The basics of deep well injection as a leachate disposal option – technical, economic and regulatory considerations

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ABSTRACT

Deep well injection is a viable leachate management option in many parts of the United States, yet it is often screened out as a viable alternative due to a lack of understanding of the technology or gross misconceptions about its acceptance or applicability. The purpose of this paper is to present the basics of deep well injection as a technology and to present three key threshold criteria a facility should evaluate when considering the applicability of geologic sequestration of leachate.

Technical criteria that will be discussed are potential disposal volumes, geologic suitability, chemical compatibility, pre-treatment requirements, and leachate chemistry. The economic considerations are evaluated based on the technical criteria noted above, management of public perception/relations, current leachate management expenditures, service life of the asset and risk to develop accurate capital, O&M costs, and return on investment. Regulatory considerations will include the role of state vs. federal primacy for each state, the general stance of regulatory acceptance in specific areas of the United States, and a discussion of the permitting process and typical reporting requirements.

These key considerations are then integrated into an overall suitability evaluation that an owner can utilize to accurately determine if deep well injection is a viable option and, if so, how to educate other stakeholders and manage the process of implementation as a project moves forward.

INTRODUCTION

Understanding the entire range of wastewater management and disposal alternatives can be a daunting task, particularly as increasingly stringent surface water discharge standards take effect or as zero discharge facilities find their liquids management needs changing over time. Former solutions are no longer options, or may be too costly. One alternative that is rapidly gaining traction is deep injection wells.
Deep well injection is a viable leachate management option in many parts of the United States, yet it is often screened out as a viable alternative due to a lack of understanding of the technology or gross misconceptions about its acceptance or applicability. The purpose of this paper is to present the basics of deep well injection as a technology and to present three key threshold criteria a facility should evaluate when considering the applicability of geologic sequestration of leachate.

Regulatory considerations will include a brief history of the use of deep injection wells for fluid disposal, the role of state vs. federal primacy for each state, the general stance of regulatory acceptance in specific areas of the United States, and a discussion of the permitting process and typical reporting requirements.

Technical criteria that will be discussed are geologic suitability, potential disposal volumes, chemical compatibility, pre-treatment requirements, and leachate chemistry.

The economic considerations are evaluated based on the technical criteria noted above but also include management of public perception/relations, service life of the asset and risk to develop accurate capital, O&M costs and return on investment.

These key considerations are then integrated into an overall suitability evaluation that the permittee can utilize to determine if deep well injection is a viable option and, if so, how to educate other stakeholders and manage the process of implementation as a project moves forward.

1.0 BASICS OF DEEP WELL INJECTION

Deep injection wells (DIW) mean different things in different parts of the country. For example, in the Midwest, DIWs have been used for decades to dispose of industrial waste water, mining effluent, and produced water from oil and gas production activities; and range from 3,500 feet to more than 10,000 feet deep. In Florida, DIWs also have been used since the 1960s; however, they are used to dispose of treated municipal wastewater, unrecyclable farm effluent, and landfill leachate. This paper will focus on industrial type disposal wells which are significantly more advanced and protective of groundwater than the Class 2 oil and gas wells people most commonly associate with deep injection practices.

Class 1 DIW’s are constructed using a series of casings set in the ground where the initial casing starts out large, and subsequent casings become smaller in diameter, progressively telescoping downward. Outer casing materials are typically steel alloys, and innermost tubing may be fiberglass for better chemical resistance. As a casing is set and rock below it is drilled out, the next casing is set and cemented with a chemically resistant grout. The process continues with each progressively deeper casing. These redundant “seals” are what keep the injected liquid from escaping and migrating vertically into the protected aquifers.
A DIW typically has three upper casings to protect the aquifers and isolate the wastewater to the desired disposal zone: surface casing, intermediate casing, and longstring casing. The inner casing, called the injection tubing, extends to the injection zone. Mechanical packers seal the space between the injection tubing and the last protective casing. The resulting annular space is filled with a non-corrosive fluid. This fluid is pressurized to demonstrate continuous mechanical integrity of the well, or to show that there is no migration of fluid into or out of the annular space. The annulus is monitored for potential leaks, which would register as a loss in pressure and promptly stop the injection. Figure 1 is a simplified view of a typical deep injection well.

DIW’s have an advantage over other liquids disposal options because they can accommodate various types of wastewater. DIWs are being used on a large variety of waste streams that continues to expand, including:

- CCR and MSW Leachate
- Contaminated Groundwater (i.e., ammonia or VOC – impacted)
- Reverse osmosis treatment concentrate
- Various other industrial wastewaters (refinery, chemical plants, and meat packing)

There are approximately 800 Class 1 injection wells operating in the United States, with most located in the Great Lakes and Gulf Coast areas, but other locations are certainly suitable, providing they meet the technical criteria discussed below.

Over 80% of these wells inject a non-hazardous waste stream, and this paper will focus on the regulatory, technical, and economic considerations of using this non-hazardous type of Class 1 injection well.

2.0 REGULATORY FRAMEWORK

DIW’s are regulated by the U.S. Environmental Protection Agency (USEPA) under the 1974 Safe Drinking Water Act, and the USEPA has set stringent criteria governing the construction and operation of Class 1 DIW’s. The USEPA has delegated this permitting authority or primacy to 33 states, which have regulatory programs that meet or exceed the minimum standards established by the USEPA. The USEPA Primacy map for the United States is presented as Figure 2 below:
2.1 RESPONSIBLE FLUID DISPOSAL OPTION

The USEPA Underground Injection Control (UIC) program is designed with one goal: protect the nation’s aquifers and the underground sources of drinking water (USDW). There are several protective measures in a DIW design and operation that are intended to meet this objective.

1. Proper design of the well casings and injection tubing for strength and chemical compatibility. These components are recertified a minimum of every five years with a robust mechanical integrity testing program to demonstrate that the well and its various components are not leaking.

2. Demonstration that there is a confining zone of low permeability rocks to prevent upward migration of injected fluids into the USDW. This demonstration includes documenting that any other nearby wells or borings drilled into the confining zone have been properly completed or plugged to prevent a short circuit contamination pathway.

3. Testing the injection interval to prove it can accept the fluids at the proposed rates and pressures.

4. Continuous monitoring of the well pressures and flows that include the well annulus monitoring.
5. Frequent sampling and reporting of the injected fluid.

6. Financial assurance via various means to plug and abandon the well if required.

2.2 GENERAL REGULATORY ACCEPTANCE AND PUBLIC PERCEPTION

Most USEPA regions or states have a favorable outlook on the proper use and operation of a Class 1 DIW. This is based on a good compliance history by the Class 1 permittees and increasingly stringent surface water discharge criteria and number of facilities that are permitted as zero discharge. The USEPA has concluded that the current practice of deep well injection is both safe and effective, and poses an acceptably low risk to the environment (1). In 2000 and 2001, other studies by the University of Miami and USEPA, respectively, suggested that injection wells had the least potential for impact on human health when compared to ocean outfalls and surface discharges (2). Regulators generally have the program knowledge and technical sophistication to understand the needs of industry and that fluid disposal options can be a challenge to facility owners.

There are varying public perspectives on DIW’s across the United States which are often influenced by negative press that originates from the oil and gas industry, and their disposal practices, which historically have had much less regulation, oversight, or permitting requirements. The public perception component of permitting a DIW is usually based on what is conveyed about hydraulic fracturing of oil and gas wells that may not even be close to the subject site. The permittee should be aware of this potential permitting hurdle and consider what a proactive public relation program may do to facilitate public and regulatory acceptance.

2.3 TYPICAL PERMITTING PROCESS & REPORTING REQUIREMENTS

The permitting process usually starts with an internal feasibility study that evaluates the regulatory framework, geologic conditions, and a screening level cost estimate for a DIW. That information is typically utilized to start a conversation with the regulatory agency and let them know the permittee’s facility is considering a DIW as a liquids management option. These early meetings with regulators allow the permittee to identify key permitting criteria, and anticipated review timeline so the permit application proactively addresses these items. It also allows the regulators to put a face to a name and build a rapport with the specific staff that will be in charge of reviewing the permit application.

The specific permitting requirements address the siting, construction, operation, monitoring and testing, reporting and record keeping, and closure of Class 1 wells. The next step is the preparation of a comprehensive permit application that presents the technical justification for the construction and operation of a DIW.
The permit application preparation can take anywhere from 3 weeks to 3 months, depending on the proximity of other deep geologic information and the maturity of the respective agency’s UIC program. Some states, such as Florida, have a large number of DIWs and the geology is well understood, reducing the permitting effort considerably. Other states have more robust permitting requirements due to variations in geologic conditions and require extensive geologic studies to demonstrate the technical feasibility of a DIW. These factors are outlined in more detail in the technical criteria section below. Similar to other permitting efforts, once the permit application is reviewed by the agency, the applicant may receive a comment letter from the agency and provide a response. The application and any responses are then utilized to prepare a draft permit for public notice and comment. The public notice period is usually 30 days and if significant comments are received, the agency may decide to have a public meeting to discuss and address those comments prior to issuing a permit to construct a DIW. The public education component of the permitting process is discussed in more detail under the risk section of economic considerations of this paper. After a permit to construct is issued, the well is drilled and surface facilities are constructed. The permit application is then revised to note any changes in geologic conditions and includes as-built drawings and site-specific information of the facility.

Once the well is operational, the permittee has to submit monthly and/or quarterly reports on the injection rate, pressure, and any constituents of concern in the injected fluid, or influent. There is also a required annual comprehensive influent characterization. Other testing requirements include an annual pressure fall off test to gauge the well’s performance over time, and then every 2 to 5 years the permittee has to conduct mechanical integrity testing to demonstrate the well is not leaking.

The overall timeframe from project planning to operational start-up usually takes 2 to 3 years, but projects can be fast tracked if there is preliminary and continued regulatory engagement, budgets are forecast accurately, and information is available to facilitate the permitting process.

3.0 TECHNICAL CRITERIA

3.1 Geologic Suitability

The primary technical criteria for permitting and operating a DIW is the geologic suitability of the facility. The geologic conditions required for demonstrating the suitability of an injection well are:
• An injection zone that consists of geologic formation(s) with sufficient thickness, porosity, and permeability that can accept the fluids at the proposed injection rate and pressure required to handle the anticipated disposal volumes. These are typically high porosity limestones, dolomites, or sandstones at depths exceeding 3,000 feet.

• A confining unit comprised of a shale, low permeability limestone, or sequence of such rock types that prevent the upward migration of the injected fluids from the injection zone. These are typically 200 to 1,000 feet above the injection zone, but below the base of the USDW.

• A lack of artificial penetrations (oil and gas wells, mining and exploration related boreholes) within the ¼ to 2-mile area of review (AOR). Any artificial penetration that is deeper than the top of the designated confining unit must show that it was properly plugged and abandoned to not act as conduit for upward fluid migration.

• A fault and induced seismicity evaluation is also prepared that considers the proposed location with respect to known faults and the potential for the injection well to induce earthquakes at the proposed rates and pressures. The induced seismicity component is not required in all jurisdictions but may have local implications in areas such as Texas, Kansas, and Oklahoma due to high volume disposal of oil and gas related liquids in certain areas.

3.2 Well Design

The design of a well includes how deep each casing is set and is based on the site-specific geology. It encompasses surface, intermediate, and longstring casing components that are protective of the local aquifers and allow the deeper geologic testing to be conducted in a stable bore hole. After the casing depths are determined, the well diameter is considered based on the proposed injection requirements. Each well is sized based on injection tubing size required to handle the desired flows. Subsequently, outer casing diameters are sized to accommodate the flow rates needed. Depending on the disposal requirements, a well can have disposal tubing as large as 12 inches down to 2 7/8 inches for flows ranging from 1,400 gallons per minute (gpm) to 100 gpm, respectively, and result in longstring casing diameters from over 18 inches to 7 inches. The casing depth and diameters are the main factors that influence DIW capital costs.

3.3 Chemical Compatibility

Any wastewater considered for disposal must be compatible with the target formation and the final casing material. Therefore, depending on the wastewater, it may be straightforward to use existing industry references to confirm compatibility. In some cases, laboratory bench tests may be necessary to make a final chemical compatibility determination.
Compatibility evaluations also consider the potential for creating unwanted microbial growth and scale formation within the injection interval. Growth and scale can happen with injected fluid that contain sulfur or ammonia (two food sources for microorganisms) or wastewaters supersaturated with minerals. Unless planned for and evaluated properly, these items have the potential to clog the formation around the well, significantly reducing flow and increasing back pressure. This can result in higher energy costs, regulatory action, and significant, unplanned costs to rehabilitate the well.

3.4 Surface Facilities Design

The DIW downhole design and chemical compatibility evaluation are used as the design basis criteria for the surface facilities design. The surface facility design considers the following items:

- Use of appropriately sized injection pumps, if gravity injection is not an option
- Pre-treatment considerations for solids removal that may be as low as 5 to 10 microns for sandstone injection zones
- Disinfection for algae and bacteria mitigation
- Sequestering agents
- Mass removal of inorganics to prevent scaling

The geologic suitability, well design, chemical compatibility evaluation, and surface facility design are typically developed to the conceptual design stage in the permitting process. These component are finalized once the well is drilled and specific reservoir pressures and injection zone physical and chemical characteristics are confirmed.

4.0 ECONOMIC CONSIDERATIONS

Understanding the drivers behind DIW design and operation are the only way to accurately estimate the costs for this leachate management option. Oftentimes, DIW costs are overinflated in screening level cost estimates because the lack of specific knowledge about this technology leads the practitioner to be overly conservative in developing cost projections.

Once an initial feasibility study has been conducted, there is usually enough information available to develop screening level cost estimates. After preparation of the permit and more information about site-specific geology, well design, and surface facilities design is available, capital and O&M budgeting level estimates can be prepared with greater accuracy.

4.1 Estimates of Capital and O&M Costs

Due to the wide range of geologic conditions, depths, and fluid disposal requirements, there is no one-size-fits-all estimating rule for DIW capital or O&M costs. Some general ranges are outlined in Table 1 below for various well depths and locations.
Table 1- Example Capital and O&M Costs for DIW’s

<table>
<thead>
<tr>
<th>Location</th>
<th>Depth (ft)</th>
<th>Injection Rate (MGD)</th>
<th>Pressure (psi)</th>
<th>Capital Cost</th>
<th>Annual O&amp;M Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Florida</td>
<td>3,500</td>
<td>2.0</td>
<td>40</td>
<td>$6.3M</td>
<td>$225K</td>
</tr>
<tr>
<td>South Illinois</td>
<td>12,000</td>
<td>0.43</td>
<td>2,000</td>
<td>$6.1M</td>
<td>$450K</td>
</tr>
<tr>
<td>Southwest Illinois</td>
<td>3,600</td>
<td>0.5</td>
<td>1500</td>
<td>$3.3M</td>
<td>$325K</td>
</tr>
<tr>
<td>Kansas</td>
<td>3,500</td>
<td>0.45-1.25</td>
<td>Gravity</td>
<td>$1.6M</td>
<td>$120K</td>
</tr>
</tbody>
</table>

(1) O&M costs based on power, pre-treatment and amortized testing requirements

The examples outlined above all had unique design criteria to fit the permittee’s specific requirements and often included a larger casing program in anticipation of growing disposal needs in the future.

The service life of DIW as a capital asset often exceeds 20 years and provides a stable, long-term fluid disposal option for the permittee. Like any other asset, it needs to be operated and maintained properly to reduce unnecessary operations and maintenance expenses.

4.2 Financial Assurance Requirements

DIW permittees are required to have a financial assurance mechanism in place before a construction permit is issued. The purpose of the financial assurance is to allow for third-party plugging and abandonment of the well in case a permittee defaults on this obligation.

4.3 Return on Investment

The economic factors for each project vary based on the geographic location of the well, geology, steel prices, and status of the oil and gas market (since most drillers are not solely Class 1 DIW service providers). However, based on information from past projects, most clients see an 18 to 36 month return on investment after DIW operation commencement.

4.4 Other Risk Factors to Consider

Stakeholder Engagement

A potential risk factor to consider in today’s connected world is an unfavorable public reaction. The public has become more sophisticated and is typically joining with various environmental groups, some well-known and established, and some that may have been created in response to a proposed DIW. A Class 1 well permittee may be unfairly associated with oil and gas operators or other non-related environmental issues. As an example, the spike in earthquakes in the past few years in an area of Oklahoma are a result of injection of oil and gas produced liquids. Again, to a layperson, they are likely to see that problem as potentially occurring on a Class 1 DIW project. Moreover, whether they are right or wrong, the permittee cannot ignore their concerns.
Preparation to address, mitigate, and overcome these issues can be a critical success factor in project planning and execution. This activity includes the development of stakeholder engagement and a public relations plan and having the right folks manage and conduct the interactions with the public. It is up to the permittee to explain the difference in a way the public and regulators can be comfortable with and understand. Not every professional is equipped to strike just the right tone with the public. Every DIW siting study and permit application is different. There are, however, some basic strategies to help diffuse some of the concerns to keep a Class 1 project moving forward; the over-arching issue is that the period to gain public and the regulator’s trust is short. Developing a level of trust and management of expectations between the permittee, regulator, and the public will facilitate obtaining a construction permit and eventually an authorization to operate the DIW. Keep in mind that every day a permittee operates his or her primary business, the public is watching and listening to what he or she says and what is done with regards to environmental impacts from the facility. Doing the right thing and gleaning public trust well before the DIW project comes up, starts to build a foundation of cooperation that can be positive for everyone and the DIW project. If the facility has had some major issues that were not managed well in the public’s eye, it just makes it tougher to sell the DIW project. So, it is never too soon to start building trust with the public and regulators.

Other Considerations
Due to the unique nature of deep subsurface drilling, there is always an element of geologic uncertainty or potential for loss of downhole tools as the project proceeds. The permittee should have a candid discussion with the technical team to identify key decision points in the well drilling process. These items are routine occurrences for drillers and the technical team, but there are cost and schedule impacts should such conditions occur. The best way to plan for these items is to discuss them early and build in a reasonable contingency in the capital estimate.

5.0 SUMMARY

The increasingly stringent surface water discharge standards are an ongoing challenge for industries generating a wastewater stream. DIWs should be considered as a potentially viable option for long-term, cost-effective wastewater disposal as other wastewater management alternatives are evaluated. Across the nation they currently provide an environmentally sound disposal option for many regions. However, DIWs can generate considerable public concern and pushback during the permitting phase. The pushback is often due to the issue of the injected wastewater being in close proximity to the public drinking water source or other significant ecological resource. A permittee should have a positive mindset to the back and forth nature of the regulatory review process. Be prepared to conduct proactive regulatory meetings; have complete, relevant, and current technical studies including consideration of other well sites and disposal technologies; and a thoughtful and well-rehearsed public presentation(s) to develop a case to produce the best outcome.
REFERENCES


BIOGRAPHY

Monte Markley, PG obtained a Bachelor of Science degree from the Lamar University in Beaumont, Texas in 1989. He serves clients nationwide with the SCS Engineers’ team as a senior project director and serves as their National Technical Partner for Deep Injection Wells. Monte’s project experience includes evaluation of industrial liquids management solutions, and Class 1 injection well permitting, design, and operations at power plants, mines, landfills, refineries, and meat packing and other industrial facilities. Monte may be contacted at MMarkley@scsengineers.com or 316-315-4501.