



Underground Injection Wells For Produced Water Disposal

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Agenda



- History
- Program Oversight
- Well Classifications
- Class II Wells
- Reclamation / Disposal Combinations
- Summary



- **1930s**

- ▶ Oilfield brine disposal (Texas)
- ▶ EOR Injection

- **1940s**

- ▶ Oil refineries inject wastes

- **1950s**

- ▶ Deep well injection of chemical wastes
- ▶ State regulations for brine disposal

- **1960s**

- ▶ Earthquake attributed to deep well injection in Colorado
- ▶ 1st documented cases of contamination in potential sources of drinking water



● 1970s

- ▶ Waste spilling from an abandoned oil well traced to paper mill injection well
- ▶ SDWA gives EPA authority to control underground injection

● 1980s

- ▶ UIC regulations
 - 5 well classes
 - Layout requirements for States to assume primacy
- ▶ SDWA amended to allow for existing oil and gas programs to regulate
 - Must be effective in protecting USDW
 - Must include UIC program components
- ▶ HSWA to RCRA
 - Hazardous waste injection more stringent
 - “No migration petition” – 10,000 years or rendered non-hazardous by reaction with surroundings



- **1990s**

- ▶ Class V management strategy
- ▶ 1st International symposium on deep well injection (CA)

- **2000 to present**

- ▶ Energy Policy Act (2005) excludes hydraulic fracturing from regulation under UIC program
- ▶ EPA initiates Study to Evaluate Impacts to USDW's by HF of CBM reservoirs
- ▶ Geologic sequestration of carbon dioxide (CO₂)



● Primary Enforcement (Primacy)

- ▶ States / tribes may request if they can demonstrate ability to meet minimum EPA requirements
- ▶ Some states / tribes share primacy with EPA
- ▶ Where neither of the above apply, EPA enforces UIC program through Region offices

Well Classifications



- **Class I**
 - ▶ Hazardous waste, non-hazardous liquids, municipal wastes
 - ▶ Inject under lowermost USDW
- **Class II**
- **Class III**
 - ▶ Extraction of minerals
 - Salt, uranium, sulfur
- **Class IV**
 - ▶ Banned (originally for hazardous or radioactive waste disposal into or above a USDW)
 - ▶ Currently limited to authorized clean-up sites
- **Class V**
 - ▶ All other wells
 - ▶ Inject non-hazardous liquids into or above a USDW
- **Class VI**
 - ▶ Geologic sequestration of carbon dioxide (CO₂)

Agenda



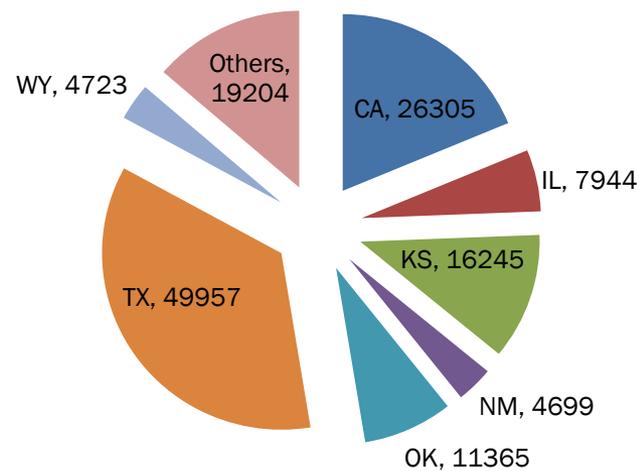
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Class II Wells



- Approximately 144,000 wells in the U.S.

- ▶ Majority in TX, CA, KS and OK



Class II Wells



- **~144,000 Class II Wells**
- **Enhanced Oil Recovery**
 - ▶ ~80% of all Class II wells
 - ▶ Water injection wells (WIW) most common, but also includes
 - Steam injection
 - Water - alternating - gas (WAG)
 - Simultaneous water and gas (SWAG)
 - CO₂ injection
- **Salt Water Disposal**
 - ▶ ~20% of all Class II wells
 - ▶ Used only for disposal of fluids associated with oil and gas production
- **Hydrocarbon Storage**
 - ▶ Used to inject and remove liquid hydrocarbons from underground storage (i.e. salt caverns)
 - ▶ Strategic Petroleum Reserve
 - ▶ More than 100 wells in the U.S. (<0.1% of Class II)



- History
- Program Oversight
- Well Classifications
- **Class II Wells**
 - ▶ Salt Water Disposal Wells
 - Selection
 - Well Construction
 - Volume / Pressure
 - Integrity Assurance
 - Economics
 - Pennsylvania / Texas Comparison
- Reclamation / Disposal Combinations
- Summary

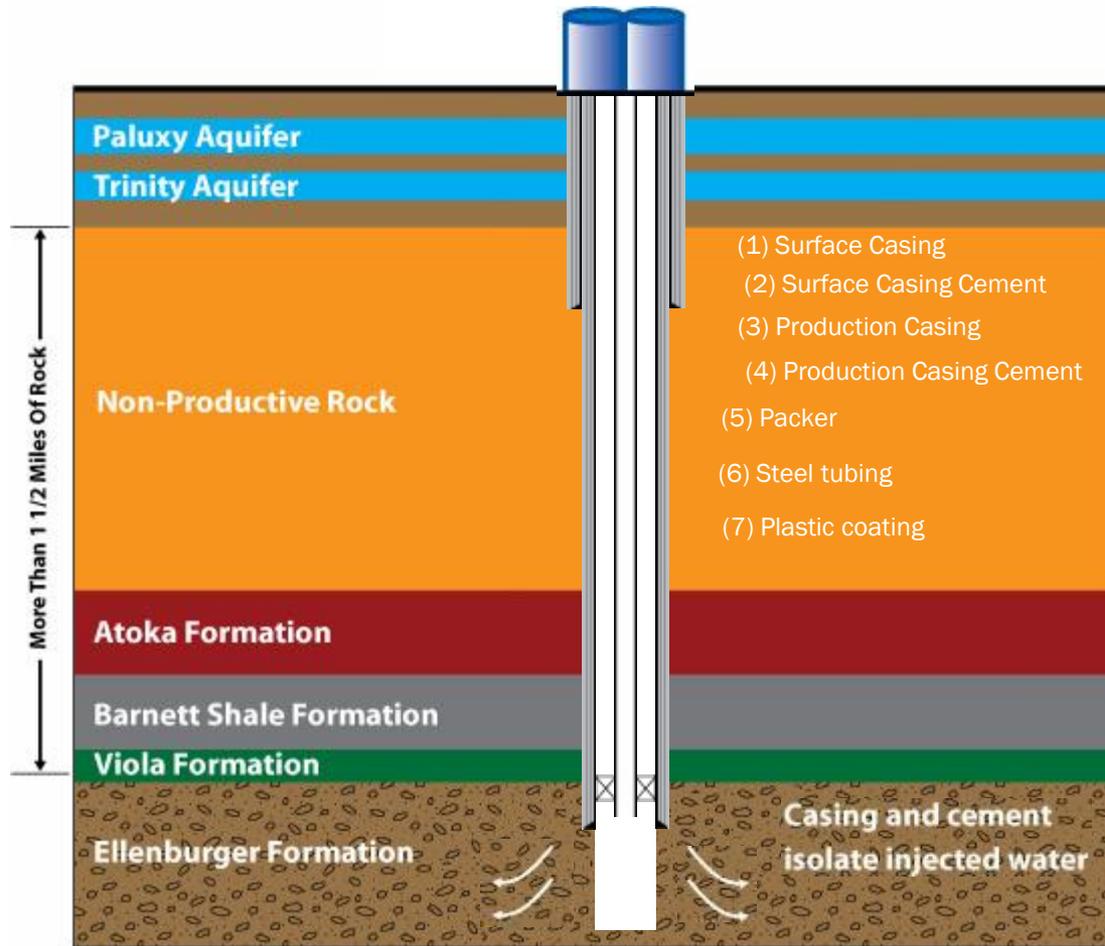
Salt Water Disposal Wells



● Selection

- ▶ Non-hydrocarbon bearing formation or an unproductive / depleted formation
- ▶ Barriers to USDWs
- ▶ Area Review
- ▶ Porosity
- ▶ Permeability
- ▶ Location, location, location!

Chesapeake Barnett SWD Construction



Texas Railroad Commission Monitoring & Testing

Drilling and Completion

- Casing*
- Cement*
- Tubing*
- Packer

Testing Prior to Service

- Cement Bond Log
- Pressure Testing

Operations

- Continuous Monitoring*
- Annual Integrity Testing*

Reporting

- Prior to Placing in Service
- Monthly
 - Injection Date
 - Pressure
 - Volume

*Areas in which Chesapeake exceeds Railroad Commission of Texas standards

Volume and Pressure



- Step rate tests utilized to confirm the rate and pressure required to “break down” or fracture the targeted formation
- Fracture gradient established based on step rate tests and instantaneous shut-in pressure (ISIP)
- Wells are typically permitted for a pressure and rate that does not exceed the frac gradient when pumping the typical brine for a known area



● Prior to service

- ▶ Cement bond / cement evaluation logs
- ▶ Pressure test casing

● During operation

- ▶ UIC minimum requirements
 - Mechanical integrity test – every 5 years
 - Monitor pressure – annually
- ▶ Many States have more stringent requirements
 - Texas
 - » Monitor and report mechanical integrity (H5) – minimum once every five years, but permit may specify more frequent
 - » Monitor injection pressure monthly & report annually (H10)

Economics



- **CHK SWD**

- ▶ Typically < \$0.25 / barrel

- **Commercial SWD**

- ▶ \$0.50 - \$2.50 / barrel
- ▶ Supply and demand

- **Trucking**

- ▶ \$1.00 / barrel / hour (average)
- ▶ SWD's plentiful (TX)
 - \$0.50 - \$1.00 / barrel
- ▶ SWD's scarce (PA)
 - \$4.00 - \$8.00 / barrel

- **Salt Water Pipelines**

- ▶ More efficient than trucking
- ▶ Reduces traffic and road wear

Pennsylvania / Texas Comparison

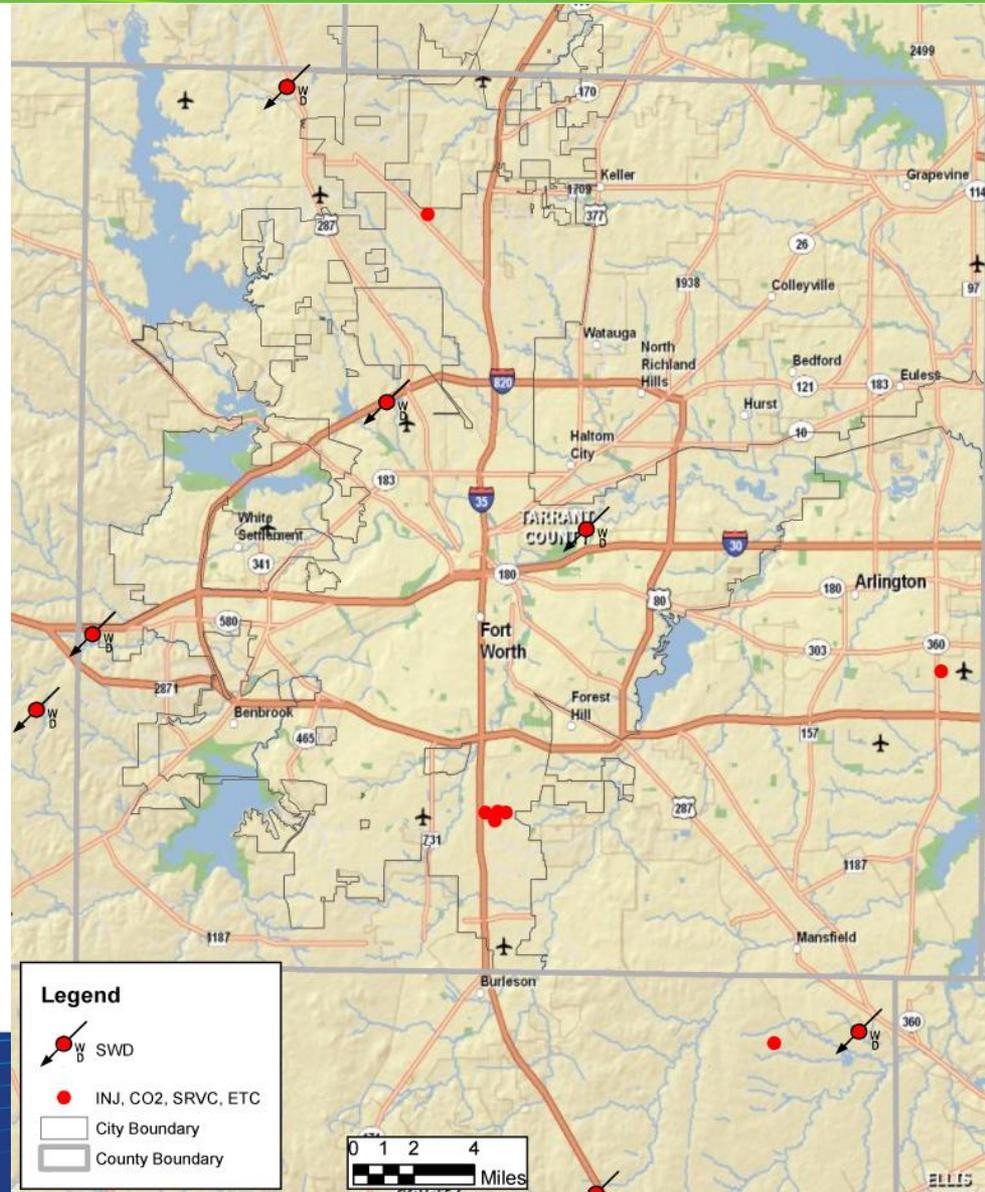


● Pennsylvania

- ▶ 8 Class II saltwater disposal (SWD) wells
 - Oriskany 3
 - Oriskany / Huntersville 2
 - Balltown 1
 - Gatesburg 1
 - Mine Void 1

● Texas

- ▶ ~12,000 Class II SWD wells
- ▶ Tarrant County – 10 SWD wells
 - All Ellenburger



Brentwood SWD Site



*Close-up of Brentwood SWD well
in East Fort Worth.*

Disposal Capacity



● Mann SWD – Cleburne, Texas

- ▶ Ellenburger Formation
- ▶ ~26,000 barrels per day (BPD)
- ▶ 9.5 million barrels per year

● Pennsylvania SWD's

▶ <u>Operator</u>	<u>BPD</u>
Columbia	700
EXCO	142
CNX	5,000*
Range	665
XTO**	120
Cottonwood	900
EXCO	140
Dominion	<u>1,000</u>
	8,667

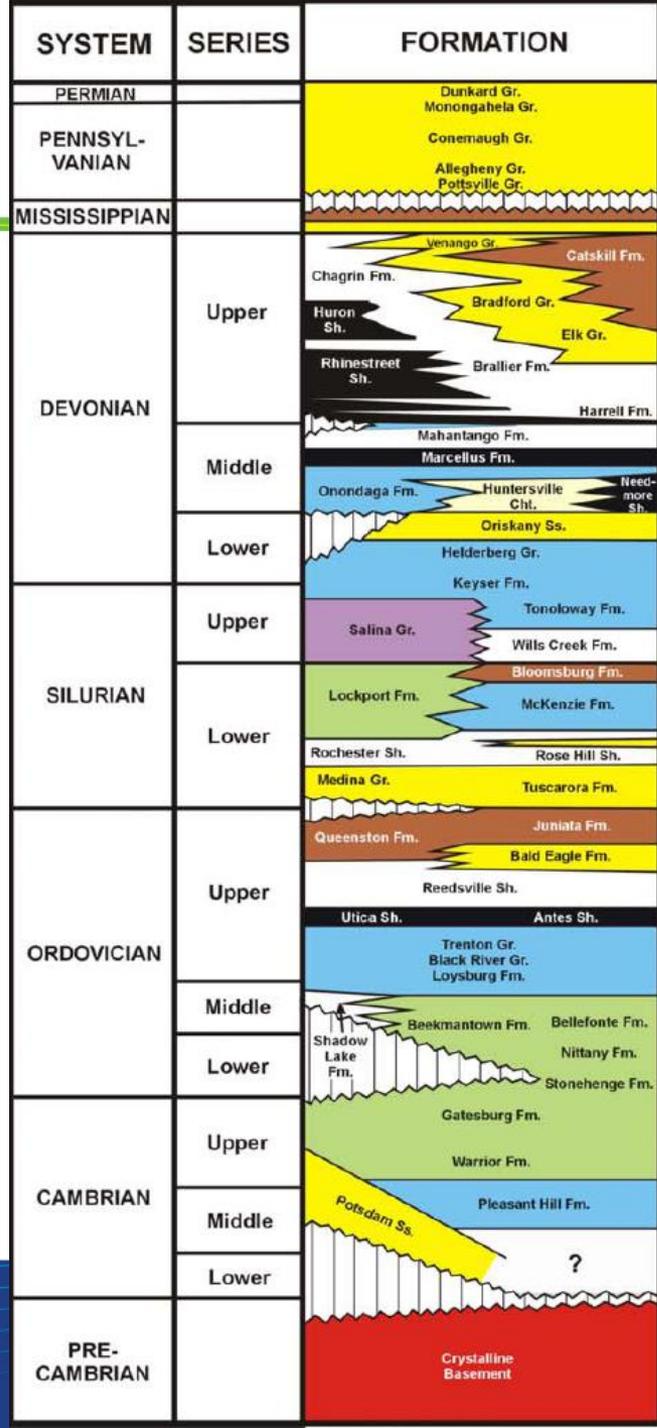
* - Mine void

** - Reported as recently plugged

PA Experience



- PA SWD Target
- Trenton / Black River
 - ▶ SE of Towanda, PA
 - ▶ Targeted total depth (TD) – 14,300'
 - ▶ Budgeted - \$3 MM
 - ▶ Final Spend - \$ 7 MM
 - ▶ Limited fluid capacity
 - ▶ Well TA'd
 - Permanent bridge plug @ 12,000'



Water Reuse



- **Lack of Suitable Disposal Infrastructure / Capacity in PA Originally Resulted in Produced Water Being Trucked (or railed) to Ohio and West Virginia**

- **Aqua Renew**



Aqua Renew
CHESAPEAKE ENERGY'S WATER RECYCLING INITIATIVE

- ▶ Filtration and reuse
- ▶ Central filtration sites
- ▶ Bermed and lined
- ▶ Steel tanks for storage of all produced brine

- **Benefits**

- ▶ Decreases fresh water demand by 10-15%
- ▶ ~52,500 less truck road miles per well for water disposal
- ▶ CO₂ emissions reduced by ~88 metric tons per well

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Brentwood SWD Site



Reclamation / Disposal Combinations



- Economics can work in areas where disposal capacity is limited
- Water quality (total dissolved solids - TDS) greatly influences economics
- Capacity multiplier – particularly with relatively low TDS brine
- Concentrated brine requires less energy for disposal
- Evaporative systems – no backhaul of treated water

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Summary



- The Oil and Gas Industry Has Utilized Underground Injection of Brine Since the 1930's and Class II UIC Wells Currently Inject Two Billion Gallons of Fluid Per Day For Enhanced Oil Recovery, Disposal and Storage.
- Wells Used Exclusively To Dispose of Fluids From Oil and Gas Production Account For 20% of the 144,000 Class II Wells in the U.S.
- Brine Disposal in Class II Wells Is Safe, Environmentally Sound and is the Most Economic Option in Most Areas.
- In Areas of Limited Disposal Capacity or Where Water Resources Are Stressed, Reuse of Produced Brine is Proving To Be an Effective Alternative To Underground Injection.



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Introduction

The Oil and Gas Industry first utilized underground injection as a means of disposing of the naturally occurring brine that was often produced along with crude oil and / or natural gas in the 1930's. In 1974, the Safe Drinking Water Act required the U.S. Environmental Protection Agency (EPA) to set minimum requirements for the brine injection wells utilized by the Oil and Gas Industry along with numerous other wells used for disposal of various hazardous and nonhazardous wastes. These requirements are generally referred to as the Underground Injection Control (UIC) program. Since inception of the UIC program, Class II wells (those wells classified for injection of oil and gas liquids including oilfield brine disposal wells) have safely injected over 33 trillion gallons of oilfield brine without endangering underground sources of drinking water (USDW).

History of Underground Injection

During the 1930's, oil producers first began disposing of the brine produced in conjunction with crude oil back into the same formation from which it had been extracted. In this same decade, the practice of injecting produced brine into a formation in order to push crude oil to an adjacent producing well was initiated, thus starting the practice of enhanced oil recovery (EOR). In the 1940's, oil refineries began using deep well injection for disposal of refinery waste and several chemical plants followed this trend a decade later. As the practice of brine disposal using deep well injection continued to grow, many states began implementing regulations for disposal of oilfield brine in the 1950's. In the 1960's, documented cases of groundwater contamination associated with the underground injection of waste began to surface. Most notably, a waste injection well at the Hammermill Paper Company in Erie, Pennsylvania suffered a casing failure and pulping liquor escaped into the surrounding ground and into Lake Erie. Though never conclusively determined, a black liquid found to be flowing from an abandoned oil well approximately five miles from the Hammermill well was believed to be pulping liquor from the Hammermill well.

In response to this and other cases, the U.S. Congress passed the Safe Drinking Water Act in 1974 and gave the EPA the authority to regulate the underground injection of all wastes in order to protect USDW's. In the following decade, Federal UIC regulations were passed establishing five classes of wells that fall under the UIC program and requirements for States or tribes to have primary enforcement, or primacy, on their lands. Since its creation, the UIC program has been amended to allow for stricter regulations for deep well injection of

hazardous waste and to create a sixth well classification for wells that will be used for geologic sequestration of carbon dioxide (CO₂).

Primary Enforcement (Primacy)

As mentioned above, the Federal UIC regulations established the requirements necessary for a State or tribe to enforce the program on their lands. In order to assume primacy, the States or tribes had to demonstrate their program for UIC enforcement met the minimum requirements established by the EPA's UIC program. Currently, 33 States and three U.S. Territories have primacy for all of the UIC wells in their jurisdiction. Seven States, but none of the U.S. Territories, share primacy with the EPA, often with a State handling one or more classifications of wells and the EPA overseeing the remaining classifications. The EPA maintains primary enforcement of the UIC programs in the remaining ten States and three US Territories.

Well Classification

Under the Federal UIC regulations, there are currently six different well classifications.

Table 7. UIC well classifications

Class I	Wells that inject hazardous wastes, non-hazardous industrial wastes and municipal wastewater beneath the lowermost USDW.
Class II	Wells that inject fluids for enhanced oil recovery, dispose of fluids associated with oil and gas production and inject liquid hydrocarbons for storage.
Class III	Inject fluids for the extraction of minerals such as salt, sulfur and uranium.
Class IV	Originally used for wells that injected radioactive or hazardous waste above a USDW, but this process has been banned. This classification is now limited to wells that are being used for an authorized clean-up of a contaminated site or groundwater source.
Class V	Wells that inject non-hazardous waste above a USDW. Basically is composed of all wells that do not fit into any other category.
Class VI	Newest well classification. Intended for wells that will be used for sequestration of carbon dioxide.

Class II Wells

At present, there are approximately 144,000 Class II injection wells in the U.S. Of these, roughly 80% are wells used for enhanced oil recovery (EOR). Most prominent of this group are water injection wells that re-inject brine taken from a producing formation back into that formation in an effort to pressure more crude oil to the producing wells. This subset of Class II wells also includes wells used to inject steam into formations containing viscous crude and wells used to inject various mixtures of gas and / or brine to improve crude production. The smallest subset of Class II wells is the wells that are used to inject liquid hydrocarbons into underground storage caverns. Most recognizable of this set of wells are those utilized for the U.S. Strategic Petroleum Reserve. The remaining Class II wells, approximately 20% of the total, are those wells that are used to dispose of the fluids associated with oil and gas production, more commonly referred to as saltwater disposal wells.

Saltwater Disposal Wells (SWD)

This special subset of the Class II UIC wells has allowed for the safe disposal of fluids associated with oil and gas production since the 1930's and has a long track record of protecting USDW's under the UIC program. Oil and Gas Companies have come to rely on the safe and economic operation of these wells for disposal of the naturally occurring brine that often accompanies the production of oil and / or gas. Whenever an Oil and Gas Company or a commercial SWD Operator decides to establish a SWD in a new area, the first consideration is site selection.

The surface location of an SWD well is important as it needs to be an area where it is easily accessible by Operators who need to dispose of brine from their oil and gas production efforts; however, surface location is not the only consideration when selecting a site for the SWD well. Additionally, the SWD Operator needs to understand the geology beneath the surface location. The first consideration is for a porous and permeable, non-hydrocarbon bearing zone that is not considered an aquifer under the UIC program. A previously productive oil and gas zone that is now depleted and is porous and permeable is also suitable for brine disposal. In either of these options, there must be a clear barrier between the zone of interest and all USDW's and the area to be drilled must be relatively clear of any geologic faults. Once the site selection is complete, the well may be drilled and completed provided certain minimum requirements in the UIC program are adhered to.

Once drilling commences on the well, the first requirement under the UIC program for the area is the depth at which surface casing must be run. Usually, surface casing is run from surface to a depth that is several hundred feet beyond the deepest know aquifer in an area. Once surface casing is set, cement is circulated into the void between the steel casing and the bored hole, forming an impermeable seal across any aquifers. The well is then drilled to the desired depth for the zone targeted for disposal. Again, steel casing is run from surface to the total depth of the well and cement is circulated into the area between the casing and the borehole from the bottom of the well to surface, forming another dual layer of protection to isolate the injected fluids from any USDW. A cement bond or evaluation log is usually run at this point. The cement evaluation log is a sonic tool that can give a 360° interpretation of the quality of the cement bond to the casing's outside diameter. At this point, a special tool is used to open holes in (or perforate) the casing and cement across the disposal zone.

Injection tubing (usually internally plastic coated to protect the pipe from corrosion) and a packer are run into the well. The packer is a device that seals the annular space between the casing and tubing and prevents the fluid being injected via the tubing from coming back up hole. The UIC program often dictates the depth at which the packer must be located, but it is usually somewhere between 50' and 100' above the uppermost perforation. After running the packer and tubing into the well, a packer fluid is circulated through the tubing and back up the annular space to surface before the packer is "set" or activated. Packer fluids serve three primary purposes: 1) protect the casing inside diameter and tubing outside diameter from corrosive agents, 2) provide a hydraulic fluid to allow for instantaneous notification on the surface should the packer leak injection fluid into the annular space and 3) provide hydrostatic

head pressure to help offset the pressure on the bottom of the packer from the injection fluid. After the packer is set, UIC regulations require that the mechanical integrity of the injection casing and packer seal be tested and verified. This is usually done by applying pressure to the annular fluid and using a chart recorder to document that the pressure remains constant in a static condition for a period of time (e.g. 30 minutes). Once a well has been placed in service, the UIC regulations require that, as a minimum, the wellbore integrity be verified via a recorded pressure test once every five years and the normal operating annular pressure be observed and recorded once per month. Many of the oil and gas regulating divisions in States with primacy have more stringent requirements. In Texas, for example, a recorded pressure test for casing integrity (H5 test) must be performed annually on each Class II well.

The next required step in the UIC process is a step rate test to determine maximum surface injection pressure. In a step rate test, a fluid similar to that expected to be injected into the well once it is in service is pumped into the well at gradually increasing rates. Each rate is maintained for a required period of time, usually either 30 or 60 minutes. Bottomhole pressure is recorded during this period. When plotting the dynamic bottomhole pressures for each injection rate, the point at which the fracture gradient for the targeted formation is exceeded will be seen as an inflection in the slope of the line through the pressure points. After noting that the formation has “broken down” or indicated that fracture formation has initiated, pumping may be stopped and the instantaneous shut in pressure (ISIP) recorded. Maximum surface injection pressure is often set at or just below the ISIP, allowing for hydrostatic head of the injected fluid and friction loss in the injection tubing. In the event that formation breakdown is not noted in the test, maximum surface injection pressure is usually set to reflect the highest pressure seen during the step rate test. UIC regulations generally require that all step rate tests be witnessed by a representative for the local UIC administrator.

After a saltwater disposal well has been properly constructed, the economics of operation often complement this time-proven method of brine disposal. For a saltwater disposal well that is operated by an Oil and Gas Company for disposal of the brine produced during normal operations, the average cost of disposal is often less than \$0.25 per barrel of fluid disposed. A commercial SWD well will typically charge between \$0.50 and \$2.50 per barrel of fluid. As with most things in life, this price disparity is usually related to supply and demand. In areas where disposal wells are plentiful and generally operate below capacity, competition drives the price down. In areas where there is a strong demand for brine disposal, but the disposal infrastructure has not been developed or the subsurface geology is not conducive to underground injection of oil and gas fluids, the commercial operators can receive a premium for their services.

A second cost associated with disposal of oilfield brine is transportation of the brine from where it is gathered and stored at the well site to the disposal well. On average, the transportation of brine will cost an Operator \$1.00 per barrel of brine per hour of transportation time. In an area such as the Barnett Shale in North Texas where SWD wells are plentiful, brine transportation may only add \$0.50 per barrel to the cost of brine disposal. Conversely, in northern Pennsylvania, where the nearest commercial disposal well may be in

Ohio or West Virginia, the cost of transportation can easily add \$4.00 to \$6.00 per barrel to the cost of disposal.

Lastly, in addition to the cost of transportation in this area, an Operator needs to consider the wear and tear on local roads from the long distance transportation of the brine along with contribution of carbon dioxide emissions from the trucks required to transport the brine.

Consideration of these three items led Chesapeake Energy to develop our unique Aqua Renew™ program to allow for reuse of produced brine from our Marcellus wells. By filtering and reusing the brine in an upcoming completion, Chesapeake not only reduces the amount of fresh water required for the completion, but we can also eliminate seven hours of truck time that would have been used to transport brine to an out of State disposal well. This reduction in truck transportation of brine will also reduce 52,500 road miles of wear per well and eliminate 88 metric tons of carbon dioxide emissions per well.

The subsurface geology in Pennsylvania has not proven to be conducive to brine disposal. To date, there are only eight permitted Class II wells devoted to saltwater disposal in the entire state. Of these eight, three utilize the Oriskany formation for disposal and two use a combination of the Oriskany and Huntersville formations. One well injects into the Balltown formation and another the Gatesburg zone. Lastly, the highest disposal volume of the set injects into a mine void. As a group, the eight wells account for 8,667 barrels per day of brine disposal capacity. By comparison, the Mann #1 SWD well operated by Chesapeake near Cleburne, Texas (Barnett Shale) averages 26,000 barrels per day of brine disposed. The Mann #1 injects brine into the Ellenburger Formation, a porous strata located 1 ½ miles beneath all known aquifers in the area. Tarrant County, of which Fort Worth, Texas is the county seat, has more saltwater disposal wells (ten) than the entire State of Pennsylvania. Overall, the State of Texas has approximately 12,000 Class II saltwater disposal wells.

While the overall subsurface geology in Pennsylvania may not be ideally suited to subsurface brine injection, Chesapeake did attempt to drill and complete a Class II well in the Trenton / Black River formations. Originally budgeted for three million dollars, ultimate capital spent on this well was just under seven million dollars and numerous tests indicated very limited brine uptake capacity. A permanent bridge plug was set above the targeted formations and the well was temporarily abandoned.

Reclamation / Disposal Combinations

In areas where disposal opportunities are limited or disposal capacity in a given well is less than plentiful, it may be advantageous to utilize some form of water reclamation upstream of the disposal well. Of the reclamation systems available to the industry, all have differing costs and efficiencies associated with brine concentration and some are limited in consideration by organics or the total dissolved solids concentration of the fluid to be treated. To an Operator, another key consideration is whether the unit produces a distilled water or water vapor. If it is distilled water and the unit is east of the 98th Meridian, the distilled water must be trucked back to a completion location to be used in an upcoming stimulation. A provision of the Clean

Water Act allows Operators to request permission from the EPA to surface discharge treated produced fluids for the beneficial use of agriculture or for wildlife propagation – provided the discharge location is west of the 98th Meridian. If discharge of treated water is not allowable and available water resources are abundant, a reclamation system that produces water vapor while concentrating the brine for disposal will save road wear and reduce carbon dioxide emissions from truck traffic.

By concentrating the brine prior to disposal, these units may make economic sense in area where disposal capacity is limited. If the produced brine chemistry allows for recovery of 75% of the treated water volume as vapor, the remaining brine volume will be reduced by a factor of four. Reclaiming this fluid prior to disposal allows for a disposal site that has a maximum daily capacity of 500 barrels of water to process 2,000 barrels of fluid per day. Of the processed 2,000 barrels, 1,500 are returned to the water cycle as vapor and the remaining 500 barrels of concentrated brine are sent down the Class II disposal well.

Chesapeake Energy is trialing such a unit at our Brentwood disposal site just east of downtown Fort Worth. Two EVRAS (evaporative reduction and solidification system) units manufactured by Layne Christensen's Intevras Division utilize waste heat from the Ark Park compressor site to treat 1,200 barrels per day of produced water. Of these 1,200 barrels, roughly 700 are evaporated as water vapor. The result is that the initial 1,200 barrels are concentrated down to 500 barrels before injection into the Brentwood SWD well. Though not economically favorable to the standard Barnett Shale practice of straight disposal of oilfield brine, the Brentwood application allows us to properly test out application of the technology for other areas.

Conclusions

- The Oil and Gas Industry has utilized underground injection of brine since the 1930's and Class II UIC wells currently inject two billion gallons of fluid per day for enhanced oil recovery, disposal and storage.
- Wells used exclusively to dispose of fluids from oil and gas production account for 20% of the 144,000 Class II Wells in the U.S.
- Brine disposal in Class II wells is safe, environmentally sound and is the most economically viable option in most areas.
- In areas of limited disposal capacity or where water resources are stressed, reuse of produced brine is proving to be an effective alternative to underground injection.