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RELEVANCE OF UNDERGROUND NATURAL GAS STORAGE TO GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE

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ABSTRACT

The practice of underground natural gas storage (UNGS), which started in the USA in 1916, provides useful insight into the geologic sequestration of carbon dioxide—the dominant anthropogenic greenhouse gas released into the atmosphere. In many ways, UNGS is directly relevant to geologic CO_2 storage because, like CO_2, natural gas (essentially methane) is less dense than water. Consequently, it will tend to rise to the top of any subsurface storage structure located below the groundwater table. By the end of 2001 in the USA, about 142 million metric tons of natural gas were stored underground in depleted oil and gas reservoirs and brine aquifers. Based on their performance, UNGS projects have shown that there is a safe and effective way of storing large volumes of gases in the subsurface. In the small number of cases where failures did occur (i.e., leakage of the stored gas into neighboring permeable layers), they were mainly related to improper well design, construction, maintenance, and/or incorrect project operation. In spite of differences in the chemical and physical properties of the gases, the risk-assessment, risk-management, and risk-mitigation issues relevant to UNGS projects are also pertinent to geologic CO_2 sequestration.

INTRODUCTION

Similarly to geologic carbon dioxide (CO_2) sequestration projects, large volumes of natural gas are stored in various subsurface structures. There are differences in gas properties and in modes of system operation (e.g., CO_2 is left underground while natural gas is periodically injected and withdrawn), but the experiences of the natural gas industry are for the most part germane to CO_2 storage projects.

Depleted oil and gas reservoirs and brine aquifers are used in seasonal (or base-load) storage and are operated to meet cyclic seasonal and/or daily demands. Salt caverns are also used for short-term storage because they can quickly switch from injection to withdrawal and operate at large injection and extraction rates. However, gas volumes stored in salt caverns are much smaller than in depleted reservoirs and aquifers. Because of the different operational modes and larger storage volume, storage in depleted reservoirs and aquifers is more applicable to CO_2 sequestration than storage in salt [1].

To date, depleted oil and gas reservoirs are (because of their wide availability) the most commonly used UNGS sites in North America. According to 1997–1998 figures, there were 458 active UNGS projects in the USA and Canada, and approximately 18,500 injection-withdrawal wells and 350 compressor stations were in operation [2,3]. In April 2002, 5.86×10^{12} cubic feet of natural gas was stored underground in the USA in depleted oil and gas reservoirs and brine aquifers, an amount corresponding to about 166×10^9 m^3, or about 119 million metric tons (assuming natural gas is pure methane) [4]. These are significant quantities, but are less than 10% of the USA anthropogenic emissions of greenhouse gases in 2000 (i.e., 1,906 million metric tons carbon equivalent) [5].

In depleted oil and gas reservoirs as well as in aquifers, the geologic structure is at least partially filled with water. When the stored natural gas is injected into the storage formation, it floats and displaces the native water. The water is forced away from the injection wells, and the formation pressure increases. If the volume injected is too large or the pressure is too high, gas may leak out of the reservoir.

Aquifer storage tends to be more expensive to develop than depleted reservoir storage because the geology, especially the structure of the aquifer, is usually unknown beforehand. In the case of depleted reservoirs, the presence of hydrocarbons testifies to the existence of a "container" and the quality of the caprock to hold fluids below it. On the other hand, in aquifer storage projects, the structure and quality of the storage formation and caprock need to be determined during development [6].

The main effort in converting depleted reservoirs to natural gas storage projects is in the reconditioning of wells and pipelines. This reconditioning is necessary because wells will be used for injection as well as withdrawal, and because operating pressures tend to be higher than during original oil and gas production. Wells must also be able to withstand the changes in stresses and temperatures associated with cycling operations. In addition, because the volumes of gas being withdrawn during peak winter periods are much larger than during normal oil and gas production operations, additional wells will have to be drilled.

The development of aquifers to store natural gas requires a number of exploratory studies generally not needed for projects involving depleted reservoirs. An appropriate underground structure with sufficient closure must be found. The quality of the caprock needs to be determined by examining cores and testing them in the laboratory and/or by carrying out well tests. Such tests are particularly useful for determining the large-scale features of the caprock that could not be determined from laboratory samples. If the results of these studies look favorable, the next step in the evaluation of the proposed aquifer-caprock system is to carry out pilot injection to initiate the growth of the gas bubble and continue testing the tightness of the caprock seal. For the gas to push the water away from the well(s), injection is performed at pressures that exceed initial aquifer values. The development of a commercial natural gas aquifer storage project requires between two and four years, and the size of the gas bubble is increased over periods of ten or more years [6].

RISK-ASSESSMENT FRAMEWORK AND METHODS

The major risks associated with the operation of an underground natural gas storage project are related to leakage from the storage structure. Leakage leads to two very different risks. One is economic, in that gas that has migrated from the structure may not be recoverable; consequently, a valuable commodity is lost. Second, leakage from the structure may migrate into a drinking-water aquifer and even to the land surface, in which case it could be a significant safety risk.

Overpressurization is a main cause of leakage. Underground natural gas storage projects are in many cases operated at pressures exceeding the original, or discovery, values. This high-pressure operation is needed to enlarge the gas bubble and obtain higher delivery rates, with only a moderate increase in risk of gas loss through defective wells [6]. This mode of operation creates pressure gradients that the storage formations have not experienced before. It could result in the displacement of the static water column, forcing water out of the caprock and causing gas to leak from the storage formation; this is known as exceeding the threshold displacement pressure or threshold pressure. Pressures that lead to fracturing the caprock are higher than those that are used in UNGS projects [6].

Leakage may also be the result of well failure (i.e., breaks in the casings, joints, or defective cementing of casings) and of fractures, faults, and solution cavities that permit upward gas movement through the seal. Well mechanical flaws have been the most common cause of leaks in underground gas storage facilities. Generally, such problems are fixed by repairing or reconditioning the wells; in extreme cases, the wells may have to be plugged and abandoned. Leaks that occur through the caprock are more difficult to detect and control [1]. In many states within the USA, underground natural gas storage facilities are required to implement methods to detect gas leakage. Several methods to identify leaks are being used; required monitoring activities vary from state to state [1].

RISK-MANAGEMENT APPROACHES FOR NATURAL GAS STORAGE

The U.S. Environmental Protection Agency has for the most part delegated the regulation and monitoring of UNGS projects to individual states. The key responsibility of the states is the protection of the environment, especially drinking-water aquifers, from endangerment by the injection and subsurface storage of natural gas. States are in charge of issuing permits based on the assumption that the operators of the facilities will run them within the parameters of required federal, state, and local regulatory agency permits, and that operations in excess of permitted levels would require new discretionary permits and additional review.

The projects have to be designed and operated in accordance with recognized engineering procedures. Regulatory agencies rely on the expertise of their technical staffs and that of hired consultants to assure that this will actually happen. All geologic and engineering data and test results provided by companies applying for operating permits have to be studied for completeness and accuracy before permits are issued. When the guidelines and regulations do not suggest criteria, professional judgment is used to develop reasonable thresholds and safeguards. When soliciting the permit for an underground natural gas storage project, applicants have to provide information showing that the reservoir is suitable and that it can be operated safely to prevent waste of resources, uncontrolled escape of gases, pollution of drinking water aquifers, and endangering life or property. Regulations for underground natural gas storage operations and associated monitoring activities vary between states. Requirements for UNGS projects are discussed in [1].

RISK-MITIGATION AND REMEDIATION METHODS

UNGS projects should be operated so as to avoid leakage of the stored gas, which might endanger life and property (including buildings and other man-made structures), water resources, and vegetation/crops. Regulations controlling the design, operation, and monitoring of the storage facilities are meant to reduce this risk to a minimum. Even though natural gas (essentially methane) is flammable and may cause fires and asphyxiation, once the leaks have been controlled, no long-term effects remain in the affected areas.

If a storage project presents an adequate geologic framework (i.e., appropriate structural closure and reservoir-caprock system) and is operated within regulated guidelines (i.e., properly constructed wells and surface installations, with reservoir pressure not exceeding prescribed values), with no unplugged abandoned wells in the area, no significant gas leaks should be expected. If gas leaks to the surface, it might be necessary to evacuate nearby residents because of the danger of explosion, fire, or asphyxiation. Generally, repairing or plugging of the leaking wells is sufficient to eliminate the problem. If the leaks are not related to well damage, the pressure in the storage aquifer or reservoir might have to be reduced. A project may be abandoned if leaks cannot be controlled or if the operations of the facilities have to be curtailed to such a low level that the undertaking is no longer practical. In that case, the gas remaining in the storage formation should be extracted as much as economically feasible, and all injection/withdrawal and observation wells open in that formation must be plugged.

CONCLUSIONS/FINAL REMARKS

Most of the experiences learned from operating UNGS projects in the USA for almost 90 years can be transferred to deep geologic storage of CO_2 activities. A number of factors are critical:

1. The site must be adequately characterized (i.e., permeability, thickness and extent of storage reservoir, caprock integrity, geologic structure, lithology, etc.)

2. The storage formation should be deep enough to allow sufficiently high gas pressures for the economic success of the operation.
3. Injection/withdrawal wells must be properly designed, constructed, monitored and maintained.
4. Overpressuring the storage reservoir above safe limits should be avoided. In UNGS projects overpressures of up to 17 kPa/m of depth have been used [6].
5. Abandoned wells in and near the project must be located and plugged.

While underground natural gas storage has been used safely and effectively, there have been a number of documented cases where leakage has occurred. In the vast majority of cases, it was caused by defective wells (poorly constructed or improperly plugged abandoned wells). As engineering practices have improved and regulatory oversight has grown more stringent over time, accidents have become rare. Modern procedures have made underground natural gas storage a safe and effective operation.

Monitoring is an important part of the regulatory oversight of UNGS projects. While regulations vary among states, almost all monitoring and reporting requirements focus on assuring that the wells are not leaking (e.g., taking pressure measurements and running downhole logs such as temperature, pressure, noise/sonic, and casing inspection). Observation wells installed and monitored for the purpose of verifying that gas has not leaked into shallower strata are rarely required; however, a few storage projects have over one hundred wells for this purpose. In the event that leakage occurs, remediation is possible by producing or venting the gas accumulated in shallower layers, and/or reducing reservoir pressure. In most cases, leakage is caused by the presence of leaking or abandoned wells. When a natural gas storage site is shut down, as much of the gas as is practical is removed from the formation. The injection wells are then plugged and abandoned using prescribed procedures. No long-term monitoring is required after a project has been shut down.

Natural gas industry experience has shown that is possible to safely store large volumes of gas underground over time, indicating the feasibility of sequestering carbon dioxide in subsurface geologic formations.

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