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Carbon storage in depleted gas fields: Key challenges

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Abstract

It is recognized that most of the available geological storage capacity for CO2 is in saline aquifers. The best aquifers are likely to be in sedimentary basins (and in many cases near to fossil energy sources). However, unless the formations have been explored for hydrocarbon potential, it is likely that little data exists so significant work will be required to evaluate the realistic storage potential. Depleted gas fields offer more limited capacity but are better characterized, have seals that have successfully retained hydrocarbon gas for millions of years, and may offer a shorter route to practical implementation for early projects.

Estimates indicate that depleted offshore gas fields in UK waters have the potential to store around 3.8 billion tonnes of CO2. This is a significant capacity and an inviting target particularly if existing infrastructure and wells can be reused.

This paper explores the issues around injecting and storing CO2 in highly depleted gas fields using a case study based on the characteristics of a Southern North Sea gas field. The study shows that assessing and managing the flow control aspects of CO2 injection, particularly initially when the reservoirs are at very low pressure is going to be a major technical challenge. The challenges include a requirement for a high -tech flow control device at the base of the tubing to allow the dense phase CO2 to be expanded in a controlled manner. Also the requirement for CO2-specific well flow performance software as conventional software, designed to model the flow of hydrocarbons, is not necessarily sufficiently rigorous when modeling a complex fluid like CO2, particularly the thermodynamics aspects. Understanding and mitigating Joule Thomson effects is necessary to avoid the possible formation of ice and gas hydrates.

Without a comprehensive understanding of CO2 flow systems and accurate modeling of the thermodynamic effects it may not be possible to realize the potential that gas field storage offers.

Keywords: CO2 storage; gas fields; CO2 injection systems

1. Introduction

It is recognized that most of the available geological storage capacity for CO2 is in saline aquifers. The best aquifers are likely to be in sedimentary basins (and in many cases near to fossil energy sources). However, unless the formations have been explored for hydrocarbon potential, it is likely that little data exists so significant work will be required to evaluate the realistic storage potential. Depleted hydrocarbon reservoirs offer more limited capacity but are better characterized, and may offer a shorter route to practical implementation for early projects.

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Oil fields present the opportunity for enhanced oil recovery (and a revenue stream from the additional oil produced) although so far there have been no offshore CO2 EOR applications. Depleted gas fields are usually well characterized and have seals that have successfully retained hydrocarbon gas for millions o f years.

The British Geological Survey (BGS) estimate that depleted gas fields in UK waters could store 2.8 billion tonnes of CO2 in the Southern North Sea (SNS) fields and 1 billion tonnes in the East Irish Sea (EIS) fields (Bentham, 2006 and Kirk, 2006).

This paper explores the issues aroun d injecting and storing CO2 in highly depleted gas fields using a case study based on the characteristics of a SNS gas field..

2. Pressure response during depletion

When a gas field is produced the characteristic of its pressure response can fall into three broad categories (Figure 1). If there is no aquifer support (Type 1) then the pressure will deplete more or less linearly with the cumulative gas produced, the recovery will be in excess of 90%, and the abandonment pressure will be very low. If there is l imited or weak aquifer support (Type 2), then the normal pressure decline in response to gas production is reduced somewhat by small amounts of water influx and the recovery factor is limited to around 70% with significantly higher abandonment pressures. Once production has ceased the pressure increases (albeit relatively slowly) in response to further aquifer influx. Gas fields with a strong aquifer response (Type 3) have relatively poor recoveries (of order 40%) as the invading water chokes the wells. Any pressure decline during the production phase is quickly made up by the aquifer.

Gas fields with Type 1 and Type 3 pressure responses are likely to provide the best candidates for CO2 storage. Type 1 because there is clearly a pressure 'sink' into whi ch to inject the CO2; and it is a generic field of this type that is the subject of the rest of this paper. Type 3 because by analogy if the water can flow quickly into the pressure sink created by produced hydrocarbon gas, then the water should flow away quickly in response to the pressure spike from the injected CO2. A Type 2 response is much more problematic when considering CO2 disposal. There will be some initial capacity compressing up the remaining hydrocarbon gas but after this additional capacity will depend on the rate at which the aquifer will relax in response to the CO2 injection which may be too low for practical application.

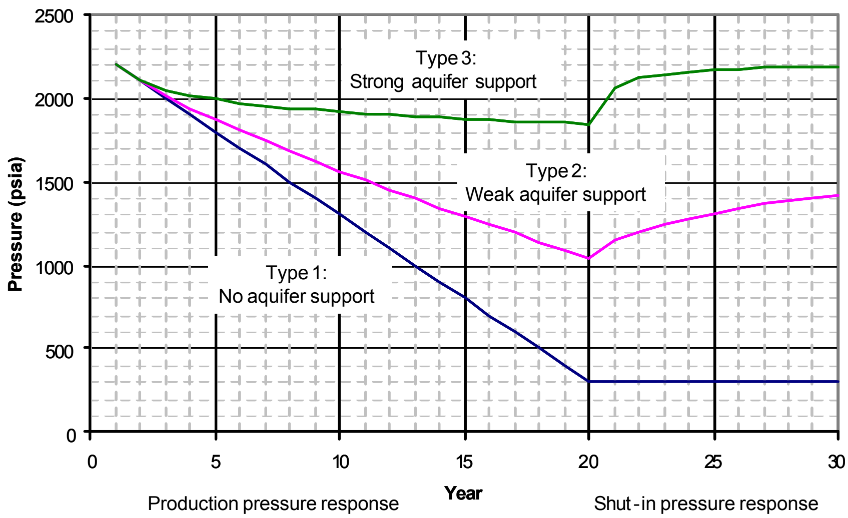

Figure1 Typical gas field pressure responses

3. 'Pack up'

The density of CO_2 by comparison with hy drocarbon gas means that a lot can stored in the pore space from which hydrocarbon gas has been produced, particularly at shallower depths. We can define 'pack up' as the ratio of surface volumes of CO_2 and hydrocarbon gas (principally methane) that can be stored in the same volume of pore space at the same temperature and pressure. Figure 2 shows pack-up with depth for typical UK Continental Shelf geothermal and hydrostatic gradients. The pack-up is around 3.5 at the depth of the EIS gas fields (~3,000 ft or ~914 m), and about 1.5 at the depth of the SNS gas fields (~10,000 ft or ~3,048 m).

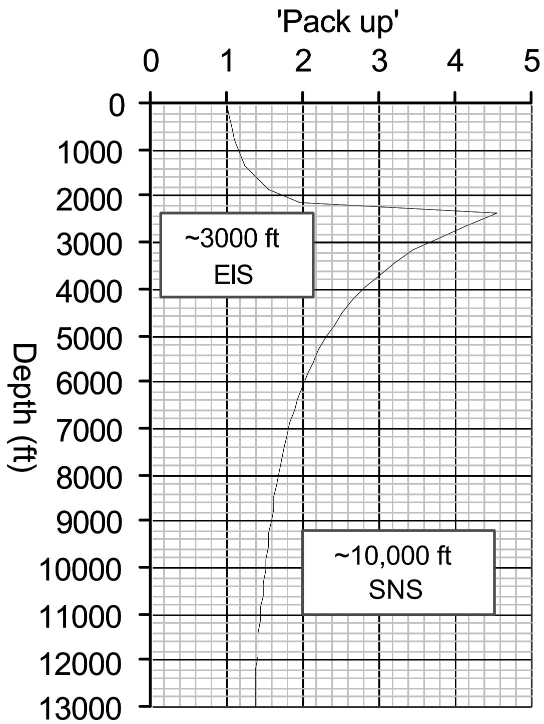

Figure 2 'Pack up' with depth for typical UK Continental Shelf geothermal and hydrostatic gradients

4. Generic SNS gas field used for case study

The study reported here uses a representative SNS Gas Field. This is at a depth of 10,000 ft (3,048 m), has an initial pressure (prior to hydrocarbon gas production) of 4,500 psia (310 bara) and a reservoir temperature of 200°F (93°C). The porosity and permeability are assumed to be constant at 15% and 50 milliDarcy respectively. The original gas in place is around 1 trillion standard cubic feet or scf (28 billion standard cubic meters or scm), with a recovery factor to an abandonment pressure of 350 psia (24 bara) of 90%.

The objective is to see if the field can be used to inject 200 million scf per day of CO_2; the amount that would be captured at a 500-800 MW coal fired power station depending on the load factor. This is equivalent to 5.7 million scm per day or ~3.9 million tonnes per year.

5. Simulation model

The injectivity and storage capacity were investigated using a 1D single well compositional model with a radial grid (Figure 3). Based on the field dimensions and permeability, two injection wells each injecting 100 million scf/d (2.8 million scm/d) are likely to be sufficient, so the model was set up to represent half the volume of the field.

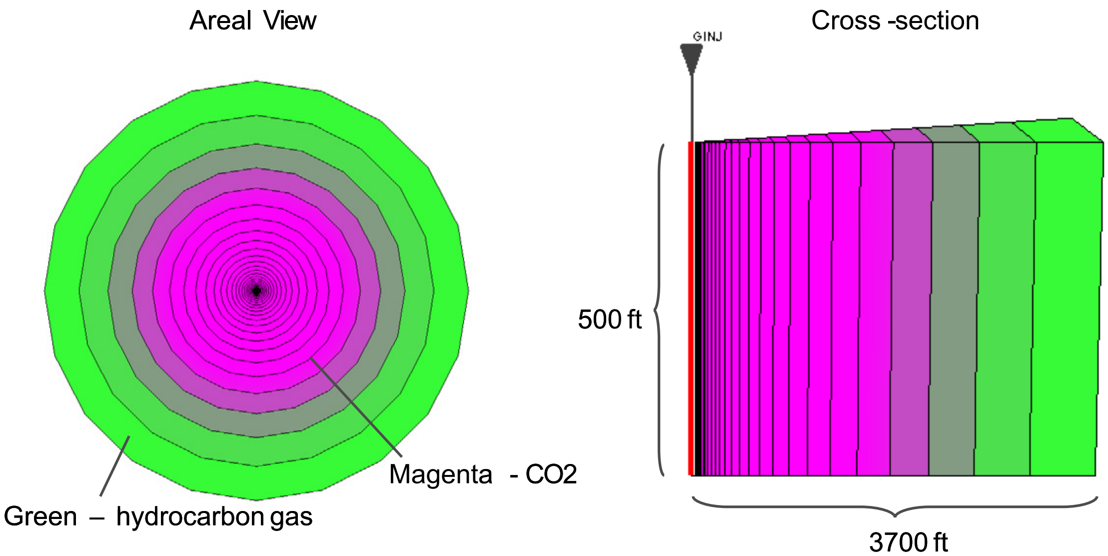

Figure 3 Simulation model showing CO2 distribution after one year

The CO2 is injected into the small amount of hydrocarbon gas remaining. Figure 3 shows the situation after one year of injection. Of course the behavior is somewhat simplified in this simulation as in practice it is likely that heterogeneity would cause the CO2 and hydrocarbon gas to mix to some extent. There would also be a tendency for the gasses to segregate under gravity. However, it is believed that the model is sufficient for a first pass determination of injectivity and storage capacity.

The simulations show that using two injectors it is possible to inject 200 million scf/d (or 5.7 million scm/d) for 25 years and store a total of 97 million tonnes. During this time the average field pressure (Figure 4) rises from the field abandonment pressure of 350 psia (24 bara) to the original field pressure of 4,500 psia (310 bara). The pressure at the point of injection (also shown in Figure 4) is always higher than the average pressure. Initially the inflow pressure drop is around 400 psi (28 bar) while the CO2 is being injected as a low density gas but this decreases to around 200 psi (14 bar) later on when the CO2 is being injected in the dense phase. Thus the CO2 injection system has to be designed to deliver the CO2 bottom hole at a pressure of around 750 psia (52 bara) initially, rising to 4,700 psia (324 bara).

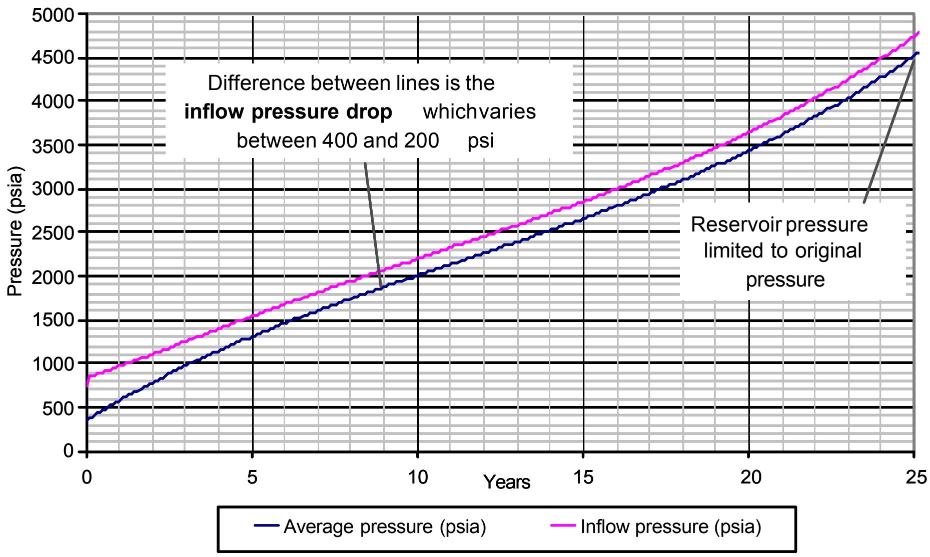

Figure 4 Reservoir pressure response to CO2 injection

6. Injection system

For practical and economic reasons, it is normal to transport CO2 in surface and seabed pipelines in the dense phase. At the seabed temperature of around 40°F (4.4°C), and allowing for a safety margin, the CO2 would need to arrive at the injector well heads at a pressure of 1,000 psia (69 bara) or higher. The behavior of the CO2 in the injection well can be modeled usi ng well flow performance software. Note, however, that in the main this software is designed to model the flow of hydrocarbons and needs to be used with caution when modeling CO2. The result of a typical calculation is shown in Figure 5. The CO2 is assumed to flow down the well in a 7 inch pipe (know as tubing) at a rate of 100 million scf/d (2.8 million scm/d). As the CO2 flows down the well there is a pressure increase from the weight of the column negated by friction losses. In addition the CO2 heats from the injection temperature of 40°F (4.4°C) to around 100°F (38°C) at the base of the tubing. This is as a result of heat flux from the geological formation around the well, although the CO2 does not equilibrate with the external temperature. This would only occur in the tubing at very low injection rates. The CO2 does, however, heat up to the reservoir temperature of 200°F (93°C) after injection although this process is not straight forward.

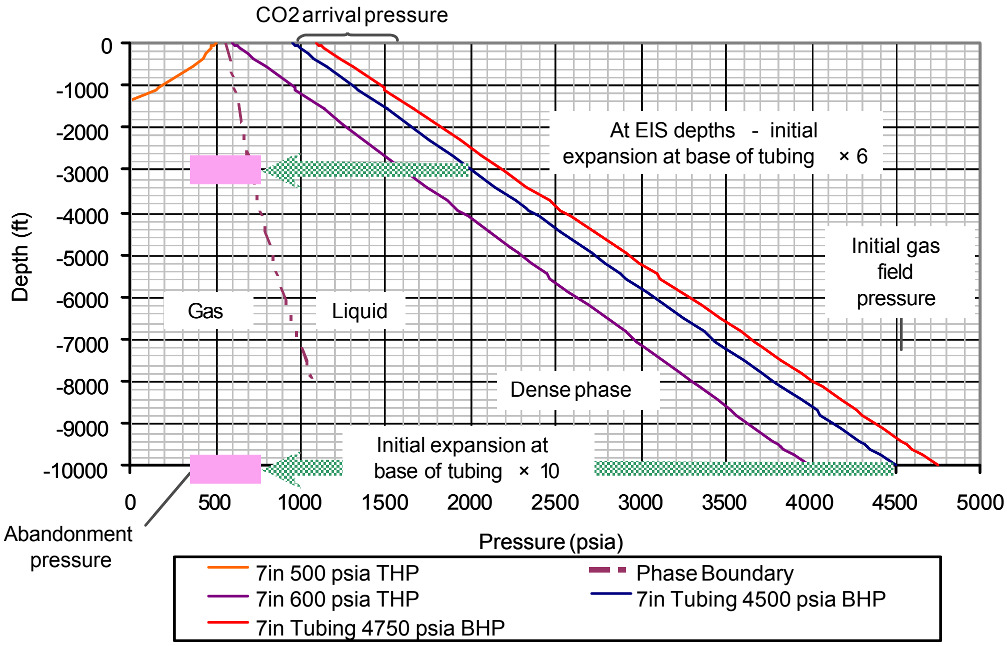

Figure 5 Pressure in injection well tubing during CO2 injection

The bold blue and red lines in Figure 5 show the pressure along the tubing for tubing head pressures of just under 970 psia (67 bara) and 1,100 psia (76 bara) respectively. Even with the friction losses this delivers the CO2 at the base of the tubing (10,000 ft, 3048 m sub sea) at pressures of 4,500 psia (310 bara) and 4,750 psia (328 bara) respectively. Initially this is much higher than the bottom hole pressure required to inject the CO2 into the reservoir which is only 750 psia (52 bara), although this mismatch in pressure will decline in time as the reservoir fills up with CO2 and the pressure increases. It would be possible to lower the tubing head pressure such that the bottom hole pressure is reduced to 4,000 psia (276 bara) - shown by the purple line, but this would take the surface pressure dangerously near to the pressure below which the CO2 in the tubing would become gas. It is not possible to inject the CO2 in the gaseous state as the friction would far outweigh the pressure head as indicated by the orange line. The broken line shows the dividing line between the CO2 in the tubing being in the gaseous or liquid state; beyond the base of the line it is supercritical.

If the high pressure dense phase CO2 is discharged directly into the low pressure reservoir without a controlled expansion, then the low pressure in the reservoir would reflect back up the tubing and choke-off the flow. Thus in order to store the CO2 in the initially low pressure reservoir it will be necessary to fit an expansion cum flow control device at the base of the tubing which would need to be adjustable with time. The expansion will need to be done against friction in order to counter the Joule Thomson cooling effect which could potentially result in the formation of ice and gas hydrate. Such a flow control device is quite high-tech so disposal in depleted gas fields is not going to be easy with serious attention needing to paid to flow assurance. The volumetric expansion required initially at a typical SNS depth of 10,000 ft (3048 m) is around ten times. At the shallower reservoir depths in the EIS this factor is around six times.

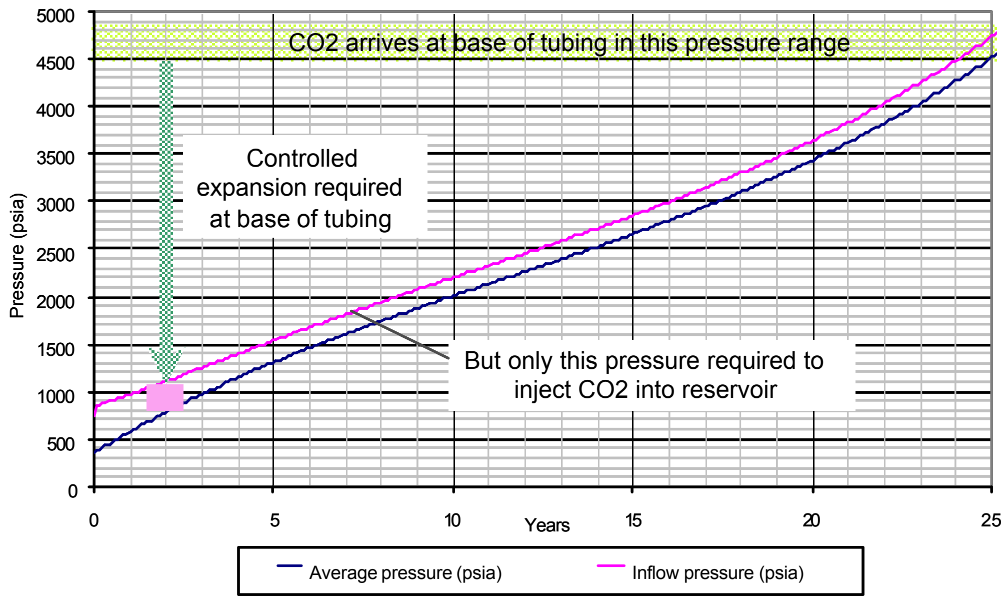

Figure 6 Pressure at base of tubing compared to reservoir pressure response

Figure 6 shows that the amount of expansion required reduces with time. A CO2 delivery pressure at the base of the tubing of 4,500-4,750 psia (310-328 bara) is sufficient to repressurize the reservoir to near its original pressure and store around 97 million tonnes of CO2 and there could be some additional capacity if the delivery pressure were raised.

7. Further analysis

In some depleted gas fields where the abandonment pressure is extremely low, it may be possible to achieve limited disposal with the CO2 injected from the surface as a gas. It could arrive by pipeline already as a gas or be converted to a gas at the surface.

In the example above the injection rate was such that the friction pressure loss was greater than the pressure gain in the tubing when the CO2 was being injected as a gas (Figure 5 – orange line). However, for the lower rate of 25 million scf/d (0.7 million scm/d) as opposed to 100 million scf/d (2.8 million scm/d), the friction pressure loss is lower and there is sufficient pressure for the CO2 to reach the base of the tubing.

Figure 7 shows the results of a simplified calculation for an injection rate of 25 million scf/d (0.7 million scm/d) with a 5½ in tubing looking at the situation for a range of THPs (50 to 1,400 psia in steps of 50 psi), assuming an injection temperature of 40°F (4.4°C). There is a further assumption that the flowing CO2 increases in temperature by 80 degrees F (44 degrees C) during its transit from the top to the base of the tubing. This is an approximation but is consistent with the lower temperature rise seen in the more detailed calculation for a higher injection rate using oil industry standard software (Figure 5). The results in Figure 7 are plotted as a function of pressure and temperature, but as noted above temperature is increasing with depth so the temperature axis can also be interpreted as depth. At this lower injection rate it is possible to inject in the gas phase for THPs in the range 350 to 550 psia and achieve

BHPs in the range 292 to 1,060 psia. However, for THPs of 600 psia and above the CO2 changes to the liquid phase and the minimum BHP achievable is 4,421 psia, so it will only be possible to inject CO2 in the gas phase up to a reservoir pressure of 1,060 psia. Thus for a continuous range of THPs there is a discontinuous range of BHPs with no solution for BHPs in the range 1,060 to 4,421 psia.

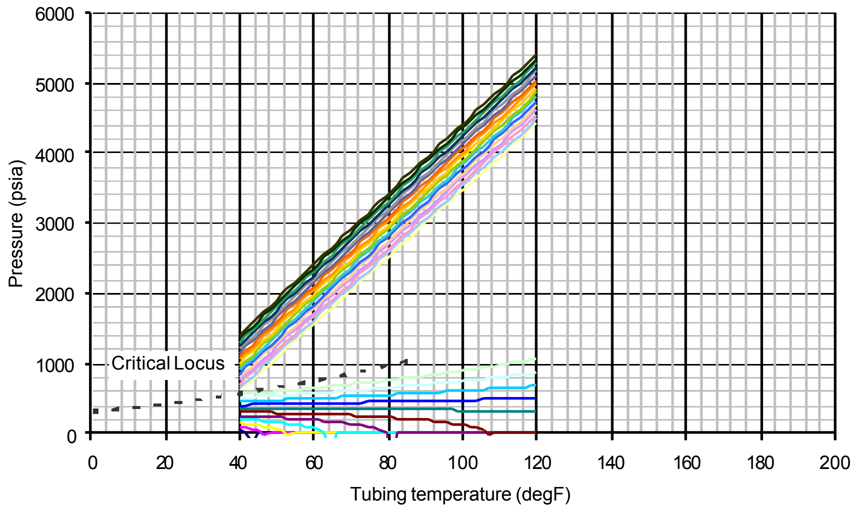

Figure 7 Tubing pressures assuming injection temperature of 40°F (4.4°C)

A way round this problem would be to heat the CO2 at the surface to above its critical temperature. This is the situation shown in Figure 8 where the injection temperature has been raised to 100°F (38°C), and it is again assumed that the temperature increases by 80 degrees F (44 degrees C) during its transit through the tubing. This transforms the situation. Now for THPs in the range 400 – 1,400 psia there is a continuous range of BHPs from 335 to 4,446 psia. However, calculations suggest that the additional costs to supply the heat to achieve this would be prohibitive, so for injection in the liquid/dense phase it would appear that there is no escaping the requirement for the down-hole flow control device described above.

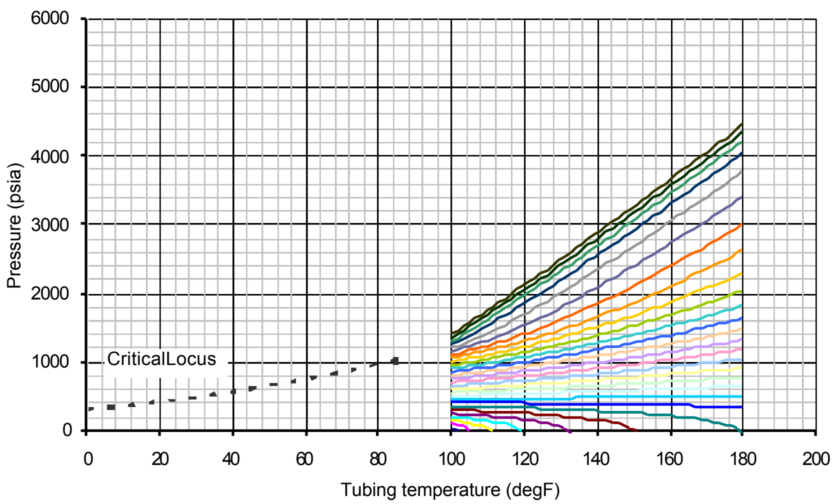

Figure 8 Tubing pressures assuming injection temperature of 100°F (38°C)

8. Conclusions

Previous estimates indicate that there is significant capacity to store CO2 in depleted Southern North Sea (SNS) and East Irish Sea (EIS) gas fields. However, this case study shows that assessing and managing the flow control aspects of CO2 injection, particularly initially when the reservoirs are at very low pressure is going to be a major technical challenge.

The challenges include a requirement for a high-tech flow control device at the base of the tubing to allow the dense phase CO2 to be expanded in a controlled manner. Also the requirement for CO2-specific well flow performance software as conventional software, designed to model the flow of hydrocarbons, is not necessarily sufficiently rigorous when modeling a complex fluid like CO2, particularly the thermodynamics aspects. Understanding and mitigating Joule Thomson effects is necessary to avoid the possible formation of ice and gas hydrates.

Without a comprehensive understanding of CO2 flow systems and accurate modeling of the thermodynamic effects it may not be possible to realize the potential that gas field storage offers.

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