 2014, no refund of gross production taxes shall be claimed for oil and gas production exempt from gross production taxes pursuant to 68 O.S. Section 1001(E) for production occurring prior to July 1, 2003. Claims for rebate filed with the Oklahoma Tax Commission shall be subject to limitations pursuant to Title 68 O.S., Sections (1001)(E)(2) and (1001)(L). Claims for refunds for the production periods within the fiscal years ending June 30, 2010, and June 30, 2011, shall be filed with and received by the Oklahoma Tax Commission no later than December 31, 2011.

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[**SOURCE:** Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-69. Time periods for exemption from gross production tax levied on horizontally drilled producing wells

(a) **General provisions.** The exemption for horizontally drilled wells qualified pursuant to this Part shall be determined as set out below in this Section.

(b) **Forty-eight (48) month exemption-production prior to July 1, 2011, which commenced after July 1, 2002.** For a horizontally drilled well producing oil, gas, or oil and gas prior to July 1, 2011, which production commenced after July 1, 2002, the duration of the exemption from the project beginning date until project payback is achieved may not exceed a period of forty-eight (48) months commencing with the date of initial production from the horizontally drilled well. [See: 68 O.S. Section 1001(E)(1)]

(c) **Forty-eight (48) month exemption – production commenced on or after July 1, 2011, and before July 1, 2015.** The tax levied on oil, gas, or oil and gas production from a horizontally drilled well, which production commenced on or after July 1, 2011, and before July 1, 2015, shall be reduced to a rate of one percent (1%) for a period of forty-eight (48) months commencing with the date of

initial production from the horizontally drilled well; provided such production occurring on or after July 1, 2017, for the remainder of such forty-eight month period shall be subject to a reduced rate of four percent (4%); further provided, any reduced rate provided by this subsection shall not apply to production occurring during or after the first full month following November 17, 2017. [See: 68 O.S. Section 1001(E)(3)]

[SOURCE: Added in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1812 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 13. INCREMENTAL PRODUCTION FROM ENHANCED RECOVERY PROJECTS

165:10-21-75. General

Exemption from the levy of gross production tax on the incremental production of oil or other liquid hydrocarbons attributable to the working interest owners of an enhanced recovery project shall be determined according to the provisions of this Part, 68 O.S. §1001(D) and other applicable sections of such statute. The provisions of 68 O.S. §1001(D) do not apply to any enhanced recovery project using fresh water as the primary injectant, except when using steam. The exemption granted pursuant to 68 O.S. §1001(D) shall not apply to any production upon which a tax is paid at a rate of two percent. [See: 68 O.S. §1001(O)(2)].

[**SOURCE:** Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-21-76. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Base production amount" means the average monthly amount of production for the twelve (12) month period immediately prior to the project beginning date minus the monthly rate of production decline for the project or property for each month beginning one hundred eighty (180) days prior to the project beginning date.

"Completion date" means the date a well is first capable of being used for the injection of liquids, gases or other matter, or is capable of producing crude oil or other liquid hydrocarbons through permanent wellhead equipment.

"Enhanced recovery project costs" means the incremental project costs that are allowed as payback factors in determining the exemptions from the levy of gross production tax of project incremental production.

"Incremental production" means the amount of crude oil or other liquid hydrocarbons which are produced during an approved enhanced recovery project and which are in excess of the base production amount of crude oil or other liquid hydrocarbons.

"Incremental working interest revenue" means the gross value of the incremental production, less the royalty interest therein.

"Monthly rate of production decline" means a rate equal to the average extrapolated monthly decline rate for the twelve (12) month period immediately prior to the project beginning date as determined by the Commission, based on the production history of the field, its current status, and sound reservoir engineering principles.

"Project beginning date" means the date on which the injection of liquids, gases or other matter begins on an enhanced recovery project.

"Project payback or payout" means that point at which the incremental working interest revenue from the enhanced recovery project equals the enhanced project costs. Project payback shall be determined as of the date of the completion of

the well and shall not include any expenses beyond the completion date of the well, and is subject to the approval of the Tax Commission.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1812 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-21-77. Qualification procedure

The provisions of this Section establish criteria for determining if an operator of an enhanced recovery project has met the required conditions to qualify the incremental production from such project for the exemption from the Gross Production Tax. [**See:** 68 O.S. §1001(D)]

(1) **Administrative approval and determination.** An operator seeking an exemption of incremental production from the gross production tax shall make application to the Oklahoma Corporation Commission on OCC Form 1139 for a determination that such project qualifies, a determination of the starting date, and of the base production amount.

(A) OCC Form 1139 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission. If the application is approved, a copy shall be available to the operator. If the application is denied or refused, or approval is delayed beyond sixty (60) days, the operator may seek review by application, notice and hearing.

(B) To obtain the tax exemption, the operator shall forward a copy of the approved application to the Oklahoma Tax Commission, together with any other data required by that agency.

(2) **Tax Commission approval of exemption.** An operator desiring an exemption from the gross production tax shall make application by letter to the Audit Division, Oklahoma Tax Commission. Such application shall be accompanied by:

(A) A copy of the application approved by the Corporation Commission containing a determination of the project beginning date, base production amount and project payback.

(B) The ratio of working interest/royalty interest in the well. Only the incremental production attributable to the working interest owners shall be exempted from the gross production tax. For purposes of this exemption, overriding royalty shall be included in working interest.

(C) A schedule of production, by month, of the gross amounts of crude oil or other liquid hydrocarbons produced, and the gross values thereof, from the project beginning date until the date application is made to the Tax Commission.

(D) OTC Forms 320A, 320C, and 320U, as are necessary, to set up the OTC Production Units, to request merge numbers, and to show the entity who will remit taxes.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003)]

165:10-21-78. Recovery of costs allowed as payback factors

(a) **Secondary recovery project, project beginning date on or after July 1, 2000, and before July 1, 2017.** For any secondary recovery project approved or having an initial project beginning date on or after July 1, 2000, and before July 1, 2017, any incremental production attributable to the working interest owners which results from such secondary recovery project shall be exempt from the gross production tax levied pursuant to 68 O.S. §1001 for a period not to exceed five (5) years from the initial project beginning date or for a period ending upon the termination of the secondary recovery process, whichever occurs first; provided,

however, that the exemption in this subsection shall not apply to production occurring on or after July 1, 2017. [Applicant may omit payback report for such secondary recovery projects.]

(b) **Tertiary enhanced recovery project, project beginning date on or after July 1, 1993 and before July 1, 2017.** For any tertiary enhanced recovery project with a project beginning date on or after July 1, 1993, and before July 1, 2017, allowable enhanced recovery project costs shall include only incremental capital costs and incremental operating expenses, excluding administrative expenses. The capital expenses of pipelines constructed to transport carbon dioxide to a tertiary recovery project shall not be included in determining project payback. The period for project payback shall not exceed ten (10) years from the project beginning date; provided, however, that the exemption in this subsection shall not apply to production occurring on or after July 1, 2017.

(c) **Excluded costs.** The cost of tank batteries, meters, pipelines or other external equipment shall not be included in allowable enhanced recovery project costs. Allowable costs shall be determined using generally accepted accounting principles such as outlined in the "Council of Petroleum Accountants Society (COPAS) - Accounting Procedure Form for Joint Operations" and "COPAS Bulletin No. 16", or subsequent revisions thereto.

[**SOURCE:** Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 97000025, eff 7-1-98; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1813 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-79. Responsibility for filing and payment of taxes

(a) **Responsibility for reporting; reporting; forms required.** The operator of a qualifying project will have primary responsibility for filing OTC Form 300-R-7-81, Gross Production Tax Monthly Tax Report, and for remitting gross production and petroleum excise taxes on project production controlled by the operator. Working interest owners who take-in-kind will be responsible for filing Gross production Monthly Tax Reports, unless the take-in-kind owner has made an agreement with his purchaser or the operator to report and remit on his behalf. A take-in-kind interest owner must submit, through the project operator, a Form 320, showing the disposition of his share of production. Purchasers may report taxes on project production with the approval of the Tax Commission, provided whenever there are multiple purchasers from a project, each reporting purchaser must report his allocated share of production, incremental production, and any exempt interest. All persons remitting taxes must comply with Tax Commission security requirements.

(b) **Valuation of incremental production.** When an operator or a single purchaser files the gross production tax reports and remits taxes, the incremental production will be valued at the volume-weighted average price per barrel of all crude oil or other liquid hydrocarbons produced from the project during the month. When multiple purchasers file the gross production tax reports and remit taxes, the incremental production will be valued at the volume-weighted average price per barrel purchased for the month, by each purchaser individually.

(c) **Method of computing production, base production amount and incremental production.**

(1) Frac oil recovered must be excluded as a Code 07 exemption. Frac oil will not be counted as part of the project base production amount, nor as incremental production.

(2) Incremental production will be deducted next as a Code 11 exemption.

(3) Exempt interests will be deducted next, in order of exemption code, as a decimal equivalent of the amount and value of production remaining after subtraction of the frac oil and incremental production.

(d) Well operators are advised to contact the Oklahoma Tax Commission concerning required annual reporting.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96]

165:10-21-80. Expiration of exemption for incremental production

For secondary recovery projects approved prior to July 1, 2017, and tertiary recovery projects approved prior to July 1, 2017, once the gross working revenue equals the enhanced recovery project cost, the exemption of incremental production shall end and the Oklahoma Tax Commission shall resume collection of the Gross Production Tax thereon.

[SOURCE: Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1813, eff 7-1-2007 (RM 200700004); Amended at 27 OK Reg 2128, eff 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 14. PRODUCTION OF OIL, GAS OR OIL AND GAS FROM ANY WELL LOCATED WITHIN BOUNDARIES OF A THREE-DIMENSIONAL SEISMIC SHOOT

165:10-21-82. General

Exemption from the levy of gross production tax on the production of oil, gas or oil and gas from a well, drilling of which is commenced on or after July 1, 2000, and prior to July 1, 2015, located within the boundaries of a three-dimensional seismic shoot and drilled based on three-dimensional seismic technology, shall be determined according to the provisions of this Part.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200400006, eff 7-1-04; Amended at 24 Ok Reg 1813 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001)]

165:10-21-82.1. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Three-dimensional seismic shoot" means any three-dimensional geophysical or seismic exploration activity conducted in the field for the purpose of drilling for and producing oil, gas or oil and gas from geological formations, intervals and/or common sources of supply.

"Three-dimensional seismic technology" means any three-dimensional geophysical or seismic equipment or instruments, data processing equipment, and/or data utilized to evaluate geological formations, intervals and/or common sources of supply in connection with a three-dimensional seismic shoot.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01]

165:10-21-82.2. Qualification procedure

(a) **Applicable wells.** The provisions of this Section establish criteria for determining if an operator producing oil, gas or oil and gas from a well, drilling of which is commenced on or after July 1, 2000, and prior to July 1, 2015, located within the boundaries of a three-dimensional seismic shoot and drilled based on three-dimensional seismic technology, has met the required conditions to qualify the production from such a well for the exemption from the Gross Production Tax. [See: 68 O.S. §1001(J)]

(b) **Administrative approval and determination.** An operator seeking an exemption of the gross production tax on production from a well located within the boundaries of a three-dimensional seismic shoot and drilled based on such

technology, shall make application to the Oklahoma Corporation Commission on a Form 1534 for a determination that the well qualifies for such exemption, as provided in 68 O.S. 2000 Supp. §1001(J).

(1)OCC Form 1534 shall be completed in its entirety, and together with supporting documentation, shall be submitted to the Technical Services Department of the Conservation Division of the Oklahoma Corporation Commission. If the application is administratively approved, a copy shall be available to the operator. If the application is denied or refused, or approval is delayed beyond sixty (60) days, the operator may seek review by application, notice and hearing.

(2) To obtain the tax exemption, the operator shall forward a copy of the approved application to the Oklahoma Tax Commission, together with any other data required by that agency pursuant to OAC 165:10-21-82.3.

(3) Any data, maps and other information submitted with the Form 1534 for determination that a well qualifies for the exemption provided in this paragraph shall be held as confidential information by the Conservation Division and/or Commission, and shall be returned to the applicant or destroyed upon approval of the application.

[SOURCE: Added in Rule Making 200000009, eff 5-11-2001; Amended in Rule Making 200300001, eff 7-1-2003; Amended in Rule Making 200400006, eff 7-1-2004; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 24 Ok Reg 1813 (RM 200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff. 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001)]

165:10-21-82.3. Rebates - Refund procedure

(a) **Request to Oklahoma Tax Commission for a tax refund.** If the Commission approves the application, the well operator or one of the working interest owners in the well, on behalf of the well operator and the other owners of the well, shall make its request for refund by letter to the Audit Division, Oklahoma Tax Commission. Such letter request shall state the reason for refund and the amount claimed and must be accompanied by the following:

(1) A copy of the application approved by the Corporation Commission certifying that the well meets the criteria of the statute insofar that its drilling was commenced on or after July 1, 2000, and prior to July 1, 2015, that it is located within the boundaries of a three-dimensional seismic shoot and was drilled based on such technology, and indicating whether the seismic shoot was shot either prior to or on or after July 1, 2000.

(2) A schedule of production, by month, of the gross amounts of oil, gas or oil and gas produced, and the gross values thereof, from the date of first sale until the date application is made to the Tax Commission.

(3) OTC Form 320A, 320C, and 320U, as are necessary, to set up the OTC Production Units, to request merge numbers, and to show the entity who will remit taxes.

(4) If the refund request is filed by any person other than the party named in the application, a notarized affidavit, signed by the party named in the application must be filed, authorizing the applicant to apply for the refund.

(b) **No rebate for production occurring prior to July 1, 2003; claim limitation.** Effective July 1, 2014, no refund of gross production taxes shall be claimed for oil and gas production exempt from gross production taxes pursuant to 68 O.S. Section 1001(J) for production occurring prior to July 1, 2003. Claims for rebate filed with the Oklahoma Tax Commission shall be subject to limitations pursuant to Title 68 O.S., Sections 1001(L) and 1001(M).

(c) **Method of appeal.** If the refund is denied, the applicant may file an appeal under the provisions of Title 68, Sections 227 and 228 of the Oklahoma Statutes.

[**SOURCE:** Added in Rule Making 200000009, eff 5-11-2001; Amended in Rule Making 200300001, eff 7-1-2003; Amended in Rule Making 200400006, eff 7-1-2004; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 24 Ok Reg 1813 (RM

200700004), eff 7-1-2007; Amended at 27 OK Reg 2128, eff 7-11-10 (RM 201000003); Amended at 29 OK Reg 950, eff 7-1-12 (RM 201200005); Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001); Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

165:10-21-82.4. Time periods for exemption from gross production tax levied on oil, gas or oil and gas production from a well located within boundaries of three-dimensional seismic shoot

The exemption from gross production tax levied on oil, gas or oil and gas production from a well qualified pursuant to this Section shall be applied as follows:

(1) **Eighteen (18) month exemption.** For a well where the seismic shoot was shot prior to July 1, 2000, the well shall be exempt from the gross production tax levied from the date of first sales for a period of eighteen (18) months.

(2) **Twenty-eight (28) month exemption.** For a well where the seismic shoot was shot on or after July 1, 2000, the well shall be exempt from the gross production tax levied from the date of first sales for a period of twenty-eight (28) months; provided, however, that the exemption shall not apply to production occurring on or after July 1, 2017.

[SOURCE: Added in Rule Making 200000009, eff 5-11-01; Amended in Rule Making 200300001, eff 7-1-03; Amended at 35 Ok Reg 973, eff. 9-14-18 (RM 201800002)]

PART 15. GENERAL PROVISIONS

165:10-21-85. Election of exemption

(a) **Election of exemptions generally.** Persons entitled to exemption based upon production from qualifying oil, gas, or oil and gas wells shall be entitled only to the exemption granted pursuant to:

(1) Incremental production from enhanced recovery projects, as authorized by 68 O.S. §1001(D) and Part 13 of this Subchapter; **or,**

(2) Horizontally drilled production wells, as authorized by 68 O.S. §1001(E) and Part 11 of this Subchapter; **or,**

(3) Reestablished production from inactive wells, as authorized by 68 O.S. §1001(F) and Part 7 of this Subchapter; **or,**

(4) Production enhancement projects, as authorized by 68 O.S. §1001(G) and Part 6 of this Subchapter; **or,**

(5) Production from deep wells, as authorized by 68 O.S. §1001(H) and Part 8 of this Subchapter; **or,**

(6) Production from new discovery wells, as authorized by 68 O.S. §1001(I) and Part 9 of this Subchapter; **or,**

(7) Production from wells located within the boundaries of three-dimensional seismic shoot, as authorized by 68 O.S. §1001(J) and Part 14 of this Subchapter.

(b) **Special provision.** Prior to July 1, 2015, expiration of an exemption available for production from a qualifying well pursuant to one of Subsections (a)(2) through (a)(7) of this Section does not prohibit any person from qualifying for the exemption provided for in Subsection (a)(1). On or after July 1, 2015, expiration of an exemption available for production from a qualifying well pursuant to Subsections (a)(3) or (a)(4) of this Section does not prohibit any person from qualifying for the exemption provided for in Subsection (a)(1). An exemption granted pursuant to Subsection (a)(1) of this Section shall not apply to any production upon which a tax is paid at a rate of two percent. [See: 68 O.S.§1001(O)].

(c) **Refund limited to interest owners of record and operators at time of qualifying act.** Only the operator and interest owners of record at the time of the qualifying act are eligible for the rebate of gross production tax attributable to their interest in the project.

(1) In the case of a change in the operator of a qualified project, it is permissible for the new operator to file the claim for refund on behalf of all participating interest owners for the prior and the current periods, although the new operator would not be eligible for any share in the refund.
(2) A former operator or interest owner may also file the claim for the periods in which the owner or operator actively participated in the project and distribute the appropriate refund amounts to the eligible interest owners.

[**SOURCE:** Added at 13 Ok Reg 2933, eff 7-11-96; Amended in Rule Making 200000009, eff 5-11-2001; Amended in Rule Making 200600012, eff 7-1-2006; Amended at 32 Ok Reg 767, eff 8-27-15 (RM 201500001)]

PART 17. SALES TAX EXEMPTION FOR ELECTRICITY AND ASSOCIATED DELIVERY AND TRANSMISSION SERVICES SOLD FOR OPERATION OF RESERVOIR DEWATERING PROJECT AND/OR UNIT

165:10-21-90. General

(a) **Scope.** This Part deals with the classification by the Oklahoma Corporation Commission (Corporation Commission or Commission) of a reservoir dewatering project and/or unit for the purpose of an exemption, beginning January 1, 2004, from sales taxes levied on electricity and associated delivery and transmission services sold to an oil and gas operator for reservoir dewatering projects and associated operations commencing on or after July 1, 2003, as provided in 68 O.S. 2002 Supp., §1357(28).

(b) **Distinction from designation as reservoir dewatering oil spacing unit or other spacing application.** The classification of an area and reservoir(s) as a "reservoir dewatering project" and/or a "reservoir dewatering unit" pursuant to this Part shall be separate and distinct from the designation of a reservoir dewatering oil spacing unit for oil allowable purposes pursuant to OAC 165:10-15-18. Corporation Commission approval of an area and reservoir(s) for the instant sales tax exemption shall be made by application under this Part and not as a result of a spacing application filed for oil allowable purposes under OAC 165:10-15-1 and OAC 165:10-15-18, a spacing application filed for gas allowable purposes under OAC 165:10-17-2 through 10-17-16, a spacing application filed for horizontal drilling purposes under OAC 165:10-3-28, or any spacing application filed under OAC 165:10-1-22.

(c) **Reservoir Dewatering Projects for Oil Production.** Any reservoir that is the subject of an application pursuant to this Part, which produces predominantly oil, shall be evaluated to determine the initial water-to-oil ratio is equal to or greater than five-to-one (5-to-1).

(d) **Reservoir Dewatering Projects for Gas Production.** Any reservoir that is the subject of an application pursuant to this Part, which produces predominantly gas, shall be evaluated to determine the initial five-to-one (5-to-1) water-to-oil ratio using a gas conversion factor of one (1) barrel of oil converted to an MCF of natural gas based on an initial natural gas formation volume factor, BTU or price calculation or conversion accepted by the Conservation Division.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

165:10-21-91. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Reservoir dewatering project" means an oil or gas production project covering a specified area and reservoir(s), which utilizes water recovery and disposal technology to increase water production in the initial phase of reservoir development, with the primary purpose of increasing oil or gas production from the reservoir(s) as a result of the dewatering process. For the purpose of qualification for the sales tax exemption pursuant to this Part, the definition of reservoir dewatering project shall require the proof that the

reservoir's initial water-to-oil ratio is greater than or equal to five-to-one (5-to-1), or is greater than or equal to the appropriate gas-to-water ratio calculated using the gas conversion factor outlined in OAC 165:10-21-90(d). This definition shall not include enhanced recovery projects or secondary recovery properties, which are subject to gross production tax exemptions pursuant to 68 O.S. Section 1001 and Part 13 of this Subchapter, OAC 165:10-21-75 through 10-21-80.

"Reservoir dewatering unit" means an area and reservoir(s) designated a reservoir dewatering project where a reservoir dewatering process is conducted as defined in this Part.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03]

165:10-21-92. Qualification procedure

(a) **Applicable operations.** The provisions of this Section establish criteria for determining if an area and reservoir(s) can be classified a reservoir dewatering project and/or a reservoir dewatering unit, beginning January 1, 2004, for the purpose of an exemption from sales taxes levied on electricity and associated delivery and transmission services sold to an oil and gas operator for a reservoir dewatering project and associated operations commencing on or after July 1, 2003.

(b) **Application to the Oklahoma Corporation Commission.** An oil and gas operator seeking the classification of an area and reservoir(s) as a reservoir dewatering project and/or reservoir dewatering unit pursuant to this Part shall file an application with the Corporation Commission on a Form 1535 for a determination that the project and/or unit qualifies for the exemption, as provided in 68 O.S. 2002 Supp., §1357(28). The operator shall attach to the Form 1535 a copy of the following information:

(1) A production test or other appropriate data showing the initial water-to-oil ratio is greater than or equal to five-to-one (5-to-1) or is greater than or equal to the appropriate gas-to-water ratio calculated using the gas conversion factor outlined in OAC 165:10-21-90(d). For this purpose, a Corporation Commission Form 1013 may be filed with the sales tax exemption application to demonstrate the initial 5-to-1 water-to-oil ratio for the reservoir.

(2) Geological structure and isopach maps for the applicable reservoir showing its geological characteristics; and any additional engineering and geological data or information deemed necessary by the Conservation Division to evaluate the application.

(3) A schematic diagram of the electrical grid and dewatering and water disposal equipment associated with the reservoir dewatering project covered by the application.

(c) **Administrative approval and determination.**

(1) If the application is administratively approved, copy shall be forwarded to the operator.

(2) To obtain the tax exemption, the operator should contact the Director's Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, Ok. 73194.

(3) Any data, maps and other information submitted with the Form 1535 for determination that an area and reservoir qualify for the exemption provided in this Part shall be held as confidential information by the Conservation Division and/or Corporation Commission, and shall be returned to the applicant or destroyed upon approval of the application.

[**SOURCE:** Added in Rule Making 200300001, eff 7-1-03; Amended in Rule Making 200600012, eff 7-1-2006]

PART 19. STATE SALES TAX EXEMPTION FOR ELECTRICITY SOLD FOR OPERATION OF ENHANCED RECOVERY METHODS ON A SPACING UNIT OR LEASE

165:10-21-95. General

(a) **Scope.** This Part deals with the designation by the Oklahoma Corporation Commission (Corporation Commission or Commission) of enhanced recovery methods on a spacing unit or lease for the purpose of an exemption, beginning July 1, 2006, from sales taxes levied on electricity sold to an oil and gas operator for such operations, as provided in 68 O.S. §1357(32).

(b) **Distinction from designation as enhanced recovery project pursuant to application for underground injection, spacing or unitization.** The designation of enhanced recovery methods on a spacing unit or lease pursuant to this Part shall be separate and distinct from the designation of an enhanced recovery project otherwise provided by Commission rules. The Commission's designation pertaining to the instant sales tax exemption shall be made by application under this Part and not as a result of an application for: (1) enhanced recovery project designation under OAC 165:10-5-4; (2) drilling and spacing units under OAC 165:10-15-1 and OAC 165:10-15-18 (oil allowables), OAC 165:10-17-2 through 10-17-16 (gas allowables), OAC 165:10-3-28 (horizontal drilling), or any spacing application under OAC 165:10-1-22; or (3) unitization under Title 52 O.S., § 287.1 et seq. and OAC 165:5-7-20.

[**SOURCE:** Added in Rule Making 200600012, eff 7-1-2006]

165:10-21-96. Definitions

The following words and terms, when used in this Part, shall have the following meaning, unless the context clearly indicates otherwise:

"Enhanced recovery methods" means production methods by which oil is produced, or is attempted to be produced, including but not limited to, increased pressure in a producing formation through use of water or saltwater if the electrical usage is associated with and necessary to the operation of equipment required to inject or circulate fluids in the producing formation for the purpose of forcing oil or petroleum into a wellbore for eventual recovery and production from the wellhead.

[**SOURCE:** Added in Rule Making 200600012, eff 7-1-2006]

165:10-21-97. Qualification procedure

(a) **Applicable operations.** The provisions of this Section establish criteria for designating enhanced recovery methods on a spacing unit or lease, beginning July 1, 2006, for the purpose of an exemption from sales taxes levied on electricity sold to an oil and gas operator for such operations.

(b) **Application to the Oklahoma Corporation Commission.** An operator seeking the designation of enhanced recovery methods on a spacing unit or lease pursuant to this Part shall file an application with the Corporation Commission on a Form 1535 for a determination that the operations qualify for the exemption, as provided in 68 O.S. §1357(32). The operator shall attach to the Form 1535 a copy of the following information:

(1) Production test or other appropriate data showing the total content of oil recovered after the use of enhanced recovery methods does not exceed one percent (1%) by volume. For this purpose, a Corporation Commission Form 1535 may be filed with the sales tax exemption application to demonstrate the daily rate and total content of oil recovery by volume from the spacing unit or lease prior to use of enhance recovery methods.

(2) Geological structure and isopach maps for the producing formation and any additional engineering and geological data or information deemed necessary by the Conservation Division to evaluate the application.

(3) A map and schematic diagram of the producing wells, underground injection or disposal wells, and other water injection or circulating equipment associated with the enhanced recovery methods on a spacing unit or leased covered by the application.

(c) **Administrative approval and determination.**

(1) If the application is administratively approved, a copy shall be forwarded to the operator.
(2) To obtain the tax exemption, the operator should contact the Director's Office, Taxpayer Assistance Division, Oklahoma Tax Commission, 2501 N. Lincoln Blvd., Oklahoma City, OK. 73194.
(3) Any data, maps and other information submitted with the Form 1535 for designation that enhanced recovery methods on a spacing unit or lease qualify for the exemption provided in this Part shall be held as confidential information by the Conservation Division and Corporation Commission, and upon approval of the application, shall be returned to the applicant or destroyed.

[**SOURCE:** Added at 23 Ok Reg, eff 7-1-06 (RM 200600012); Amended at 25 OK Reg 2187, eff 7-11-08 (RM 200800003)]

SUBCHAPTER 23. RATABLE SHARING OF REVENUE [REVOKED]

165:10-23-1. Definitions (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-2. General provisions for all interest owners in a well producing natural gas or casinghead gas (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-3. Revenue sharing in contract entered into on or after January 1, 1984; market by operator (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-4. Revenue sharing in contract entered into prior to May 3, 1983 (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-5. Revenue sharing in contract entered into on or after May 3, 1983, but prior to January 1, 1984 (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-6. Gas statements of production (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-7. Expiration of a gas contract (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-8. Special circumstances; parties selling under a joint operating agreement (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-9. Payments on production (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-10. Administrative expense (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-11. Commencement of an action (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-12. Other rights and remedies (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165-10-23-13. Crude oil (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-14. Liability (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

165:10-23-15. Severability (Revoked)

[**Source:** Revoked at 10 Ok Reg 2601, eff 6-25-93]

SUBCHAPTER 24. MARKET SHARING

[**Authority:** 52 O.S. 1992, Section 581.1 et seq.]

[**Source:** Codified 6-25-93]

165:10-24-1. Scope

(a) This Subchapter implements the Natural Gas Market Sharing Act of 1992, codified at 52 O.S. Section 581, et seq.

(b) This Subchapter establishes a procedure whereby an owner in a well may compel the well operator or other designated marketer to either sell gas on the owner's behalf or find a market for that owner's gas.

(c) This Subchapter shall apply to the sale of natural gas from a well except for:

(1) any sale under a gas contract for more than one year, entered into before January 1, 1985 (including any successor, replacement or roll-over contract entered into before January 1, 1990) provided that any participating mineral owners who were sharing in a contract on January 1, 1992, and continue to share in such a contract on September 1, 1992, are subject to this Subchapter;

(2) any sale under a contract which provides for:

(A) an initial term of more than three years; and

(B) a guarantee or warranty of delivery of fixed volumes without limitation on specified wells or reserves; and

(C) delivery of such volumes;

(3) any sale of natural gas liquids extracted by mechanical processing of the natural gas stream for removal of liquid components other than methane.

(d) Nothing in this Subchapter shall change the obligation of a first purchaser of production under an existing gas contract unless otherwise agreed to by the parties.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-24-2. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Designated marketer" means the operator of the well or a producing owner substituted for the operator as provided in 165:10-24-5.

"Electing owner" means any owner who elects to produce and market its share of production pursuant to the provisions of this Subchapter.

"Nonexempt sales" means those gas sales which are subject to the provisions of this Subchapter and do not qualify for exemptions as set forth in 165:10-24-1(c) and 165:10-24-3(b).

"Overproduced owner" means an owner who has produced and sold a volume of gas in excess of his working interest percentage of cumulative sales from a well.

"Owner" means a person or persons who own a working interest in a well.

"Producing owner" means an owner who produces and sells gas from a well for its own account.

"Working interest" means the interest in a well, calculated prior to deduction for royalty, overriding royalty and other non-cost bearing interests burdening production, entitling the owner thereof to drill for and produce oil and gas, including the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-3. Election to market share

(a) An owner eligible to market share as to a particular well, may elect to market share as to such well by sending written notice to the designated marketer for the well.

(b) An owner may not elect to market share as to a particular well if as to such well:

(1) said owner is subject to a balancing agreement (or other written agreement expressly providing for gas balancing or the taking, sharing, marketing of gas); or

(2) the term has yet to expire for a gas contract, where the owner terminated the contract for value received; or

(3) said owner terminated market sharing within the previous 12 months; or

(4) said owner is currently over-produced; or

(5) the designated marketer is relieved from the duty to market share pursuant to 165:10-24-4(g) or 165:10-24-4(i) and (j).

(c) An election to market share shall be effective on the first day of the month following 60 days from receipt of the election by the designated marketer.

(d) The well operator shall serve as the designated marketer until appointment of a substitute.

(e) An owner may terminate his election by sending writing notice to the designated marketer. Notice of termination is effective on the first day of the month following 60 days after receipt of the notice.

(f) Copies of all market sharing elections and notices shall be sent to the well operator, if said operator is not the designated marketer.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-4. Duties and accounting

(a) The designated marketer shall find an independent, non-affiliated purchaser for the electing owner's gas, or the designated marketer shall produce and sell said gas for the account of the electing owner.

(b) During market sharing, the designated marketer shall have the right to produce and sell and electing owner's gas, without further notice and consent except in those cases where the designated marketer has secured an independent non-affiliated purchaser for the gas production of such electing owner.

(c) If the designated marketer produces and sells the electing owner's gas for the account of the electing owner, the designated marketer shall account to the electing owner at the average price, weighted by volume, received by the marketer for all of the designated marketer's non-exempt sales from the well for that month, less post production cost and expenses required to render the gas marketable and to sell and deliver the gas to market, and net of all reasonable marketing costs, expenses and administrative fees. Volumetric allocation between the designated marketer and the electing owner shall be in proportion to their working interests in the well, with one exception. If the owner's proportionate production interest is different from his working interest, the proportionate production interest shall be used.

(d) Disbursement of gas sales proceeds shall be subject to the Production Revenue Standards Act of 1992 (52 O.S. Section 570.1, et seq.).

(e) The designated marketer shall not be considered as a fiduciary to any electing owner or to any owner with an interest burdening the electing owner's interest. The designated marketer shall not be liable for losses absent bad faith, gross negligence or willful misconduct.

(f) Market sharing according to this Subchapter shall not confer any contract rights to an electing owner or his assigns, either directly or as third party beneficiaries.

(g) For a gas contract with a term in excess of one year, the designated marketer may require an electing owner to either agree in writing to be bound by the contract terms or forego market sharing under that contract. Absent a confidentiality provision in said gas contract, the designated marketer shall send a copy of the gas contract to each electing owner.

(1) After receipt of the contract, the electing owner shall have 30 days in which to:

(A) send written consent to the contract terms, or

(B) provide a written termination of market sharing or

(C) elect a new designated marketer.

(2) If the electing owner fails to so respond, his election to market share shall be deemed terminated.

(h) If the designated marketer ceases to sell gas from the well and therefore has no sales, the designated marketer:

(1) may:

(A) notify the electing owners in writing that it has no sales and that the electing owners must elect a new designated marketer, or

(B) locate a non-affiliated purchaser for the electing owners.

(2) shall not be responsible for sharing sales with electing owners as it has no sales. If such a designated marketer again begins to produce and market gas from the well, then the electing owners may re-elect it as designated marketer.

(i) If the designated marketer provides the electing owner with a sales contract with a gas purchaser, the designated marketer shall be relieved of the duty to market share with the electing owner to the extent that the terms of said contract provide for the purchase of the electing owner's share of each withdrawal from the well during the contract period, provided:

(1) The designated marketer is not an affiliate of the gas purchaser: said term "affiliate" being defined at 18 O.S. Section 1148A(2); and

(2) The contract is of a type and with terms generally offered at the time to other producers for gas production from wells in the common source of supply; and

(3) If the designated marketer operates and controls a gathering line to the well, it does not prohibit access to downstream transportation or impose unjust or discriminatory gathering fees or tariffs upon the electing owner; and

(4) Before discontinuing market sharing if it had begun, the designated marketer provides the electing owner with at least thirty days in which to accept or reject the offer for said contract.

(j) In so far as the exemption established by subsection (i) of this Section, if the designated marketer fulfills each of the foregoing conditions, it shall be relieved from the duty to market share with the electing owner for a time period hereafter described as the "exemption period", calculated as follows:

(1) If the electing owner enters into said contract with said purchaser, then the exemption period shall be the duration of the contract as originally offered to the electing owner or the duration of the contract as entered into by the electing owner, whichever is greater;

(2) If the electing owner fails to enter into said contract for any reason, then the exemption period shall be the duration of the contract period as initially offered to the electing owner or twelve months, whichever is less.

(k) During the exemption period as determined in subsection (j) of this Section, failure to enter into said contract shall not be grounds for election or appointment of an additional designated marketer to market share with the electing owner with respect to volumes of gas which would have been purchased if the electing owner had entered into the said contract as initially offered to the electing owner.

(l) Upon request, the designated marketer or electing owner shall provide the first purchaser of production with information concerning the election to market share and the electing owner's share of monthly production.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-5. Replacement of the designated marketer

A new designated marketer may be appointed by a majority vote of the remaining market sharing owners. If an electing owner does not agree to the terms of a gas contract with a term greater than one year, the electing owner may elect a new designated marketer unless said election is prohibited by 165:10-24-4(i) and (j). Otherwise, substitution of the designated marketer shall occur not more than once every twelve months.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-24-6. Fees

(a) The designated marketer may charge each electing owner with an administrative fee for marketing the electing owner's share of production. Said fee shall be assessed monthly on a per-well basis. It shall be based on a formula described in this Section subject to annual adjustments as provided below. Said formula consists of 2.5% of the electing owner's monthly share of proceeds, but not less than twenty dollars nor more than seventy-five dollars, unless application of the annual adjustment factor provides a different maximum amount. The maximum amount of the fee permitted by this Section shall be adjusted as of the first day of May each year following May 1, 1993. The annual adjustment shall be computed by multiplying the rate currently in use by the percentage of increase or decrease in the annual overhead adjustment factor established by the Council of Petroleum Accountants Societies at its annual spring meeting for purposes of adjusting the combined fixed-rate overhead charges against joint operations in a well.

(b) If the designated marketer produces and sells gas for the account of the electing owner, the designated marketer may charge the electing owner or deduct said fee from the electing owner's share of the undistributed proceeds of production.

(c) Administrative fees under this Section shall be in addition to and separate from any and all post-production costs and expenses, including but not limited to reasonable marketing costs and expenses which may also be deducted from the proceeds payable to eligible electing owners.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

SUBCHAPTER 25. ESCROWED ACCOUNTS FOR POOLED MONIES

165:10-25-1. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise:

"Escrow account" means an account established in a financial institution and held in the name of the holder and an escrow agent wherein each owner is federally insured to One Hundred Thousand Dollars ($100,000.00).

"Financial institution" means a federally or state chartered bank, savings and loan, or credit union.

"Holder" means any person in possession of royalties, bonus payments, or other monies directed to be paid under a Commission pooling order and which cannot be paid because the persons entitled thereto are unknown or cannot be located.

"Owner" means the last known record titleholder of a mineral interest which is subject to a Commission pooling order.

"Person" means any individual, partnership, joint stock associations, trust, cooperative, unincorporated association, or corporation.

165:10-25-2. Escrow account required

(a) Each pooling order which pools interest of unknown or unlocated owners shall contain language substantially similar to the following: "If any payment of bonus, royalty payments, or other payments due and owing under this order cannot be made because the person entitled thereto cannot be located or is unknown, then said bonus, royalty payments or other payments shall be paid into an escrow account in a financial institution within ninety (90) days after this order and shall not be commingled with any funds of the applicant or operator. Provided however, that the Commission shall retain jurisdiction to grant to financially solid and stable holders an exception to the requirement that such funds be paid into an escrow account with a financial institution and permit such holder to escrow such funds within such holder's organization. Responsibility for filing reports with the Commission as required by law and Commission rule as to bonus, royalty or other payments escrowed hereunder shall be with the applicable holder. Such escrowed funds shall be held for the exclusive use of, and the sole benefit of, the person entitled thereto. It shall be the responsibility of the operator to notify all other holders of this provision and of the Commission rules regarding unclaimed monies under pooling orders".

(b) Each pooling order issuing upon an application filed on or after July 1, 1984, shall contain, in addition to the foregoing language, an attached exhibit listing all parties or interests which are unknown or cannot be located, together with each party's last known address, if available.

165:10-25-3. Escrow account requirements

(a) Monies which are directed to be paid under a Commission pooling order and which cannot be paid because the persons entitled thereto are unknown or cannot

be located shall be placed into escrow accounts in a financial institution. The holder shall choose the institution. The holder and the financial institution may make such arrangements as are necessary and appropriate for the establishment of the account. Service charges, fees, and costs may be deducted from any interest generated by the monies but in no event shall such charges, fees, and costs be deducted from the principal. Any financially solid and stable holder may apply to the Commission for an exception to the requirement to place monies into escrow accounts in a financial institution. The granting of an exception shall be within the sole discretion of the Commission and may only be granted upon the filing of a proper application therefor pursuant to notice given to the Manager of the Mineral Owners Escrow Account by mail at least ten days prior to the hearing and by publication one time at least 15 days prior to the hearing in a newspaper of general circulation in Oklahoma County and in a newspaper of general circulation in the county where the holder's principal office in the state is located. The granting of an exception shall not exempt the holder from any other requirements set forth in this Subchapter.

(b) Only one account need be established by each holder. If only one account is established, a record shall be make of deposits and withdrawals for each person for whom monies are being held. Either the holder or the financial institution may keep the deposit/withdrawal record.

(c) An application for an exception under (a) of this Section shall state that the holder has proof by the holder's annual financial statement that it is a solid and stable holder. The holder must introduce its annual financial statement into evidence in the cause and the order, if one is issued, shall show that the annual financial statement was in fact introduced into evidence and considered by the Administrative Law Judge in making the determination to grant holder's request for an exemption under (a) of this Section, and holder shall submit a current financial statement on an annual basis thereafter.

(d) Withdrawals from such escrow account by the holder may only be made for the following purposes:

(1) To pay the rightful recipient of the monies upon presentation of a proper claim.

(2) To submit and pay to the Commission the principal of all monies placed in escrow pursuant to 165:10-25-6.

(3) To correct an overpayment or other mistake made in the distribution of monies by the holder.

[**SOURCE:** Amended at 9 Ok Reg 2337, eff 6-25-92]

165:10-25-4. Payment to owner

The holder shall have a designated officer or employee to whom claims upon the escrow account may be made. The holder shall promptly pay the appropriate sum to any person showing the holder sufficient proof of ownership and proof of identity as may be determined in good faith by the holder. The holder shall report any payments made on his annual report to the Commission.

165:10-25-5. Reports to the Commission

Each holder shall submit a report for persons who cannot be located or are unknown and for whom monies are being held in escrow no later than 30 days after such holder's annual reporting date. Each holder's initial report shall be filed no later than one year and 30 days after the date of the issuance of the first pooling order subject to this Subchapter. Such reports shall be filed each year that any monies are held in escrow, until the well is plugged.

165:10-25-6. Payment to the Commission

(a) No later than 30 days after the annual reporting date of each year, the holder shall submit to the Commission the principal of all monies placed in escrow accruing under the orders issued during the first year, and all subsequent years where the sum exceeds $100.00 for any one person.

(b) If the holder has placed in escrow less than $100.00 for any one person, the holder may follow the procedures for deposit, or maintain the funds in escrow. If the amount accumulates to over $100.00 for any one person after any annual reporting date, it shall be submitted to the Commission on the next annual reporting date.
(c) Payments shall be tendered to the Finance Office of the Commission. Payments shall be made by cashier's check, certified check, or money order made payable to the "Oklahoma Corporation Commission".

165:10-25-7. Affidavit of compliance

In addition to the Plugging Record (Form 1003) and Completion Report (Form 1002A) required under 165:10-11-7, the operator shall file a compliance affidavit. No plugging bond shall be released until after the compliance affidavit is filed.

165:10-25-8. Forms

The Commission may issue appropriate forms to implement the provisions of this Subchapter.

165:10-25-9. Release from liability

Any holder who pays or delivers monies to the Commission required to be paid under this Subchapter shall be relieved of all liability for the monies so paid or delivered for any claim which then exists or thereafter may arise or be made in respect to such monies.

165:10-25-10. Construction

This Subchapter shall not be construed as limiting the Commission's authority to grant an exception to any rule in this Subchapter, unless precluded by law.

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SUBCHAPTER 27. PRODUCTION REVENUE STANDARDS

[**Authority:** 52 O.S. 1992, Section 570.13 et seq.]

[**Source:** Codified 6-25-93]

165:10-27-1. Scope

This Subchapter implements the Production Revenue Standards Act of 1992, codified at 52 O.S. Section 570.1, et seq. It shall apply to all producing wells as set forth in the Production Revenue Standards Act of 1992. However, Sections 165:10-27-4 through 165:10-27-10 shall not apply to any well which is a part of a compulsory enhanced recovery project, or where royalty remittance is otherwise regulated by written agreement among all owners in the well. This Subchapter is intended to supplement and clarify as needed the language in the statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-2. Effective date [Revoked]

[**Source:** Added at 10 OK Reg 2601, eff 6-25-93; Revoked at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-3. Definitions

The following words or terms, when used in this Subchapter, shall have the following meaning, unless the context clearly indicates otherwise.

"Owner" means a person or governmental entity with a legal interest in the mineral acreage under a well which entitles that person or entity to oil or gas production or the proceeds or revenues therefrom.

"Produce", "producing" and **"production"** mean the physical act of severance of oil and gas from a well by an owner and includes but is not limited to the sale or other disposition thereof.

"Producing owner" means an owner entitled to produce who during a given month produces oil or gas for its own account or the account of subsequently created interests as they burden its interest.

"Proportionate production interest" means that interest in production which a working interest owner is entitled to produce in order to adjust for shifting of royalty burdens among working interest owners under the royalty provisions of 52 O.S. Sections 570.1, et seq., and is equal to the quotient of:

(A) the sum of a working interest owner's net revenue interest plus the net revenue interests of any subsequently created interests as they burden such owner's working interest,

(B) divided by the remainder of one (1) less the royalty share.

"Proportionate royalty share" means the percentage of the royalty share owned by a royalty interest owner calculated by dividing such owner's royalty interest in a well by the royalty share.

"Royalty interest" means the entirety of the percentage interest in production or proceeds therefrom:

(A) reserved or granted by a mineral interest owner exclusive of any interest defined as a working interest or a subsequently created interest, or

(B) otherwise provided or ascribed to a mineral interest owner by statute, rule, order or operation of law.

"Royalty interest in a well" means an owner's royalty interest multiplied by the quotient of:

(A) the gross mineral acres under the well attributable to such interest, divided by

(B) the total mineral acres under the well.

"Royalty proceeds" means the share of proceeds or other revenue derived from or attributable to any production of oil and gas attributable to the royalty share, but shall not include payments of bonus, delay rentals, shut-in royalties or any additional royalty payable to the Commissioners of the Land Office or other governmental entity, pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the royalty portion of actual proceeds from the sale of oil or gas.

"Royalty share" means the percentage of the well equal to the sum of all royalty interests in the well.

"Share of production" means the monthly entitlement to produce belonging to a producing owner.

"Shipper" means any entity who contracts with a transporter to move gas through the transporter's system.

"Subsequently created interest" means any interest carved from a working interest other than a royalty interest. In addition to the royalty interest contained in a lease, a non-participatory interest created by a working interest owner for the benefit of a mineral interest owner in excess of a one-eighth (1/8) royalty interest may, by separate agreement other than the oil and gas lease, be a subsequently created interest and thereby not be communitized under the terms of the Production Revenue Standards Act only if there is clear and unambiguous language expressing that intent in the creating document. The additional royalty payable to the Commissioners of the Land Office or other governmental entity pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the sale of oil or gas, shall also be a subsequently created interest and thereby shall not be communitized under 52 O.S. Section 570.1, et seq.

"Well" means an oil or gas well, and shall include:

(A) a well having uniform ownership as to all producing zones, or

(B) a drilling and spacing unit having uniform ownership wherein multiple wells producing gas are commonly metered, and

(C) each separately metered producing zone within a single wellbore wherein ownership varies by zone.

"Working interest" means the interest in a well entitling the owner thereof to drill for an produce oil and gas, including but not limited to the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-4. Well operator records

Each well operator shall establish or cause to be established records showing the production allocations and payments to each interest owner in the well. For purposes of such records, the working interest owners shall provide the well operator with accounting and remittance information as required by statute. At a minimum, the required information shall consist of the name, address, interest amount and tax identification number of each royalty owner along with payment status. Each working interest owner shall provide said information in writing within 60 days of receipt of a written information request from the well operator. Updated information shall be provided by a working interest owner within 60 days after receipt of notice of a change.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-5. Pre-sale nominations

(a) Any producing owner marketing production separately from the well operator shall send pre-production nominations to the well operator for his withdrawals. A nomination shall be due five business days prior to the month in which the nomination is to be effective, but earlier if required by the first purchaser or transporter. The nomination shall consist of the name of the first purchaser or shipper, shipper contract number and the volumes of gas nominated for production for such producing owner's account.

(b) Nothing in this Section shall supersede or limit the operator's right to control gas nominations and allocations under a joint operating agreement, separate balancing agreement or Commission order.

(c) The owner of the gas meter shall confirm all nominations with the operator of the well no later than the last business day prior to the month in which production occurs.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-6. Entitlement

Each producing owner in a well shall be entitled to produce each month his proportionate production interest subject to balancing restrictions created by statute, rule, agreement or operation of law.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-7. Post-sale reports

(a) Within sixty days after the end of the month of production, each producing owner shall report and account to the operator of the well, the identity of the first purchaser or shipper of the gas and information specified in 165:10-27-13.

(b) Within fifteen days after the end of the month of production, each owner of a gas meter taking gas solely from a gathering system shall provide upon first request by the owner of such gathering system and thereafter, the gross volume of gas measured by such meter both in MCF and British Thermal Unit equivalent.

(c) Within twenty days after the end of the month of production, each owner of a gas meter shall provide or cause to be provided in writing to the operator of the well, the gross volume of gas measured by such meter, both in MCF and British Thermal Unit equivalent, and the volume of gas allocated at the meter to each first purchaser or shipper and each contracted producing owner that sold gas to the owner of the gas meter. Each meter owner shall, within the same time period, furnish each first purchaser or shipper the volume of gas allocated at the meter to that first purchaser or shipper. However, if the gas processing plant operator is performing the allocations, then within ten days after the end of the month of production, the owner of the pipeline residue gas meter shall provide, upon first request by the processing plant operator and thereafter, the volume in MCF and British Thermal Unit equivalent measured through its meter as

required by the gas processing plant operator for its allocations under this subsection.

(d) As an alternative to supplying the operator with information in the manner prescribed by subsections (b) and (c) of this Section, the owner of a gas meter who has a contract with one or more producing owners, covering all of the gas flowing through its meter, may furnish monthly volume statements to the operator of the well, provided said owner of the gas meter has previously furnished the operator with names of the producing owners and the decimal interest owned by each such producing owner or owners or any method other than by decimal interest then in effect for allocating gas among the producing owners. After adopting alternative reporting under this subsection, the owner of the gas meter shall be required to supply the operator of the well with any change to the name of a producing owner, the decimal interest by a producing owner or the method, other than by decimal interest, for allocating gas among the producing owners: such change to reported by the owner of the gas meter to the operator of the well within thirty days after the owner of the gas meter receives notice of such change.

(e) Within thirty-five days after the end of the month of production, each first purchaser or shipper of gas from a gas meter shall furnish or cause to be furnished to the operator of the well, a volume allocation statement showing the volume of gas purchased from or shipper for each contracted producing owner. Within thirty days after making any retroactive gas volume adjustment for such well, the first purchaser or shipper shall furnish notice of such retroactive gas volume adjustment to the operator of the well.

(f) Any person subject to multiple reporting requirements under this Section shall not be required to re-report the same information to the operator if such information has been previously provided by such person in a different report. Such person may consolidate the required information into a single report to the operator; provided, however, that all such reporting must comply with the applicable statutory time periods for the type of information being communicated to the operator.

(g) Any first purchaser, shipper or owner of a gas meter that does not provide the information required of it by this Section shall be subject to having its takes from the well suspended by the operator of the well pursuant to 165:10-27-8.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, 7-11-94]

165:10-27-8. Operator's option to confirm zero volume of gas sales because of noncompliance

(a) If a producing owner fails to timely provide the operator of the well with any of the information required by 165:10-27-4 and 165:10-27-7, or if the owner of a gas meter, first purchaser or shipper of gas fails to timely provide the operator of the well with any of the information required of it by 165:10-27-7 for the transfer, transportation, delivery or sale of gas by a producing owner, the operator of the well shall have the right, but not the obligation, to confirm zero volume of gas sales for such producing owner, and to make available for nomination and sale to other producing owners in the well, then in compliance with said Sections, all of such producing owner's share of production for the next subsequent calendar month and for each and every month thereafter of noncompliance. If the operator elects to make such producing owner's share of production available for nomination and sale, the operator shall immediately notify such producing owner by certified mail and inform such producing owner that such producing owner shall no longer have the right to nominate any volume of gas, until the next production month following the date of compliance, unless the operator of the well agrees to an earlier date. Such notice shall contain the lease or well identification, legal description, production months of noncompliance, a brief description of the noncompliance, and a provision stating that the operator is confirming zero volume of gas sales for such producing

owner. The operator shall than immediately notify each producing owner then in compliance with the aforesaid Sections and inform said producing owner about additional gas volumes available for nomination and sale. In regard to the producing owner for which the operator has confirmed zero gas sales, the operator shall also immediately notify in writing such producing owner's first purchaser or shipper, and the owner of the gas meter, and such notice shall report that such producing owner does not have the right to nominate and sell or transport any volume of gas, until the next production month following compliance, unless the operator of the well agrees to an earlier date. Such notice shall also contain the lease or well identification, legal description, a brief description of the noncompliance, and the production months of noncompliance.

(b) As soon as a noncomplying party is in compliance, but no sooner than the next production month unless otherwise agreed to, the operator of the well shall give the affected producing owner the opportunity to nominate and sell gas subject to existing agreements or by common practice within the oil and gas industry.

(c) The first purchaser or shipper and the owner of the gas meter shall be entitled to rely on and shall incorporate on a prospective basis any nomination or allocation changes pursuant to such notification from the operator under this Section. Changes pursuant to such notification may be made on a retroactive basis if so agreed to by the operator, owner of the meter, the first purchaser or shipper.

(d) The remedies provided for in this Section shall not preclude any party from pursuing the remedies available to it through the district courts, as provided by existing law, including the right of offset.

(e) All elections and notices given pursuant to the provisions of this Subchapter shall become effective as of the first day of the month following the end of any time period specified in the Production Revenue Standards Act as last amended, 52 O.S. Section 570.1, et seq.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93; Amended at 11 Ok Reg 3699, eff 7-11-94]

165:10-27-9. Designated payor for royalty distributions

(a) For royalty distributions, the well operator shall serve as payor for all proceeds of production, absent appointment of a substitute payor and/or election of a working interest owner to distribute royalties attributable to that working interest owner's sales.

(b) A substitute payor may be appointed by Commission order or by the owners owning a majority in interest of the working interest in the well. A substitute payor so appointed shall assume the rights and duties of the well operator concerning assessment of fees, royalty record maintenance and disbursement of royalties. A surety bond of $50,000 shall be required if the substitute payor is not a working interest owner, a first purchaser of production from the well, a bank or a trust company. Such bond shall be posted with the Surety Department of the Conservation Division before receipt of sales proceeds by the substitute payor. Any such bond shall be drafted so as to compensate royalty owners if the substitute payor defaults on his disbursement obligation.

(c) A producing owner may elect to distribute royalties from his sales subject to the following conditions:

(1) the producing owner shall provide 60 days written notice to the operator before starting or stopping the alternative procedure;

(2) the producing owner shall assume liability for its errors;

(3) the producing owner shall report payment information to the well operator within 30 days after each disbursement;

(4) the producing owner cannot re-start the alternative procedure within 12 months after terminating it.

(d) For good cause shown, the Commission may cancel a producing owner's election to separately distribute royalty. Cancellation shall occur only by order after application, notice and hearing.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-10. Administrative fees

(a) This Section prescribes fees which may be charged by the operator of a gas producing well or substitute payor, for administrative expenses generated by the Production Revenue Standards Act.

(b) Fees shall be assessed on a per-well basis against the cost-bearing working interests in a well according to respective gross working interest. They shall not be assessed against either royalty interests or non-cost bearing working interests in the well.

(c) A one-time implementation fee shall cover any cost associated with establishing or modifying the well operator's record keeping for the well, and it shall apply to any existing gas producing well with a date of first production occurring before September 1, 1992. If operations are transferred to a different operator after assessment of the one-time implementation fee, the successor operator may not assess another implementation fee against the working interests in the well.

(d) Should any working interest owner in a well producing gas fail to fully and timely comply with the requirements of 165:10-27-4, the well operator or substitute payor shall have the right to charge against said non-complying working interest owner a late fee of two hundred-fifty dollars per affected well.

(e) An annual maintenance fee shall cover any cost associated with record keeping, issuance of gas balancing statements and any election of a producing owner regarding separate distribution of royalty proceeds. Maintenance fees shall be calculated on an annual basis using the first day of May as the anniversary date. Such fees may be prorated and billed on a monthly basis at the well operator's discretion. If a well has a date of first production after the first day of May of the calendar year, the annual maintenance fee shall be prorated based on the remaining number of months before the next anniversary date on the first day of May.

(f) No working interest owner other than the well operator shall be entitled to assess either an implementation fee or a maintenance fee.

(g) The rates for implementation fees and annual maintenance fees shall be based on the appropriate table values found in Appendix G to this Chapter, subject to annual adjustments as provided below. The appropriate table value shall be determined from a matrix using the number of working interest owners or royalty owners in a well. The table value shall be adjusted as of the first day of May each year following May 1, 1993. The annual adjustment shall be computed by multiplying the rate currently in use by the percentage of increase or decrease in the annual overhead adjustment factor established by the Council of Petroleum Accountants Societies at its annual spring meeting for purposes of adjusting the combined fixed-rate overhead charges against joint operations in a well.

(h) Any fee assessed under this Section may be billed or deducted from the working interest owner's share of undistributed proceeds of production.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-11. Balancing of royalty accounts

(a) In the event of a production imbalance among royalty owners in a well, the affected working interest owners may adopt a royalty payment method to balance the royalty accounts, provided it is used only to extent necessary to balance the cumulative accounts of the royalty owners, and prior notice of the plan is sent to the affected royalty owners and to the well operator along with any ongoing information necessary for said operator to discharge its duties.

(b) Nothing in this Section shall impair any balancing rights arising by contract or law.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-12. Record keeping

Any record required by this Subchapter shall be maintained for a period of at least five years. Upon reasonable request, the well operator or substitute payor shall make available to a royalty owner for confidential inspection a record of receipts and payment of proceeds to said royalty owner, as well as copies of information furnished to the well operator pursuant to the Production Revenue Standards Act.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

165:10-27-13. Check stub information

(a) With each royalty payment, the following information shall be provided:

(1) lease or well identification;

(2) month and year of sales included in the payment;

(3) total barrels or MCF attributed to such payment;

(4) price per barrel or MCF, including British Thermal Unit adjustment of gas sold;

(5) gross production and severance taxes attributable to said interest;

(6) net value of total sales attributed to such payment after deduction of gross production and severance taxes;

(7) owner's interest in the well expressed as a decimal;

(8) owner's share of the total value of sales attributed to such payment before any deductions;

(9) owner's share of the sales value attributed to such payment less owner's share of the production and severance taxes.

(b) Upon payee's request, the payor shall provide a list of any other deduction from such payment.

(c) All revenue decimals shall be calculated to at least six decimal places.

(d) Gas volumes shall be measured according to 52 O.S. Section 474.

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

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SUBCHAPTER 29. SPECIAL AREA RULES

165:10-29-1. Lake Atoka and McGee Creek Reservoir

(a) **Scope.** The requirements of this section will apply to wells located in the areas listed below, and will supersede all field orders related to these areas. These requirements are in addition to the Commission's existing statewide requirements. The areas controlled by this section include:

(1) IN ATOKA COUNTY

(A) Sections 1-35 of Township 1 North, Range 12 East;
(B) Sections 1-18, 21-28 and 35-36 of Township 1 North, Range 13 East;
(C) Sections 1-36 of Township 1 North, Range 14 East;
(D) Section 6 of Township 1 North, Range 15 East;
(E) Sections 1-5, 8-16, 20-29 and 32-36 of Township 2 North, Range 12 East;
(F) Sections 1-36 of Township 2 North, Range 13 East;
(G) Sections 4-9 of Township 2 North, Range 14 East;
(H) Sections 1-2, 11-14, 23-26 and 36 of Township 1 South, Range 11 East;
(I) Sections 2-10, 16-20, 24-25 and 30-31 of Township 1 South, Range 12 East;
(J) Sections 1-3, 9-16, 19-30 and 32-36 of Township 1 South, range 13 East;
(K) Sections 1-11 and 13-36 of Township 1 South, Range 14 East;
(L) Sections 1-5, 8-17, 22-27 and 34-36 of Township 2 South, Range 13 East;
(M) Sections 1-24 and 26-35 of Township 2 South, Range 14 East;
(N) Sections 1-2 and 12 of Township 3 South, Range 13 East;
(O) Sections 2-9 of Township 3 South, Range 14 East.

(2) IN PITTSBURG COUNTY

(A) Sections 7, 18-22 and 25-36 of Township 2 North, Range 14 East;
(B) Section 31 of Township 2 North, Range 15 East;
(C) Sections 1-3, 9-16, 20-29 and 32-36 of Township 3 North, Range 12 East;
(D) Sections 1-36 of Township 3 North, Range 13 East;
(E) Sections 6 and 28-33 of Township 3 North, Range 14 East;
(F) Sections 26-28 and 32-36 of Township 4 North, Range 13 East.

(3) IN COAL COUNTY Sections 12-14, 22-27 and 34-36 of Township 1 North, Range 11 East.

(b) **General.** The design criteria for all wells shall consider all pertinent factors for well control including formation pressures and casing setting depths such that the wellbore can be maintained under control at all times and that all surface and subsurface fresh water supplies or formations are protected.

(c) **Well site limitations.** No oil and/or gas well shall be located within 1,320 feet of the maximum water surface level contour line of either reservoir. The maximum water surface level is 609.8 feet above sea level for McGee Creek and 590 feet above sea level for Lake Atoka Reservoir.

(d) **Drill site containment.** During the drilling and completion of an oil and gas well the operator shall:

(1) Maintain an earthen retaining wall downslope of the well, no closer than 50 feet from the wellbore, if the well is located within six (6) miles

of the maximum water surface level contour line of either reservoir. The maximum water surface level is 609.8 feet above sea level for McGee Creek Reservoir and 590 feet above sea level for Lake Atoka. The retaining wall shall be constructed prior to the commencement of drilling and shall be of adequate size for the terrain involved with a minimum length of 330 feet and a minimum compacted height of two (2) feet;

(2) Maintain a diversion ditch upslope of the well. The diversion ditch shall be constructed prior to the commencement of drilling and shall be adequate to divert surface drainage water from the well location;

(3) Pump any fluid, other than storm water, trapped within the well site into steel tanks for storage and removal. Storm water may be discharged as necessary as long as there is no sheen or other visible evidence of hydrocarbons being present, the chloride concentration does not exceed 500 mg/l, and the operator maintains records of each discharge for a period of three (3) years. These records must be supplied to the Commission upon request.

(e) **Production site containment.**

(1) During production operations, all fluid separation and storage vessels shall be enclosed within earthen or equivalent retaining walls so that the enclosed area has a storage capacity of at least one and one-half (1.5) times the liquid capacity of the largest vessel in the storage area.

(2) Any fluid other than storm water and any storm water that cannot be discharged will be pumped into steel tanks for storage and removal. Storm water may be discharged as necessary as long as there is no sheen or other visible evidence of hydrocarbons being present, the chloride concentration does not exceed 500 mg/l, and the operator maintains records of each discharge for a period of three (3) years. These records must be supplied to the Commission upon request.

(f) **Erosion control.** During the drilling phase of operations, silt fencing or other suitable materials or practices shall be used on the downslope side of the drill site to control runoff from the location. The silt fencing or other suitable materials or practices used to control runoff at the location shall be maintained in a manner so as to consistently work to control run-off.

(g) **Circulating and reserve pits.**

(1) Steel tanks shall be used for circulating and reserve pits for all drilling operations located within one (1) mile of the maximum water surface level contour line of either reservoir. The maximum water surface level is 609.8 feet above sea level for McGee Creek Reservoir and 590 feet above sea level for Lake Atoka.

(2) Outside of the areas designated by OAC 165:10-29-1(g)(1), any pit shall be lined with a geomembrane liner that meets or exceeds each of the following specifications:

(A) be made of linear low density polyethylene;

(B) have a thickness of 20 millimeters; and

(C) conform to the test requirements prescribed in the Geosynthetic Research Institute (GRI) Test Method GM17; and

(D) The liner shall also comply with the requirements for geomembrane liners found in OAC 165:10-7-16(c)(7).

(3) No pit shall be constructed or maintained so as to receive outside runoff water and the fluid level of earthen pits shall be maintained at all times as least 24 vertical inches below the lowest point of embankment.

(4) If there is flowback during the fracing of a well, the flowback must be to steel tanks prior to being placed into a lined pit if the temperature of the flowback exceeds 150 degrees Fahrenheit.

(5) The Oklahoma Corporation Commission shall inspect all pits within the purview of these rules prior to the liner being installed. The operator shall notify the District Office at least one (1) business day prior to installation of the liner. If the Commission has not inspected the pit within one (1) business day following the notification, the operator may proceed to install the liner.

(6) Any reserve/circulation pit shall be closed within six (6) months after drilling operations cease. Upon request by the operator, a six (6) month extension shall be granted by the District Office, after review by a field inspector to confirm the pit is in compliance with Commission requirements.

(h) **Air drilling.** When drilling with air for circulation, an unlined earthen pit to contain the wellbore cuttings is allowed, provided the chloride concentration of any fluids discharged into the pit does not exceed 1000 mg/l. Discharge of air and cuttings from the "blooey line" shall be subjected to fresh water injection or spray to eliminate, to the greatest extent possible, the drift of dust and particulates from the well site. Water and additives for liquid drilling fluid shall be maintained at the well site at all times in sufficient volumes to circulate the wellbore if needed. All water in the unlined earthen pit shall be removed and properly disposed of as soon as air drilling ceases.

(i) **Casing.** All casing shall be new or reconditioned and tested to conform to API specifications.

(1) **Surface casing.** Surface casing shall be set to a minimum depth of 700 feet, or 50 feet below the deepest treatable water, whichever depth is greater. In setting the surface casing, a minimum of six (6) centralizers shall be used in the bottom portion of the casing string.

(2) **Production casing.** Production casing of four and one-half (4.5) inches or greater OD, and all related equipment items, such as the wellhead valves, shall have a pressure rating sufficiently in excess of the highest formation pressure encountered in the well. In setting the production casing, the annular space between the wellbore and the production casing shall be filled with cement calculated to fill at least 500 feet above the shallowest planned zone to be tested. Centralizers shall be used across the planned zone(s) to be tested. The production casing shall be pressure tested to conform to OAC 165:10-3-4(g). In the event the total depth of the well is less than 500 feet, the annular space between the wellbore and the production casing shall be filled with cement calculated to fill at least that portion of the wellbore to the base of the surface casing. Centralizers shall be used across the planned zone to be tested. The production casing shall be pressure tested to comply with OAC 165:10-3-4(g).

(j) **Blowout prevention equipment.** Before drilling below the surface casing and until drilling operations are completed, a blowout preventer (BOP) with a minimum of two (2) hydraulically operated rams, one (1) blind type and one (1) pipe type to fit the drill pipe, and related well control equipment, including a manifold and a floor valve, with a working pressure that exceeds the maximum anticipated surface pressure, shall be installed, used and tested in a manner to prevent blowouts. The BOP stack shall include a drilling spool with side outlets if side outlets are not provided on the BOP body. BOPs shall be tested to the rated pressure of the blowout stack assembly. All blowout prevention equipment is to be tested prior to drilling out from the surface casing. While drilling operations are in progress, the BOP shall be actuated once each trip. When removing drill pipe from any hole that utilized drilling fluids, the annulus shall be filled with mud before the mud level drops 100 feet from surface. A Kelley-cock shall be installed below the swivel. Wells being drilled to a depth less than 4,000 feet may use annular type blowout preventers.

(k) **Drill stem testing.** Drill stem testing shall only be allowed during daylight hours. Fluid removed from the well during testing must be flowed or pumped into steel pits or tanks and promptly removed from the location at the conclusion of testing. The formation fluids in the hole shall be reversed-out prior to the removing of the drill stem test tool from the hole.

(l) **Prevention of leakage and pollution.** Equipment, pipe, pumps, tanks, and other appurtenances used in conducting operations shall be maintained at all times to prevent leakage and the escape of saltwater, oil and other deleterious substances. All oil, water and deleterious substances from wet strings of

tubing shall be drained into steel tanks. All cellars with oil and oil sumps shall be promptly pumped out.

(m) **Exceptions to this section.** When good cause is shown, and when it is not reasonably likely to result in any pollution to either reservoir, an administrative exception to a requirement of this section may be granted by the Oklahoma Corporation Commission. Notice of an application for an exception to this section shall be sent at least 15 days in advance to: (1) the manager of the District 4 Office of the Oil and Gas Conservation Division of the Oklahoma Corporation Commission; (2) the General Manager of the Oklahoma City Water Utilities Trust, 420 W. Main, Suite 500, Oklahoma City, Oklahoma 73102; and (3) the General Manager of the McGee Creek Authority, 420 W. Main, Suite 500, Oklahoma City, Oklahoma 73102. A 15-day period from the date of the written notice should be established for any party to file an objection to such an administrative application. If an objection is filed, a full hearing shall be held on the merits.

(n) **Other.** In reviewing an application for a permit-to-drill (form 1000), the Technical Services Department of the Oklahoma Corporation Commission will determine whether or not the well lies within any of the areas designated in OAC 165:10-29-1(c), OAC 165:10-29-1(d)(1) and OAC 165:10-29-1(g)(1).

[**SOURCE:** Added at 25 OK Reg 2187, eff 7-11-08 (RM 200800003)]

165:10-29-2. Alternative location requirements for horizontal well units

(a) **Scope and effect.** The well location requirements of this Section apply to horizontal wells completed in horizontal well units in designated common sources of supply as specified in this Section. Horizontal wells covered by this Section are subject to OAC 165:10-3-28 and other applicable Commission rules except as provided in this Section.

(b) **Woodford shale.**

(1) This subsection applies to horizontal wells completed in the Woodford shale common source of supply.

(2) The completion interval of a horizontal well subject to this subsection shall be located not less than the minimum distance from the boundary of a standard or non-standard horizontal well unit as follows:

(A) Not less than 330 feet from an east or west unit boundary.

(B) Not less than 165 feet from a north or south unit boundary.

[**Source:** Added at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Amended at 32 Ok Reg 767, eff. 8-27-15 (RM 201500001)]

165:10-29-3. Rush Springs Sandstone Groundwater Basin

(a) **Scope.** The requirements of this section will apply to the areas listed below, and will supersede Commission field order number 251978 related to these areas. These requirements are in addition to the Commission's existing statewide requirements. The areas controlled by this section include:

(1) IN BECKHAM COUNTY

(A) Sections 1-18, 21-25 and 36 of Township 8 North, Range 21 West;

(B) Sections 1-5, and 8-12 of Township 8 North, Range 22 West;

(C) Sections 19 and 26-36 of Township 9 North, Range 21 West;

(D) Sections 21-28 and 33-36 of Township 9 North, Range 22 West.

(2) IN BLAINE COUNTY

(A) Sections 2-11, 15-22 and 26-35 of Township 13 North, Range 12 West;

(B) All sections of Township 13 North, Range 13 West;

(C) Sections 2-35 of Township 14 North, Range 12 West;

(D) All sections of Township 14 North, Range 13 West;

(E) Sections 6-8, 16-21 and 27-35 of Township 15 North, Range 12 West;

(F) All sections of Township 15 North, Range 13 West;

(G) Sections 30 and 31 of Township 16 North, Range 12 West;

(H) Sections 3-11 and 13-36 of Township 16 North, Range 13 West;

(I) Sections 5-8, 16-21 and 28-34 of Township 17 North, Range 13 West;
(J) Sections 31 and 32 of Township 18 North, Range 13 West.

(3) IN CADDO COUNTY

(A) All sections of Township 5 North, Range 9 West;
(B) All sections of Township 5 North, Range 10 West;
(C) Sections 1-17, 20-29 and 33-36 of Township 5 North, Range 11 West;
(D) Sections 1, 2 and 12 of Township 5 North, Range 12 West;
(E) Sections 2-36 of Township 6 North, Range 9 West;
(F) All sections of Township 6 North, Range 10 West;
(G) All sections of Township 6 North, Range 11 West;
(H) Sections 1-5, 7-18, 21-27, 35 and 36 of Township 6 North, Range 12 West;
(I) Sections 12 and 13 of Township 6 North, Range 13 West;
(J) Sections 31-35 of Township 7 North, Range 9 West;
(K) Sections 4-10, 15-23 and 25-36 of Township 7 North, Range 10 West;
(L) All sections of Township 7 North, Range 11 West;
(M) Sections 1-30 and 32-36 of Township 7 North, Range 12 West;
(N) Sections 1-18 and 21-24 of Township 7 North, Range 13 West;
(O) Sections 6, 7, 17-20 and 28-33 of Township 8 North, Range 10 West;
(P) All sections of Township 8 North, Range 11 West;
(Q) All sections of Township 8 North, Range 12 West;
(R) All sections of Township 8 North, Range 13 West;
(S) Sections 3-11, 14-23 and 26-36 of Township 9 North, Range 11 West;
(T) All sections of Township 9 North, Range 12 West;
(U) All sections of Township 9 North, Range 13 West;
(V) Sections 6-9, 14-23, 26-30 and 32-34 of Township 10 North, Range 9 West;
(W) Sections 1-27 of Township 10 North, Range 10 West;
(X) Sections 1-8, 10-13, 17-20 and 28-33 of Township 10 North, Range 11 West;
(Y) All sections of Township 10 North, Range 12 West;
(Z) All sections of Township 10 North, Range 13 West;
(AA) All sections of Township 11 North, Range 11 West;
(BB) All sections of Township 11 North, Range 12 West;
(CC) All sections of Township 11 North, Range 13 West;
(DD) Sections 4, 5, 7-9 and 14-36 of Township 12 North, Range 11 West;
(EE) Sections 2-36 of Township 12 North, Range 12 West;
(FF) All sections of Township 12 North, Range 13 West.

(4) IN CANADIAN COUNTY

(A) Sections 16-21 and 28-30 of Township 11 North, Range 9 West;
(B) Sections 5-11 and 13-35 of Township 11 North, Range 10 West;
(C) Section 31 of Township 12 North, Range 10 West.

(5) IN COMANCHE COUNTY

(A) Sections 1-17, 21-27, 35 and 36 of Township 3 North, Range 9 West;
(B) Sections 1, 2 and 12 of Township 3 North, Range 10 West;
(C) All sections of Township 4 North, Range 9 West;
(D) Sections 1-29 and 33-36 of Township 4 North, Range 10 West;
(E) Sections 1-4 and 11-13 of Township 4 North, Range 11 West.

(6) IN CUSTER COUNTY

(A) All sections of Township 12 North, Range 14 West;
(B) All sections of Township 12 North, Range 15 West;
(C) All sections of Township 12 North, Range 16 West;
(D) Sections 1-28 and 34-36 of Township 12 North, Range 17 West;
(E) Sections 1-4 and 11-13 of Township 12 North, Range 18 West;
(F) All sections of Township 13 North, Range 14 West;
(G) All sections of Township 13 North, Range 15 West;
(H) All sections of Township 13 North, Range 16 West;
(I) All sections of Township 13 North, Range 17 West;
(J) Sections 1-30 and 32-36 of Township 13 North, Range 18 West;
(K) Sections 1-5, 9-15 and 24 of Township 13 North, Range 19 West;

(L) All sections of Township 14 North, Range 14 West;
(M) All sections of Township 14 North, Range 15 West;
(N) All sections of Township 14 North, Range 16 West;
(O) All sections of Township 14 North, Range 17 West;
(P) All sections of Township 14 North, Range 18 West;
(Q) All sections of Township 14 North, Range 19 West;
(R) Sections 1-3, 10-14 and 23-25 of Township 14 North, Range 20 West;
(S) All sections of Township 15 North, Range 14 West;
(T) All sections of Township 15 North, Range 15 West;
(U) All sections of Township 15 North, Range 16 West;
(V) All sections of Township 15 North, Range 17 West;
(W) All sections of Township 15 North, Range 18 West;
(X) All sections of Township 15 North, Range 19 West;
(Y) Sections 1-3, 10-15, 22-27 and 34-36 of Township 15 North, Range 20 West.

(7) IN DEWEY COUNTY

(A) All sections of Township 16 North, Range 14 West;
(B) All sections of Township 16 North, Range 15 West;
(C) All sections of Township 16 North, Range 16 West;
(D) All sections of Township 16 North, Range 17 West;
(E) All sections of Township 16 North, Range 18 West;
(F) All sections of Township 16 North, Range 19 West;
(G) Sections 1-3, 10-15, 22-27 and 34-36 of Township 16 North, Range 20 West;
(H) All sections of Township 17 North, Range 14 West;
(I) All sections of Township 17 North, Range 15 West;
(J) All sections of Township 17 North, Range 16 West;
(K) All sections of Township 17 North, Range 17 West;
(L) All sections of Township 17 North, Range 18 West;
(M) All sections of Township 17 North, Range 19 West;
(N) Sections 12-14, 23-26, 35 and 36 of Township 17 North, Range 20 West;
(O) Sections 31-36 of Township 18 North, Range 14 West;
(P) Sections 31-36 of Township 18 North, Range 15 West;
(Q) Sections 31-36 of Township 18 North, Range 16 West;
(R) Sections 31-36 of Township 18 North, Range 17 West;
(S) Sections 31-36 of Township 18 North, Range 18 West;
(T) Sections 31-36 of Township 18 North, Range 19 West.

(8) IN GRADY COUNTY

(A) Sections 19, 20 and 29-32 of Township 3 North, Range 6 West;
(B) All sections of Township 3 North, Range 7 West;
(C) All sections of Township 3 North, Range 8 West;
(D) Sections 4-36 of Township 4 North, Range 7 West;
(E) All sections of Township 4 North, Range 8 West;
(F) Sections 27-29 and 31-34 of Township 5 North, Range 7 West;
(G) Sections 2-11, 14-23 and 26-36 of Township 5 North, Range 8 West;
(H) Sections 7-11, 14-23 and 25-26 of Township 6 North, Range 8 West.

(9) IN KIOWA COUNTY

(A) Sections 1-6 and 9-14 of Township 7 North, Range 14 West;
(B) Sections 1-3 of Township 7 North, Range 15 West;
(C) All sections of Township 8 North, Range 14 West.

(10) IN STEPHENS COUNTY

(A) Sections 5 and 6 of Township 2 North, Range 6 West;
(B) Sections 1-12 of Township 2 North, Range 7 West;
(C) Sections 1-6 and 10-12 of Township 2 North, Range 8 West;
(D) Section 1 of Township 2 North, Range 9 West.

(11) IN WASHITA COUNTY

(A) Sections 1-6 of Township 7 North, Range 14 West;
(B) All sections of Township 8 North, Range 14 West;
(C) All sections of Township 8 North, Range 15 West;

(D) Sections 1-30, 35 and 36 of Township 8 North, Range 16 West;
(E) Sections 1-30 of Township 8 North, Range 17 West;
(F) Sections 1-26 of Township 8 North, Range 18 West;
(G) Sections 1-24, 30 and 31 of Township 8 North, Range 19 West;
(H) All sections of Township 8 North, Range 20 West;
(I) All sections of Township 9 North, Range 14 West;
(J) All sections of Township 9 North, Range 15 West;
(K) Sections 1-5, 8-17 and 20-36 of Township 9 North, Range 16 West;
(L) Sections 31-36 of Township 9 North, Range 17 West;
(M) Sections 31-36 of Township 9 North, Range 18 West;
(N) Sections 31-36 of Township 9 North, Range 19 West;
(O) Sections 31-36 of Township 9 North, Range 20 West;
(P) All sections of Township 10 North, Range 14 West;
(Q) All sections of Township 10 North, Range 15 West;
(R) Sections 1-5, 8-17, 20-29 and 32-36 of Township 10 North, Range 16 West;
(S) All sections of Township 11 North, Range 14 West;
(T) All sections of Township 11 North, Range 15 West;
(U) Sections 1-30 and 32-36 of Township 11 North, Range 16 West;
(V) Sections 1, 2 and 11-13 of Township 11 North, Range 17 West.

(b) **Commercial pits prohibited.** The construction, enlargement, reconstruction or operation of any commercial pit (as defined in OAC 165:10-9-1) in any area listed in subsection (a) above, is prohibited.

[**SOURCE:** Added at 29 OK Reg 950, eff 7-1-12 (RM 201200005)]

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APPENDIX A. ALLOCATED WELL ALLOWABLE TABLE* [REVOKED]

[**SOURCE:** Revoked at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

APPENDIX A. ALLOCATED WELL ALLOWABLE TABLE* [NEW]

DEPTH OF COMPLETION INTERVAL**	ACREAGE 10 or less	20	40	80	160
To-3000	30	45	57		
3001-3200	31	45	57		
3201-3400	32	46	58		
3401-3600	33	47	59		
3601-3800	34	48	60		
3801-4000	35	49	61		
4001-4200	36	49	61	71	
4201-4400	37	50	62	73	
4401-4600	38	51	63	75	
4601-4800	39	52	64	77	
4801-5000	40	53	65	79	
5001-5200	41	54	67	82	
5201-5400	42	55	69	85	
5401-5600	43	56	71	88	
5601-5800	45	58	73	91	
5801-6000	47	60	75	94	
6001-6200	49	62	77	97	
6201-6400	51	64	79	100	
6401-6600	53	66	82	103	
6601-6800	55	68	85	107	
6801-7000	57	70	88	110	
7001-7200	59	72	90	113	
7201-7400	61	74	92	116	
7401-7600	63	76	95	119	
7601-7800	65	78	98	122	
7801-8000	67	80	101	126	
8001-8200	69	83	104	130	
8201-8400	71	86	107	134	
8401-8600	73	89	111	139	

Appendix A, p2

DEPTH OF COMPLETION INTERVAL**	ACREAGE 10 or less	20	40	80	160
8601-8800	75	92	115	144	
8801-9000	77	95	119	149	
9001-9200	79	98	123	154	
9201-9400	81	101	127	159	
9401-9600	84	105	131	164	
9601-9800	87	109	136	170	
9801-10000	90	113	141	176	
10001-10200	95	119	148	185	333
10201-10400	100	125	156	195	351
10401-10600	105	131	164	205	369
10601-10800	110	137	172	215	387
10801-11000	115	144	180	225	405
11001-11200	122	153	190	239	431
11201-11400	129	162	202	254	458
11401-11600	137	171	214	269	485
11601-11800	145	181	226	284	512
11801-12000	153	191	239	299	539
12001-12200	163	203	254	318	573
12201-12400	173	215	269	338	609
12401-12600	183	228	285	358	645
12601-12800	193	241	301	378	681
12801-13000	203	254	317	398	717
13001-13200	213	266	333	416	749
13201-13400	223	278	349	436	785
13401-13600	233	290	365	455	819
13601-13800	243	303	380	475	855
13801-14000	253	316	395	494	890
14001-14200	263	328	410	514	926
14201-14400	273	340	426	534	962
14401-14600	283	353	441	554	998

Appendix A, p3

DEPTH OF COMPLETION INTERVAL**	ACREAGE 10 or less	20	40	80	160
14601-14800	293	366	457	573	1032
14801-15000	303	379	473	593	1068

***** Allowables currently are established at 200 percent of market demand. To determine the allowable for any well, the number in the appropriate column of the chart in the appendix must be doubled (multiplied by 2). The minimum allocated well is therefore 60 BOPD (from the 10 acre column, depth to 3,000 feet, 30 BOPD times 2) (Market Demand).

****** Depth in feet from the surface of the ground to the top of the completion interval.

[**SOURCE:** New at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

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APPENDIX B. DISCOVERY WELL ALLOWABLE TABLE [REVOKED]

[**SOURCE:** Revoked at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

APPENDIX B. DISCOVERY WELL ALLOWABLE TABLE [NEW]

(100 percent of market demand)

DEPTH OF COMPLETION INTERVAL*	BARRELS PER DAY	DAYS AFTER DISCOVERY
0-1000	100	365
1001-1200	105	391
1201-1400	110	416
1401-1600	115	442
1601-1800	120	467
1801-2000	125	493
2001-2200	130	518
2201-2400	135	545
2401-2600	140	569
2601-2800	145	596
2801-3000	150	621
3001-3200	155	647
3201-3400	160	672
3401-3600	165	698
3601-3800	170	723
3801-4000	175	749
4001-4200	180	774
4201-4400	185	800
4401-4600	190	825
4601-4800	195	851
4801-5000	200	876
5001-5200	205	910
5201-5400	210	942
5401-5600	215	975
5601-5800	225	1007
5801-6000	235	1041
6001-6200	245	1073
6201-6400	255	1107
6401-6600	265	1139
6601-6800	275	1172
6801-7000	285	1205
7001-7200	295	1245
7201-7400	305	1285
7401-7600	315	1326
7601-7800	325	1365

Appendix B, p2

DEPTH OF COMPLETION INTERVAL*	BARRELS PER DAY	DAYS AFTER DISCOVERY
7801-8000	335	1406
8001-8200	345	1445
8201-8400	355	1486
8401-8600	365	1526
8601-8800	375	1567
8801-9000	385	1606
9001-9200	395	1650
9201-9400	405	1694
9401-9600	420	1737
9601-9800	435	1781
9801-10000	450	1825
10001-10200	475	1837
10201-10400	500	1847
10401-10600	525	1859
10601-10800	550	1869
10801-11000	575	1880
11001-11200	610	1888
11201-11400	645	1895
11401-11600	685	1902
11601-11800	725	1910
11801-12000	765	1917
12001-12200	815	1917
12201-12400	865	1917
12401-12600	915	1917
12601-12800	965	1917
12801-13000	1015	1917
13001-13200	1065	1917
13201-13400	1115	1917
13401-13600	1165	1917
13601-13800	1215	1917

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DEPTH OF COMPLETION INTERVAL*	BARRELS PER DAY	DAYS AFTER DISCOVERY
13801-14000	1265	1917
14001-14200	1315	1917
14201-14400	1365	1917
14401-14600	1415	1917
14601-14800	1465	1917
14801-15000	1515	1917

***** Depth in feet from the surface of the ground to the top of the completion interval.

[**SOURCE:** New at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

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APPENDIX C: TABLE HD [REVOKED]

[**Source:** Revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); Revoked at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

APPENDIX C: TABLE HD [NEW]

RECOMMENDED ADDITIONAL ALLOWABLE FOR HORIZONTAL OIL WELLS
BASED ON TRUE VERTICAL DEPTH AND COMPLETION INTERVAL

AVERAGE TRUE VERTICAL DEPTH OF COMPLETION INTERVAL IN FEET	ADDITIONAL ALLOWABLE IN BARRELS PER FOOT OF COMPLETION INTERVAL
TO 4,000	.2
4,001 TO 8,000	.3
8,001 TO 12,000	.4
GREATER THAN 12,000	.5

All oil produced and marketed during the drilling and completion operations shall be charged against the allowable assigned to the well upon completion. Effective date of the allowable shall be the date of first production.

[**Source:** New at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); New at 28 OK Reg 1949, eff. 7-11-11 (RM 201000007)]

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APPENDIX D. LIST OF NGPA FORMS [REVOKED]

[SOURCE: Revoked at 13 Ok Reg 2401, eff 7-1-96]

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APPENDIX E. SCHEDULE A FINES [REVOKED]

[**Source:** Revoked in Rule Making 200200017, eff 7-1-02]

APPENDIX E. SCHEDULE A FINES [NEW]

RULE	VIOLATION	FINE
165:10-3-1	Failure to obtain permit (Form 1000) to drill, re-enter, deepen or recomplete.	$1,000
165:10-3-3	Failure to report surface casing failure.	$1,000
165:10-3-4	Failure to set sufficient surface casing or circulate cement.	$5,000
165:10-3-4	Failure to run and cement surface well marker.	$1,000
165:10-5-2	Failure to obtain permit for injection or disposal well.	$5,000
165:10-5-13	Failure to obtain permit for annular injection of drilling fluids.	$2,500
165:10-7-14	Failure to obtain approval to drill deep anode groundbed.	$1,000
165:10-7-16	Failure to obtain permit for construction of off-site pit.	$1,000
165:10-7-16	Illegal discharge from noncommercial pit.	$2,000
165:10-7-17	Failure to obtain permit to discharge produced water to surface.	$1,000
165:10-7-19	Failure to obtain permit for one-time land application of water-based fluids from tanks/ earthen pits.	$2,000
165:10-7-26	Failure to obtain permit for a one-time land application of contaminated soils or petroleum hydrocarbon-based drill cuttings.	$2,000
165:10-7-27	Failure to obtain permit to apply waste oil, waste oil residue, or crude oil contaminated soil to lease roads, pipeline service roads, tank farm roads, well locations and production sites.	$2,000
165:10-7-29	Failure to obtain permit for a one-time application of freshwater-based drill cuttings to private access areas, well locations and production sites.	$2,000
165:10-9-1	Failure to obtain permit for construction and use of commercial pit.	$5,000
165:10-9-1	Illegal discharge from a commercial pit.	$5,000

165:10-11-1	Failure to acquire license to pull pipe and plug wells.	$2,500
165:10-11-4	Failure to obtain plugging instructions and notify district office of time well is to be plugged.	$1,000

[**Source:** New in Rule Making 200200017, eff 7-1-02]

APPENDIX F. SCHEDULE B FINES [REVOKED]

[**Source:** Revoked in RM 200200017, eff. 7-1-02; revoked at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); and Revoked at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019)]

APPENDIX F. SCHEDULE B FINES [NEW]

RULE	VIOLATION	FINE
165:10-1-10	Failure to maintain current surety.	$500
165:10-3-4	Failure to protect treatable water or file for alternate casing procedure.	$2,500
165:10-3-17	Failure to remove trash, debris and junk from well site.	Up to $1,000
165:10-3-17	Failure to post lease sign or OTC number.	$50 per well/$500 per lease
165:10-3-25	Failure to file completion report, Form 1002A.	$250
165:10-3-26	Failure to submit required electric logs.	$250
165:10-3-35	Failure to obtain order for multiple completion.	$500
165:10-3-39	Failure to obtain order for commingling.	$500
165:10-5-6	Failure to conduct/perform mandatory initial mechanical integrity test within rule timeframe.	$500
165:10-5-6	Failure to perform subsequent mechanical integrity test.	$500
165:10-5-7	Failure to file fluid injection report, Form 1012 or Form 1012C.	$500
165:10-5-7	Failure to report loss of mechanical integrity on well.	$1,500
165:10-7-5	Failure to report non-permitted discharge.	$500
165:10-7-16	Failure to comply with any closure requirement for noncommercial pit.	$1,000
165:10-9-1	Failure to close commercial pit as required by rule.	$1,000
165:10-11-3	Failure to plug well in rule timeframe.	$1,000
165:10-11-7	Failure to file plugging report as required by rule.	$500

[**Source:** New in RM 200200017, eff. 7-1-02, New at 27 OK Reg 2128, eff. 7-11-10 (RM 201000003); and New at 34 Ok Reg 921, eff. 9-11-17 (RM 201600019)]

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APPENDIX G.

IMPLEMENTATION FEES (ONE - TIME)

No. of RIOs*	No. of Working Interest Owners 2-10	11-20	21+
2-30	$350	$500	$650
31-100	$500	$500	$650
100+	$650	$650	$650

MAINTENANCE FEES (ANNUAL)

No. of RIOs*	No. of Working Interest Owners 2-10	11-20	21+
2-30	$200	$325	$450
31-100	$325	$325	$450
100+	$450	$450	$450

* RIO = Royalty Interest Owners

[**Source:** Added at 10 Ok Reg 2601, eff 6-25-93]

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APPENDIX H. CALCULATIONS

PROCEDURE FOR CALCULATING LOADING RATE OF TOTAL SOLUBLE SALTS (TSS)

_____ ppm TSS in soil[1] X 2 = _____ lbs/ac TSS in soil

6,000 lbs/ac TSS - _____ lbs/ac TSS in soil = Maximum TSS (lbs/ac) to be applied _____

Maximum TSS (lbs/ac) _____ ÷ (_____ ppm TSS in pit materials[1] X .000001) = Maximum lbs/ac of pit materials to be applied _____

Maximum lbs/ac _____ ÷ _____ lbs/bbl = Maximum bbls/ac _____

PROCEDURE FOR CALCULATING LOADING RATE OF HEAVY METALS AND OIL AND GREASE

OCC Standard for the parameter _____ lbs/ac ÷ (_____ ppm in pit materials X .000001) = Maximum lbs/ac of pit materials to be applied _____

Maximum lbs/ac _____ ÷ _____ lbs/bbl = Maximum bbls/ac _____

PROCEDURE FOR CALCULATING MAXIMUM DRY WEIGHT

Weight of drilling mud[2] _____ lbs/gal x 42 = _____ lbs/bbl

200,000 lbs ÷ _____ lbs/bbl = Maximum bbls/acre _____

PROCEDURE FOR CALCULATING VOLUME OF PIT CONTENTS

$$V = \frac{(W_t \times L_t) + (W_b \times L_b)}{2} \times D \times .1781$$

Where, V = volume

W_t = width of pit in feet at top of pit contents.

L_t = length of pit in feet at top of pit contents.

W_b = width of pit in feet at bottom of pit.

L_b = length of pit in feet at bottom of pit.

D = depth in feet of pit contents to be soil farmed.

[1]Electrical Conductivity (EC expressed in micromhos/cm) may be used to estimate TSS: EC x 0.64 = ppm TSS.

[2]Based on laboratory analysis of Dry Weight.

[**Source:** Added at 12 Ok Reg 2017, 7-1-95]

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APPENDIX I. SOIL LOADING FORMULAS

TOTAL DISSOLVED SOLIDS

EC of receiving soil _____ micromhos/cm x 0.64 = _____ ppm TDS. TDS in receiving soil _____ ppm x 2 = _____ lbs/ac TDS in receiving soil.

6,000 lbs/ac TDS* - _____ lbs/ac TDS in receiving soil = Maximum TDS (lbs/ac) to be applied _____.

EC of materials to be applied _____ micromhos/cm x 0.64 = _____ ppm TDS.

Maximum TDS (lbs/ac) to be applied _____ ÷ (TDS of materials to be applied _____ ppm x .000001) = Maximum weight of materials to be applied _____ lbs/ac.

FOR LIQUID MATERIALS:

Maximum weight of materials to be applied _____ lbs/ac ÷ (sample weight _____ lbs/gal** x 42) = Maximum loading _____ bbls/ac.

Total volume of materials to be applied _____ bbls ÷ Maximum loading _____ bbls/ac = Minimum acres required _____.

FOR SOLID MATERIALS:

Maximum weight of materials to be applied _____ lbs/ac ÷ (sample weight _____ lbs/gal** x 202) = Maximum loading _____ cu yds/ac.

Total volume of materials to be applied _____ cu yds ÷ Maximum loading _____ cu yds/ac = Minimum acres required _____.

CHLORIDES

Cl in receiving soil _____ ppm x 2 = _____ lbs/ac Cl in receiving soil.

3500 lbs/ac Cl - _____ lbs/ac Cl in receiving soil = Maximum Cl (lbs/ac) to be applied _____.

Maximum Cl (lbs/ac) to be applied _____ ÷ (Cl of materials to be applied _____ ppm x .000001) = Maximum weight of materials to be applied _____ lbs/ac.

Maximum weight of materials to be applied _____ lbs/ac ÷ (sample weight _____ lbs/gal** x 202) = Maximum loading _____ cu yds/ac.

Total volume of materials to be applied _____ cu yds ÷ Maximum loading _____ cu yds/ac = Minimum acres required _____.

OIL AND GREASE[1]

40,000 lbs/ac O&G* ÷ (O&G of materials to be applied _____ ppm x .000001) = Maximum weight of materials to be applied _____ lbs/ac.

FOR LIQUID MATERIALS:

Maximum weight of materials to be applied _____ lbs/ac ÷ (sample weight _____ lbs/gal** x 42) = Maximum loading _____ bbls/ac.

Total volume of materials to be applied _____ bbls ÷ Maximum loading _____ bbls/ac = Minimum acres required _____.

Maximum bbls/ac ÷ 4.809 = Maximum cu yds/ac _____.

FOR SOLID MATERIALS:

Maximum weight of materials to be applied _____ lbs/ac ÷ (sample weight _____ lbs/gal** x 202) = Maximum loading _____ cu yds/ac.

Total volume of materials to be applied _____ cu yds ÷ Maximum loading _____ cu yds/ac = Minimum acres required _____.

DRY WEIGHT

Wet weight of drilling mud**_____ lbs/gal x _____ % Dry weight = _____ lbs/gal Dry weight.

_____lbs/gal Dry weight x 202 = _____ lbs/cu yd.

200,000 lbs/ac Dry weight ÷ _____ lbs/cu yd = Maximum cu yds/ac _____.

Total volume of materials to be applied _____ cu yds ÷ Maximum cu yds/ac _____ = Minimum acres required _____.

*Soil loading standards are based upon standards set forth in "Diagnosis and Improvement of Saline and Alkaline Soils," U.S. Agriculture Handbook 60. Pub. U.S. Salinity Laboratory, Riverdale, California, 1954; Moseley, H.R., "Summary and Analysis of API Onshore Drilling Mud and Produced Water Environmental Studies," 1983, American Petroleum Institute Bulletin D-19.

**Based on actual weight of composite sample of materials.

[1] GRO or DRO may be substituted for oil and grease

[**SOURCE:** Added at 12 Ok Reg 2039, 7-1-95; Amended in Rule Making 97000002, eff 7-1-97

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APPENDIX J. DEWATERING OIL ALLOWABLE TABLE

(100 percent of market demand)

Depth*	**Barrels Per Day**
To-3000	200
3001-4000	400
4001-5000	600
5001-6000	800
6001-7000	1000
7001-8000	1100
8001-9000	1200
9001-10000	1300
10001-	1400

* The depth in feet from the surface of the ground to the top of the producing formation in the oil well.

[**SOURCE:** Added in Rule Making 200100009, eff 7-1-02]

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